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March 11, 2019

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC)

Application for Approval of a Multi-Year Rate Plan for 2020 through 2024

Enclosed please find FortisBC's Application for Approval of a Multi-Year Rate Plan for the years 2020 through 2024.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.
FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties in the following proceedings:

- FEI and FBC 2014-2018 PBR Proceeding
- FEI Annual Review for 2019 Rates
- FBC Annual Review for 2019 Rates

Pre-Application MRP Workshop Participants and Stakeholders

FortisBC Energy Inc.

and

FortisBC Inc.

Application for Approval of a Multi-Year Rate Plan for 2020 through 2024

Volume 1 - Application

March 11, 2019

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Section A:

OVERVIEW

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A: OVERVIEW

1. EXECUTIVE SUMMARY

1.1 APPLICATION AND REGULATORY PROCESS

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC, the Utilities or the Companies) seek approval from the British Columbia Utilities Commission (BCUC) of multi-year ratemaking plans (Proposed MRPs) for the years 2020 through 2024 (Application). More specifically, FortisBC is seeking approval for the framework of the Proposed MRPs that include, amongst other items, an indexed approach to Operations and Maintenance (O&M) expense, a forecast cost of service approach to capital, Service Quality Indicators (SQIs), targeted incentives for the performance of the Companies, and an innovation fund. FortisBC is also seeking approval of deferral accounts to implement the Proposed MRPs, updated depreciation rates and other supporting studies, and other approvals for the term of the Proposed MRPs. The approvals sought in the Application are set out in detail in Section A2 and draft forms of the final Orders are included in Appendix E2.

The Proposed MRPs build on the successes of FEI's and FBC's current multi-year performance-based ratemaking (PBR) plans (Current PBR Plans), while making changes to respond to the challenges experienced, stakeholder feedback, and changes in FortisBC's operating environment. Because many aspects of the Proposed MRPs remain similar or unchanged compared to the Current PBR Plans, the Companies believe that this Application can be addressed efficiently and effectively by way of a written public hearing process. In recognition that the BCUC may not be in a position to determine the appropriate regulatory process until after the first round of information requests (IRs), FortisBC has proposed a draft preliminary regulatory timetable consisting of a workshop on key elements of the proposal, an initial round of IRs, and then a procedural conference to determine the rest of the regulatory process. FortisBC's proposed regulatory process is set out in Section A3 and a draft procedural order is included in Appendix E1.

1.2 RESPONSE TO THE EVOLVING OPERATING ENVIRONMENT, CURRENT PBR PLANS, AND STAKEHOLDER CONCERNS

Section B of this Application provides an in-depth review of FortisBC's evolving operating environment and rate setting history, and the implications that these have for the Proposed MRPs. FortisBC's operating environment has continued to change over the term of the Current PBR Plans. Key influences that are becoming increasingly predominant are:

- Policy direction and mandate from all levels of government towards decarbonization;
- Changing customer expectations with respect to service, engagement channels and keeping pace with other service providers;

- Increased need for engagement with stakeholders and Indigenous communities as a result of stakeholder activism and provincial and federal policy change;
- Increased need for maintenance and investment in our aging infrastructure to continue to provide safe, reliable services along with increased need to provide for physical and cyber security; and
- Increased need for innovation and the adoption of new technologies to improve operations, enhance customer service levels and meet decarbonization policy objectives.

These influences present challenges and opportunities to which FortisBC will need flexibility to respond over the term of the Proposed MRPs.

FortisBC's Current PBR Plans have been successful in many respects, including reducing O&M costs. However, the opportunities to reduce O&M costs are diminishing, and the benchmarking studies filed in Appendix C2 of this Application show that FEI and FBC perform well against industry peer benchmarks in terms of O&M spending. Our stakeholders have also expressed concerns with aspects of our Current PBR Plans, including the diminishing opportunities for operating savings, the effectiveness of the capital funding formula and incentive mechanisms, and the need to address government energy policy. Looking to other jurisdictions, FortisBC sees other utilities and regulators struggling with similar issues, and notes the adoption of a range of ratemaking approaches, from forecast multi-year rate plans with outcome-based targeted incentives to fully indexed-based multi-year ratemaking plans in the form of revenue or price cap indexes.

To address the influences in the operating environment, the experience with the Current PBR Plans, and stakeholder concerns, the key design themes of the Proposed MRPs are as follows:

- A five-year rate plan that includes incentive for the Utilities to perform. The five-year term promotes regulatory efficiency, sustained utility focus on managing the business, and flexibility to address emerging issues.
- Stable levels of O&M funding that are sufficient to address emerging pressures. This will provide certainty to support longer-term plans and initiatives, and encourage utility management to focus on the efficient allocation of resources within the business over time.
- A flexible approach that allows FortisBC to innovate and adapt to the changing environment. This is key to managing the transition to a lower carbon economy, while achieving a balance between affordability and lower emissions.
- Incentive to invest in the future through load growth opportunities. This will help offset the costs associated with climate policy and meeting emissions reduction targets as well as meeting growing demand for investment in system integrity and reliability.

The evidence in Section B1 of this Application shows that FortisBC's rate plans must evolve in response to changes in the operating environment, our experience with the Current PBR Plans, and stakeholder feedback. As a result, at this time, a multi-year rate plan framework that provides stable levels of O&M funding, the flexibility to innovate and adapt to the changing environment, and incentive to invest in our future is needed, and will help position FortisBC to continue to provide service to customers as the economy transitions towards a lower carbon future.

1.3 *PROPOSED MULTI-YEAR RATEMAKING PLANS*

Section C of the Application sets out the details of FortisBC's Proposed MRPs. In designing the Proposed MRPs, FortisBC has built on the successes of the Current PBR Plans, and responded to stakeholder feedback and its changing operating environment. FortisBC has also been guided by commonly accepted rate plan principles, such as aligning the interests of customers and the Utilities. The result is Proposed MRPs with the essential features necessary for the Companies to address the challenges in their operating environment and continue to provide safe and reliable service to customers.

1.3.1 Components of the Multi-Year Ratemaking Plans

Most elements of the Proposed MRPs are identical for FEI and FBC. The Proposed MRPs will determine natural gas delivery rates and electricity rates over the 2020 to 2024 period, reflecting the costs necessary to build, maintain, finance and operate the infrastructure necessary to provide service to customers. The table below summarizes the terms of the Proposed MRPs proposed by FortisBC.

Table A1-1: Summary of Proposed MRPs

Element	Proposed MRPs
Term	A five-year term from 2020 to 2024 is proposed.
Inflation Index (I-Factor)	A weighted average of Average Weekly Earnings for B.C. (AWE:BC) for labour costs and Consumer Price Index for B.C. (CPI:BC) for other costs will be used to determine the I-Index, which will be calculated annually.
Controllable Expenses - O&M	An inflation-indexed unit cost approach for O&M is proposed. A base of 2019 O&M per customer is adjusted for inflation and multiplied by a forecast of customers. O&M will not be rebased during the term of the Proposed MRPs but will be subject to true-up for actual customers.

Element	Proposed MRPs
Controllable Expenses - Capital	***FEI***: A unit cost approach is proposed for FEI's growth capital; other regular capital will be undertaken according to a five-year capital forecast. The growth capital formula is tied to forecast gross customer additions and the unit cost is inflation-indexed. Growth capital will not be rebased during the Proposed MRP term but will be subject to true-up for actual gross customer additions. ***FBC:*** Regular capital expenditures will be undertaken according to a five-year capital forecast.
Growth Factor	Customer growth forecast annually with true-up for actual in the following year(s).
Forecast O&M and Capital	Certain O&M and capital items do not fit well within formula because, for example, they are tied to parts of the business that are changing in response to government policy. These costs will be forecast each year in the annual review and variances will be captured in the Flow-through deferral account.
Forecast Revenues and Margins	Revenues are forecast each year for rate setting purposes. The Companies will continue to flow variances in revenue through the Flow-through deferral account. FBC will continue to flow variances in power supply costs through the Flow-through deferral account.
Non-Controllable Expenses	Certain O&M and capital expenditures, and interest and tax rates outside the control of the Companies will be forecast on an annual basis. Variances will be flowed through in rates.
Innovation Fund	FortisBC is proposing a fund aimed at research and development and demonstration of the viability of new technologies. The funding proposal recognizes the need to accelerate investment in innovation in order to provide customers with clean and cost-effective energy sources for the future. This fund will help the utilities gain the flexibility to innovate and adapt to the changing environment.
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and BCUC decisions will be flowed through in rates, subject to BCUC approval.
Service Quality Indicators	***FEI***: 13 SQIs (9 SQIs with a target benchmark and 4 informational measures) are proposed that deal with customer service, employee safety and reliability. ***FBC***: 12 SQIs (8 SQIs with a target benchmark and 4 informational measures) are proposed that deal with customer service, employee safety, and reliability.
Earnings Sharing Mechanism (ESM)	FortisBC is proposing a 50:50 ESM between customers and the Companies for earnings above and below the allowed Return on Equity (ROE).
Targeted Incentives	The Proposed MRPs include targeted incentives to align interests in achieving climate objectives while also investing in the future of the business through traditional and non-traditional load growth opportunities to the benefit of ratepayers and the utilities. FortisBC is proposing an annual financial incentive in the form of additional basis points added to the Companies' allowed ROE, based on the Companies' level of success in attaining the overall composite scorecard target.

Element	Proposed MRPs
Efficiency Carryover Mechanism (ECM)	FortisBC proposes an ECM in the form of an add-on to the approved ROE for two years after the end of the Plans' term. The ROE add-on is equal to one-half of the difference between the average achieved and authorized ROE, to a maximum of 50 basis points, over the last two years of the Plans (providing the difference is positive).
Off Ramps	A review of the Proposed MRPs may be triggered by either a 200 basis point ROE variance (post-sharing) above or below the allowed ROE, or a 150 basis point ROE variance for two consecutive years.
Annual Review	Annual reviews are proposed for the Proposed MRPs. FortisBC will file its forecasts revenue and costs outside of indexed amounts, and the BCUC will determine the rates for the upcoming year.

FortisBC believes the above elements will work together to provide an appropriate rate setting framework for the upcoming five-year period. The major components of the Proposed MRPs are discussed in more detail in the following sections.

1.3.2 Indexed-O&M

For the bulk of FEI and FBC's O&M expenses during the term of the Proposed MRPs, the amount to be included in rates will be determined using an O&M per customer amount indexed for inflation. This index-based O&M is designed to capture the savings achieved over the Current PBR Plans, provide FEI and FBC reasonable and necessary revenue to provide service to customers over the terms of the Proposed MRPs and encourage FEI and FBC to do more with what they have.

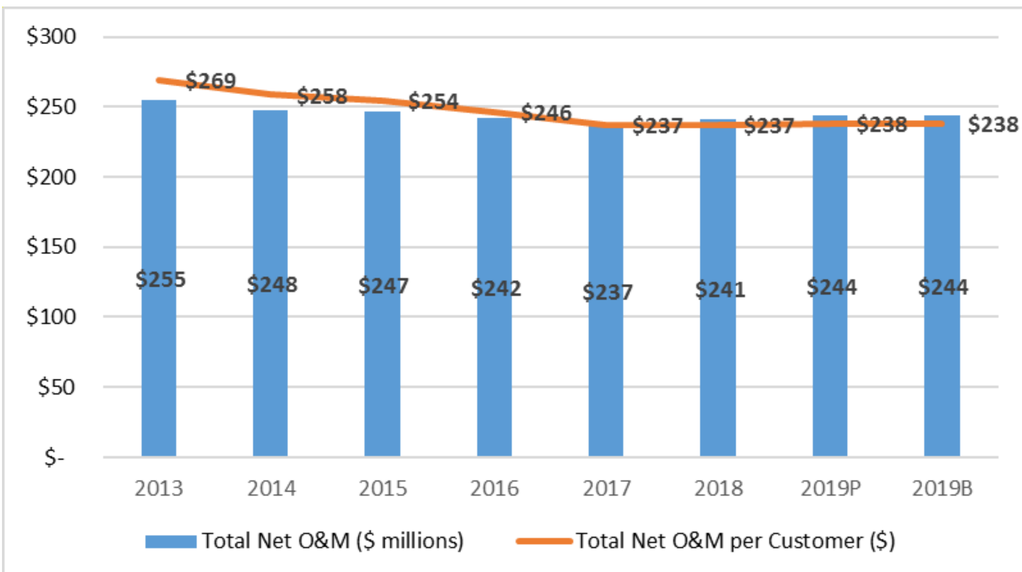
The starting point for determining the O&M per customer is the 2019 Base O&M, which is the adjusted actual O&M expenditures for 2018 expressed over the average number of customers in 2018, escalated by the approved formula inflation factors for 2019. FortisBC's 2018 O&M expenditures per customer is an appropriate starting point as it incorporates the productivity savings achieved over the current PBR Plans and reflects the current costs necessary to meet safety standards and other service requirements. FortisBC is proposing to adjust the 2018 O&M for known and measureable changes and is requesting incremental funding to support initiatives that address future key issues and challenges in the operating environment. After these adjustments, both FEI's and FBC's proposed 2019 Base O&M are lower than the O&M levels prior to the start of the Current PBR Plans[1], due to permanent savings achieved over the term of the Current PBR Plans being embedded in the O&M levels going forward.

[1] FEI: On an inflation adjusted basis, 2019 Total O&M per customer of $285, 2019 Formula Base O&M per customer of $250 compared to 2013 Total O&M per customer of $314, 2013 Actual Formula O&M per customer of $286.
FBC: On an inflation adjusted basis, 2019 Total O&M per customer of $439, 2019 Formula Base O&M per customer of $416 compared to 2013 Total O&M per customer of $495, 2013 Actual Formula O&M per customer of $457.

Each year of the Proposed MRPs, the component of rates designed to recover O&M expenses will adjust the previous year's calculated amount for customer growth and inflation. This adjusted amount is designed to provide O&M funding for the Companies to maintain their high service quality levels and address the challenges in their operating environment, including changes in regulations, compliance requirements, customer expectations, growing customer base, and climate policy. As FortisBC knows there are emerging pressures that have not been included in the Base O&M, and expenses that will increase at a rate higher than inflation, the indexed-O&M amount will encourage the Companies to do more with what they have.

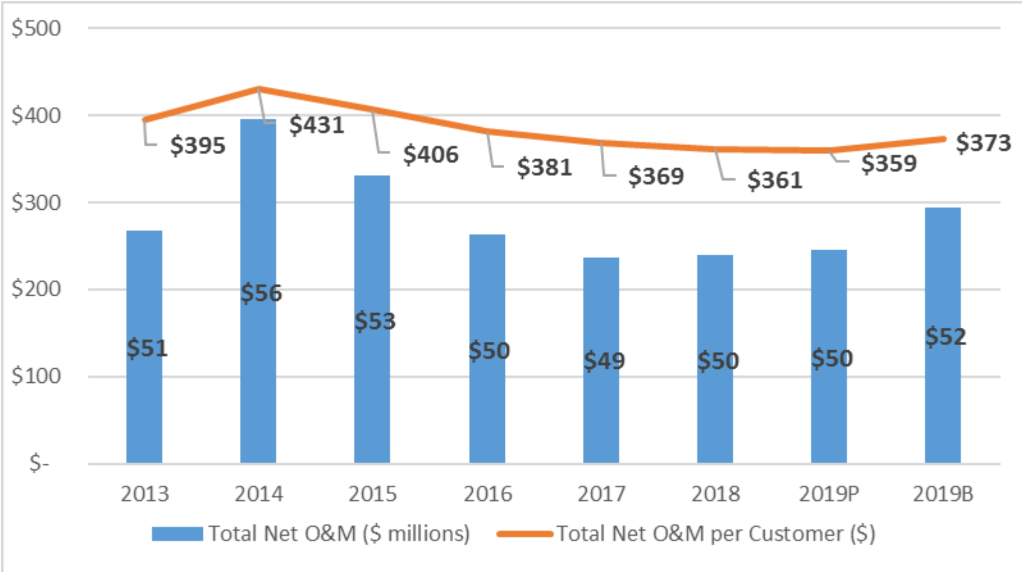
Ultimately, as seen in the tables below, FEI's and FBC's proposed 2019 Base O&M is lower than the O&M for FEI and FBC at the start of the Current PBR Plans, net of capitalized overheads. This shows that the proposed Base O&M captures the savings achieved over the Current PBR Plans.

Figure A1-1: FEI Actual Net O&M in Real Dollars from 2013 to 2019 Base (2019 B)[2]



2 FEI capitalized overhead rate is proposed to change from 12 percent to 16 percent in 2020; this is reflected in the graph.

Figure A1-2: FBC Actual Net O&M in Real Dollars from 2013 to 2019 Base (2019 B)[3]



1.3.3 Capital Forecast

FortisBC is proposing to determine the majority of its capital expenditures using a five-year forecast of capital expenditures, while retaining a unit cost approach for only those categories of capital that can be suitably managed within a formula.

FEI and FBC's Regular capital expenditures are divided into the following categories:

- Growth capital:
  - For FEI, this consists of expenditures for the installation of new mains, services, meters, and distribution system improvements to support customer additions.
  - For FBC, this consists of expenditures for infrastructure upgrades required to meet demand for new customers and/or load growth.
- Sustainment capital:
  - For FEI, this consists of expenditures for meter exchange programs, replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability, and expenditures for mains and service renewals and alterations.
  - For FBC, this consists of expenditures for system reinforcements, asset replacements and upgrades to the generation, transmission and distribution assets, to ensure safety, integrity and reliability.

[3] FBC capitalized overhead rate changed from 20 percent to 15 percent of Gross O&M in 2014.

- Other capital, which for FEI and FBC consists of expenditures for information systems, equipment and facilities.

The Application seeks approval of a forecast of FEI's Sustainment and Other capital and all of FBC's Regular capital expenditures from 2020 to 2024 which will be incorporated into FEI's and FBC's rates in the Proposed MRPs. FEI is proposing to continue with a unit cost approach for its Growth capital.

As is the case in the Current PBR Plans, FEI and FBC will seek approval of Major Projects in separate proceedings. Major Projects are projects over $15 million for FEI and over $20 million for FBC.

Due to its evolving operating environment and other uncertainties inherent in a five-year forecast, FortisBC proposes to review its forecast capital for 2023 and 2024 in its Annual Review for 2023 rates. Should FortisBC deem necessary, it will file an updated forecast of the 2023 to 2024 expenditures in 2022 to account for any material changes to the forecast that occur over that time period and ask for approval of the changes.

1.3.3.1 FEI Growth Capital

FEI proposes to continue with a unit cost approach to determining Growth capital. The inputs used for calculating Growth capital under the Proposed MRP include:

1. The 2019 Unit Cost Growth Capital Base: The 2019 Base unit cost is the average 2016-2018 actual Growth capital costs per Gross Customer Addition, with adjustments for known and measurable changes.
2. A forecast of gross customer additions: A Gross Customer Addition is a new service to a new customer or customers. FEI proposes to forecast is gross customer additions in each Annual Review, subject to a true-up in each subsequent year.
3. The composite I-Factor value: A weighted average of AWE:BC for labour costs and CPI:BC for other costs will be recalculated in each Annual Review.

The following equation illustrates the formula applied to Growth Capital (GC):

$$GC_t = UCGC_{t-1} \times (1 + I) \times GCA_t$$

Where: $GCA = Gross\ Customer\ Additions$
$UCGC = Unit\ Cost\ Growth\ Capital$
$I = Inflation\ Factor$
$t = Forecast\ year$

As seen above, the Growth capital formula is tied to forecast gross customer additions and the unit cost is indexed to inflation. Growth capital will not be rebased during the Proposed MRP term but will be subject to true-up for actual gross customer additions at each Annual Review.

1.3.3.2 FEI Sustainment and Other Capital

FEI is seeking approval of the level of Sustainment and Other capital expenditures to be incorporated in rates over the term of the Proposed MRP.

Table A1-2 below summarizes the 2020-2024 forecast expenditures for Sustainment and Other capital. Details of the forecast Sustainment and Other capital expenditures are provided in Section C3.3.2 of the Application.

Table A1-2: FEI Sustainment and Other Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sustainment Capital	110,811	113,408	114,214	119,399	118,541	124,527
Other Capital	42,970	49,770	49,916	46,474	46,403	45,351
Total Capital	153,781	163,178	164,130	165,873	164,945	169,878

FEI has endeavored to maintain its Sustainment and Other capital spending increases at a level less than inflation over the course of the 2020-2024 term. Due to the timing and size of certain capital projects, fluctuations in capital spend from year to year are at times greater than inflation. However, the cumulative capital expenditure forecast from 2020-2024 as shown above represents less than annual inflationary increases over that term.

1.3.3.3 FBC Regular Capital

FBC is seeking approval of its forecast Regular capital expenditures over the term of the Proposed MRP.

Table A1-3 below summarizes the 2020-2024 forecast expenditures for Regular capital for FBC. Details of the forecast capital expenditures are provided in Section C3.4 of the Application.

Table A1-3: FBC Regular Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Growth Capital	$ 21,285	$ 27,029	$ 23,042	$ 24,339	$ 26,283	$ 23,170
Sustainment Capital	30,403	50,743	50,098	43,110	44,657	53,901
Other Capital	13,683	15,752	14,712	14,756	15,281	15,134
Total Regular Capital	65,371	93,524	87,853	82,205	86,220	92,204

Growth, Sustainment and Other capital expenditures for the 2020-2024 term are forecast to be higher than 2014-2019 expenditures. The primary drivers for the increase in capital expenditures are increased requirements for system improvements to accommodate load growth, upgrades to aging generation assets to meet current codes and standards, and equipment replacements necessary to address condition, aging infrastructure and improve reliability. Regulatory requirements and the need to address cyber threats also contribute to an increase in capital expenditures in comparison to previous spending levels.

1.3.4 Annual Calculation of the Revenue Requirement

As in the Current PBR Plans, FEI and FBC will calculate their respective revenue requirements and rates in each Annual Review during the term of the Proposed MRPs. Section C4 describes the cost and revenue items required to determine the Companies' annual revenue requirements, which will be included in each year's Annual Review materials.

As in the Current PBR Plans, FEI and FBC will forecast each year's delivery revenues (for FEI), revenue and power supply costs (for FBC), depreciation and amortization expense, property taxes, other revenue, interest expense, income tax, return on equity and rate base other than plant in service.

FortisBC proposes to continue with exogenous factors, such that customers' rates will be adjusted either up or down for the cost of service impacts of O&M and capital costs caused by exogenous factors that are beyond the control of the Companies. Exogenous factor treatment of such costs will ensure that customers pay only for the actual costs in circumstances where FortisBC does not control the level of expenditures. FortisBC continues to be of the view that there is no need for a materiality threshold for exogenous factors.

The Companies will also continue to include a forecast of O&M for items that are excluded from the O&M indexing. The following items will be forecast each year by the Companies, for inclusion in rates for the forecast year, subject to approval by the BCUC:

- Pension and Other Post Employment Benefits (OPEB) expenses, insurance premiums, and BCUC levies, consistent with the Current PBR Plans.
- FEI integrity digs: FEI proposes to treat the costs of integrity digs outside of the index-based O&M, as there is considerable uncertainty related to scope, cost, timing and volume of expected digs during the Proposed MRP term.
- O&M (and the cost of service of related capital expenditures) to support the Companies' investments in a clean growth future. This category currently consists of Natural Gas for Transportation (NGT) Stations, variable liquefied natural gas (LNG) production, Renewable Natural Gas (RNG), Electric Vehicle (EV) charging[4], but over the term of the Proposed MRPs either FEI or FBC may propose to include other initiatives in alignment with government policy; and
- Incremental costs to comply with legislatively mandated federal, provincial and municipal climate policy and with new Mandatory Reliability Standards (MRS). While the implications and associated costs to meet these and other draft requirements are

[4] Subject to the BCUC's determination in Phase 2 of the EV Inquiry.

currently being studied, the cost implications have not been accounted for in FortisBC's current operating or capital costs. FortisBC will bring forward its compliance plans and costs as the regulatory context becomes clear.

As in the Current PBR Plans, where variances are proposed to be flowed through in future revenue requirements, they will be captured in a single Flow-through deferral account, except where a previously approved deferral account already exists. FortisBC is proposing to align the manner in which FEI and FBC treat variances, where appropriate.

1.3.5 Deferral Accounts

FEI and FBC utilize both rate base and non-rate base deferral accounts to the benefit of customers and the utilities. Consistent with the BCUC's Regulatory Account Filing Checklist[5], FortisBC classifies its deferral accounts as one of forecast variance, rate smoothing, benefit matching, retroactive expense, or other deferral accounts.

The BCUC has indicated in the Decision accompanying Order G-7-03 that its Orders supporting deferral accounts continue in force until a change is approved by the BCUC. FEI and FBC will continue to use existing deferral accounts as approved, except as articulated in this Application.

Table A1-4 provides a summary of the request for approvals in this Application related to deferral accounts.

Table A1-4: Summary of Deferral Account Requests

Type of Change	Account	Company	Return requests	Additional requests
New Account	BCUC Levies Variance Account	FBC	Rate Base requested	Section C5.3.1.1; amortization period of 1 year commencing January 1, 2021.
	MRP Incentives Account	FEI & FBC	WACC requested	Section C5.3.2.1; amortization period of 1 year commencing January 1, 2021.
	Innovation Funding Account	FEI & FBC	WACC requested	Section C5.3.2.2; costs will be recovered through rider. Any residual balance will be addressed at the end of the term of the Proposed MRPs.
Other	Flow-through Account	FEI & FBC		Section C5.2.1; extend the use of this deferral account for the duration of the MRP period (2020-2024) and include items set out in Section C4.

A complete list of existing deferral accounts can be found in Appendix D1-1 for FEI and D1-2 for FBC.

5 BCUC Log 53608 dated May 3, 2017.

1.3.6 FortisBC Clean Growth Innovation Fund

Policy direction from all levels of government moving towards decarbonization creates an increased need for innovation and the adoption of new technologies. In this context, FortisBC has a clear vision for our future, as described in our submission to the Provincial government's recent CleanBC public consultation process:

> We believe that FortisBC has an important role to play in helping British Columbians 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, transportation [and industrial] sectors.[6]

To realize this vision, the Companies are proposing the creation of a Clean Growth Innovation Fund to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for our customers. The Clean Growth Innovation Fund will assist FortisBC in addressing the expectation to reduce emissions and support the transition to a lower carbon economy while maximizing the use of its energy delivery systems for the benefit of its customers.

Table A1-5 summarizes the main features of the Clean Growth Innovation Fund.

Table A1-5: Features of the Clean Growth Innovation Fund

Feature	Description
Responsive to climate policy	• Focuses on innovative activities that reduce greenhouse gas (GHG) emissions.
Responsive to customer expectations	• Focuses on bringing forward cost-effective energy solutions which reduce customer emissions.
Clear focus for innovative activities	• Complementary and incremental to current activities. • Both pre-commercial and commercial stages of commercialization. • Span entire utility value chain (supply, transmission & distribution, and end uses).
Predictable funding	• Monthly charge of $0.40 for FEI's and $0.30 for FBC's customers. Annually, $4.9 million for FEI and $0.5 million for FBC.
Robust framework	• Three stages to develop projects (identification, evaluation and selection and execution). • Senior management oversight and external advisory group. • Reporting in Annual Review process. • Unspent funds will be recorded in a deferral account and carried forward for the remaining term of the Proposed MRPs.

6 Appendix A5, page 2.

1.3.7 Service Quality Indicators

FortisBC believes the current suite of SQIs for FEI and FBC have been appropriate and useful in monitoring the Utilities' performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality. For the Proposed MRPs, FortisBC reviewed the current SQIs for their continued appropriateness in measuring service quality and for the level of the benchmarks and thresholds for each metric. Based on this review, FEI and FBC propose SQIs that build on the experience gained, with updates and modifications where required. FEI and FBC propose to replace the Informational Indicator of Telephone Abandonment Rate with another Informational Indicator, Average Speed of Answer. FBC also proposes to report on a new informational SQI, called "Interconnection Utilization", to measure the reliability of service for Wholesale Municipal customers.

1.3.7.1 FEI's Proposed Service Quality Indicators

For the Proposed MRP, FEI reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to our customers is maintained throughout the term of the Proposed MRP. FEI proposes to change the benchmarks of some SQIs, recognizing their recent historical performance. The following table provides a comparison of FEI's current and proposed SQIs. Proposed changes to SQIs are highlighted in green in the following table.

Table A1-6: Comparison of FEI Current and Proposed SQIs

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

			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
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

1.3.7.2 FBC's Proposed Service Quality Indicators

For the Proposed MRP, FBC reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to our customers is maintained throughout the term of the Proposed MRP. For some SQIs, FBC proposes to change their benchmarks and thresholds, recognizing their recent historical performance. The following table provides a comparison of FBC's current and proposed SQIs. Proposed changes to SQIs are highlighted in green in the following table.

Table A1-7: Comparison of FBC Current and Proposed SQIs

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

			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
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

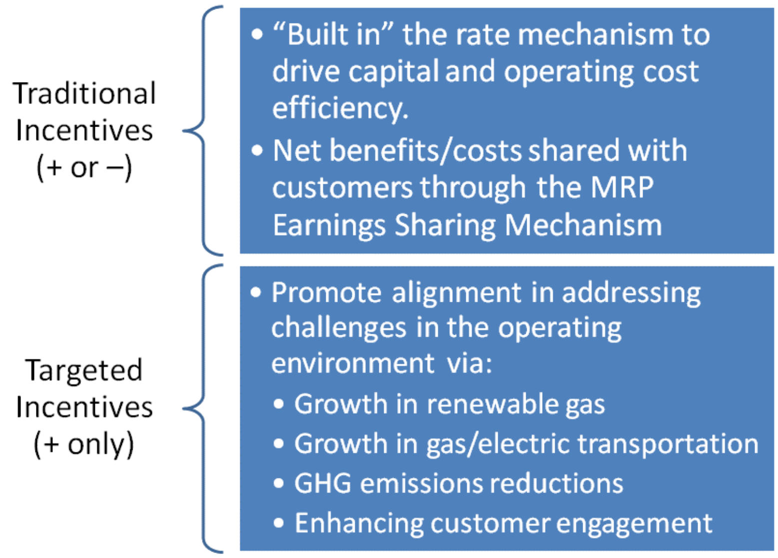
1.3.8 Incentives

The Current PBR Plans incorporate traditional PBR incentive mechanisms that have mainly focused on achieving cost efficiencies and reducing regulatory burden. While this focus led to cost savings for ratepayers, a more targeted approach is now needed to address the longer-term challenges and opportunities facing FortisBC. Regulators in other jurisdictions are increasingly recognizing the benefit of moving towards the inclusion of targeted incentives to promote innovative solutions to traditional utility challenges in their jurisdictions. FortisBC believes that adding a targeted approach that will foster innovation, and encourage the achievement of targeted incentives is appropriate and beneficial.

FortisBC will continue with traditional incentives that are inherent in index-based capital and operating costs and that have worked successfully in the past. However, FortisBC proposes adding targeted performance incentives that bring focus to addressing some of the challenges and opportunities in the operating environment.

Figure A1-3 below summarizes the different types of incentives for the Proposed MRPs.

Figure A1-3: Incentives for the Proposed MRPs



For the traditional incentives, FortisBC is returning to the widely-accepted method of calculating earnings sharing, which is a straight-forward percentage (in this case 50 percent) of variances from the allowed rate of return on equity. In this case, the regulated return on equity to which the earnings sharing applies excludes any targeted incentives. This simplified calculation provides greater transparency, increased simplicity in the design of the Proposed MRPs, and incentive and flexibility to implement capital plans efficiently.

FortisBC proposes a suite of targeted incentives focused on areas where success will benefit customers by advancing the adoption of cleaner, lower emissions energy solutions, contribute to the realization of energy and emissions goals, enhance customer engagement, and manage rate increases through growth in system throughput. The financial incentive for successful achievement of a target is an amount equivalent to additional basis points added to the Companies' allowed ROE. For simplicity, this amount is to be calculated outside of the Earnings Sharing Mechanism, as follows:

Targeted Incentive = Total Basis Points Achieved x Equity Portion of Approved Rate Base

An exception to this is the proposed Power Supply Incentive for FBC, which has its own basis for calculation. The Power Supply Incentive strengthens the alignment of interests between FBC and customers by providing an incentive for FBC to mitigate Power Purchase Expense. The proposed sharing mechanism applies to annual savings above $7.5 million, and is 90 percent to customers and 10 percent to FBC.

The targeted incentives are proposed as reward-only incentives. This design feature encourages FortisBC to expend effort towards achieving the targets within its O&M and capital funding constraints. Otherwise, a penalty for failing to achieve a targeted incentive could amount to a double penalty where the utility expends resources in pursuit of the incentive, but does not achieve it.

Another design feature of the targeted incentives is the addition of an MRP Target. The MRP Target provides an opportunity to evaluate overall performance and recognize the achievement of objectives on an overall basis. In other words, if the targets were missed in certain years, but the targets were achieved in aggregate, the Companies would earn the full incentive.

Table A1-8 below summarizes FortisBC's proposed targeted incentives**.**

Table A1-8: Targeted Incentives for the Proposed MRPs

Item	Applicable to	Opportunity	Proposed Incentive (equivalent basis points)
Growth in Renewable Gas	FEI	Incentive to exceed forecast renewable gas volumes	10 BPS
Growth in NGT	FEI	Incentive to exceed load growth forecast for transportation customers	10 BPS
GHG Emissions Reduction (Customer)	FEI	Incentive to exceed forecast natural gas conversion activity	5 BPS
GHG Emissions Reduction (Internal)	FEI	Incentive to reduce internal GHG emissions below targeted levels	5 BPS
Customer Engagement	FEI / FBC	Incentive to increase the adoption of digital service channels	5 BPS each
Growth in Electric Vehicle Transportation	FBC	Incentive to support the deployment of EV Charging infrastructure (subject to EV Inquiry)	5 BPS
Power Supply Incentive	FBC	Incentive to optimize power purchases	PSI calculated separately

1.4 *SUPPORTING STUDIES*

This Application seeks approval of updated versions of the various studies that will support the calculation of revenue requirements for the term of the Proposed MRPs.

1.4.1 Depreciation Studies

FortisBC is proposing updates to depreciation rates and net salvage rates for FEI and FBC based on the results of the depreciation studies for FEI and FBC included in Appendices D2-1 and D2-2, respectively (2017 Depreciation Studies).

For FEI, implementation of the 2017 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of Contributions in Aid of Construction (CIAC) rates, results in a net increase of aggregate depreciation and net salvage expense of approximately $3.5 million per year, a 0.08 percent overall increase to the composite depreciation rate compared to the current approved rates. The resulting increase to the delivery rate is less than one percent.

For FBC, implementation of the 2017 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, results in a net increase of aggregate depreciation and net salvage expense of approximately $2.2 million per year, an approximate 0.12 percent overall increase to the composite depreciation rate compared to the current approved rates. The resulting increase to rates is less than one percent.

1.4.2 Lead/Lag Studies

FortisBC is requesting approval to adopt updated lead-lag days as determined in the 2018 Lead-Lag Studies in Appendix D3-1 for FEI and Appendix D3-2 for FBC. In this Application FBC's lead/lag methodology has been modified to be consistent with the FEI methodology in order to achieve alignment across the FortisBC utilities.

The results for FEI are as follows:

- When applied to 2019 approved data, the 2018 Lead-Lag Study results in a net lag of 5.5 days. This compares to a net lag of 6.2 days, as shown in the FEI Annual Review for 2019 Delivery Rates – Compliance Filing filed with the BCUC January 30, 2019[7], which uses the 2009 lead-lag day study results.
- This difference of 0.7 days is the result of a 1.7 day increase in expenditure lead days, partially offset by a 1.0 day increase in revenue lag days. The increase in expenditure lead days is primarily attributable to a longer service lead for O&M expenditures and PST, partially offset by a shorter service lead for operating fees.
- When applied to the forecasted revenues and operating expenses for 2019, this change in net days would have resulted in a decrease of approximately $2.0 million in cash working capital ($4.8 million decrease from expenses partially offset by a $2.8 million increase from revenues).

The results for FBC are as follows:

- When applied to 2019 data, the 2018 Lead Lag Study results in a net lag of 9.5 days. This compares to a net lag of 6.7 days, as shown in the FBC Annual Review for 2019 Rates – Evidentiary Update[8], which uses the previous lead-lag day study results.
- This difference of 2.8 days is the result of a 3.4 day increase in revenue lag days, partially offset by a 0.6 day increase in expenditure lead days. The increase in revenue lag days is primarily due to an increase in lag days for sales revenue customers and increased lag days in apparatus and facilities rental revenue. This was partially offset by an increase in expenditure lead days primarily due to a longer payment lead for power purchases.

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7 Appendix A, Schedule 14, Line 26, Column 5.

8 Dated October 3, 2018, Exhibit B-2-2, Appendix A, Schedule 14, Line 38, Column 5.

- When applied to the forecasted revenues and operating expenses for 2019, this change in net days would have resulted in an increase of approximately $1.3 million in cash working capital ($1.6 million increase from revenues partially offset by a $0.3 million decrease from expenses).

1.4.3 Shared Services Study

FortisBC has reviewed its shared services model approach to cross charging between FEI and FBC, and proposes to allocate costs based on cost drivers (Cost Driver Approach), as opposed to the current approach of charging time between the Companies based on timesheets (Timesheet Approach). A Cost Driver Approach to allocating shared services costs between FEI and FBC is simpler to understand, easier to administer, more efficient, and more stable over time. The change in approach would have a minimal impact on FEI's and FBC's O&M costs.

Further details are provided in the Shared Services Study in Appendix D4.

1.4.4 Corporate Services Studies

FortisBC is requesting approval of the methodologies of allocating common corporate service costs from Fortis Inc. (FI) and FortisBC Holdings Inc. (FHI) to FEI and FBC. The allocation methodologies include a formula that is based on total assets, excluding goodwill, and controllable operating expenses for FI corporate services, and the use of a Massachusetts Formula for FHI corporate service allocations. Both methodologies and the nature of the FI and FHI corporate service costs were reviewed and endorsed by KPMG in the 2018 Corporate Service Study (2018 CS Study) included in Appendix D5. FortisBC is seeking approval of the allocation methodology, rather than the forecast of corporate service costs. The actual costs and allocation percentages will vary each year of the Proposed MRPs depending on the size of the eligible corporate cost pool at FI and FHI, as well as the relative size of the FI and FHI allocators.

The allocation of FI and FHI corporate service costs, including the addition of FBC to the sharing methodology, has been reviewed by KPMG in the 2018 CS Study. In Section 7.4 of the 2018 CS Study[9], KPMG states:

> 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.

FortisBC is requesting approval to apply the methodology of aggregating its common corporate service costs from FI and FHI and allocating them to FEI and FBC using the Massachusetts formula as described in detail in the 2018 CS Study.

[9] Appendix D5.

1.4.5 Capitalized Overhead Studies

FEI and FBC are proposing to apply capitalized overhead rates of 16 percent and 15 percent, respectively, of gross O&M to regular capital expenditures for the term of the Proposed MRPs. The capitalized overhead rates reflect a reasonable basis for capitalization of costs related to the increased capital activities, for both FEI and FBC, that have not been directly charged to capital projects. The allocation of capitalized overhead costs is consistent with the methodology from prior years' studies and filings, and corroborated with established rate-regulated utility practice, the BC's Uniform System of Accounts (USofA) and US Generally Accepted Accounting Principles (US GAAP).

The capitalized overhead rate of 16 percent for FEI was developed by KPMG, and reviewed and corroborated by management. KPMG's 2018 Capitalized Overhead Study for FEI is found in Appendix D6-1.

FEI estimates that the impact on delivery rates of a change to the capitalized overhead rate is approximately 0.1 percent for every 1.0 percent change in the capitalized overhead rate. Therefore, all else being equal, increasing the capitalized overhead rate from 12 percent to 16 percent decreases customer delivery rates by approximately 0.4 percent in the year of implementation.

The capitalized overhead rate of 15 percent for FBC was also developed by KPMG, and reviewed and corroborated by management. KPMG's 2018 Capitalized Overhead Study for FBC is found in Appendix D6-2. Given that FBC is not recommending a change in the capitalized overhead rate of 15 percent, there is no impact of FBC's proposal on customer rates.

1.5 CONCLUSION

FortisBC's Proposed MRPs should be approved by the BCUC. The Proposed MRPs provide a comprehensive and balanced rate setting framework for the Companies from 2020 to 2024 that provide the Companies with the flexibility to address challenges, opportunities and emerging pressures while continuing to provide safe and reliable service to customers.

2. APPROVALS SOUGHT

2.1 INTRODUCTION

In this Application, FEI and FBC are respectfully seeking an Order or Orders from the BCUC, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), granting the approvals set out in Sections A2.2 and A2.3, respectively. Draft forms of Order sought for FEI and FBC are included in Appendix E of the Application.

2.2 FEI APPROVALS

Proposed MRP Framework

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of this Application for setting delivery rates for the years 2020 through 2024, including:
   a) A five-year term 2020 to 2024 (Section C1.2);
   b) Use of an index-based approach to Base O&M and Growth capital, incorporating:
      i) A 2019 Base O&M per customer of $251, as described in Section C2.4, Table C2-1;
      ii) A 2019 Growth Capital per customer of $3,811, as described in Section C3.3.1, Table C3-3;
      iii) An inflation factor as set out in Section C1.3;
      iv) A forecast of customer growth as set out in Section C1.4;
      v) A true up of the spending envelope in the following year(s) as set out in Section C1.4;
   c) Approval of 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;
   d) Flow through treatment for the items described in Section C4 and Table C4-1;
   e) Exogenous factor treatment as described in Section C4.10;
   f) The 13 Service Quality Indicators (nine SQIs with a target benchmark and four informational measures) listed in Section C7.2, Table C7-1;
   g) Half of ROE variances before targeted incentives to be shared with customers as set out in Section C8.2;
   h) Targeted incentives as set out in Section C8.3, Table C8-1;

i) An efficiency carryover mechanism as described in Section C1.5;

j) Off ramps as described in Section C1.6; and

k) Annual review process as described in Section C1.7.

Deferral Accounts

2. Approval of the creation and modification of deferral accounts as set out in Section C5 of the Application and summarized in the following table effective January 1, 2020.

Table A2-1: FEI Proposed Deferral Account Changes

Type of Change	Account	Reference
New Account	MRP Incentives Account	Section C5.3.2.1, and Table C5-1 • Non-rate Base attracting a WACC return. • 1 year amortization commencing January 1, 2021.
	Innovation Funding Account	Section C5.3.2.2 and Table C5-1 • Non-rate Base attracting a WACC return. • Funding for this account collected through rate rider. Costs are charged to this account. • Any residual balance will be addressed at the end of the Proposed MRP term.
Other	Flow-through Deferral Account	Section C4 • Non-rate Base attracting a WACC return. • Extend the use of this deferral account for the duration of the Proposed MRP period and include items set out in Section C4.

Supporting Studies

3. Approvals of changes to the following supporting studies to be used in the determination of rates for FEI effective January 1, 2020:

   a. Modification to the approved Lead Lag days as set out in Table D3-1, Section D3.2;

   b. Depreciation rates in the amounts set out in Table D2-3 in Section D2;

   c. Net salvage rates in the amounts set out in Table D2-4 in Section D2; and

   d. The capitalized overhead rate of 16 percent as set out in Section D6.4.

4. Approval of 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.

Other Approvals for the term of the Proposed MRP

5. Approval of the Innovation Fund basic charge rate rider of $0.40 as described in Section C6.6, Table C6-3.

6. Approval to record 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.

2.3 *FBC APPROVALS*

Proposed MRP Framework

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of this Application for setting rates for the years 2020 through 2024, including:

   a) A five-year term 2020 to 2024 (Section C1.2);

   b) Use of an index-based approach to Base O&M, incorporating:

      i) A 2019 Base O&M per customer of $416, as described in Section C2.5, Table C2-14;

      ii) An inflation factor as set out in Section C1.3;

      iii) A forecast of customer growth as set out in Section C1.4;

      iv) A true up of the spending envelope in the following year(s) as set out in Section C1.4;

   c) Approval of 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;

   d) Flow through treatment for the items described in Section C4 and Table C4-1;

   e) Exogenous factor treatment as described in Section C4.10;

   f) The 12 Service Quality Indicators (8 SQIs with a target benchmark and 4 informational measures) listed in Section C7.3, Table C7-5;

   g) Half of ROE variances before targeted incentives to be shared with customers as set out in Section C8.2;

   h) Targeted incentives as set out in Section C8.3, Table C8-1;

   i) Efficiency carryover mechanism as described in Section C1.5;

   j) Off ramps as described in Section C1.6; and

   k) Annual review process as described in Section C1.7.

Deferral Accounts

2. Approval of the creation and modification of deferral accounts as set out in Section C5 and summarized in the following table effective January 1, 2020.

Table A2-2: FBC Proposed Deferral Account Changes

Type of Change	Account	Reference
New Account	BCUC Levies Variance Account	Section C5.3.1.1 • Rate Base. • 1 year amortization commencing January 1, 2021
	MRP Incentives Account	Section C5.3.2.1 • Non-rate base attracting a WACC return. • 1 year amortization commencing January 1, 2021.
	Innovation Funding Account	Section C5.3.2.2 • Non-rate base attracting a WACC return. • Costs recovered through rate rider. • Any residual balance will be addressed at the end of the Proposed MRP term.
Other	Flow-through Deferral Account	Section C4 • Non-rate base attracting a WACC return. • Extend the use of this deferral account for the duration of the Proposed MRP period and include items set out in Section C4.

Supporting Studies

3. Approvals of changes to the following supporting studies to be used in the determination of rates for FBC effective January 1, 2020:
   a. Modification to the approved Lead Lag days as set out in Table D3-2, Section D3.3;
   b. Depreciation rates in the amounts set out in Table D2-10 in Section D2;
   c. Net salvage rates in the amounts set out in Table D2-12 in Section D2; and
   d. The capitalized overhead rate of 15 percent as set out in Section D6.5.
4. Approval of 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.

Other Approvals

5. Approval of the Innovation Fund basic charge rate rider of $0.30 as described in Section C6.6, Table C6-3.

6. Approval of a Power Supply Incentive (PSI) as described in Section C8.3.7 and Appendix C7.

3. PROPOSED REGULATORY PROCESS

The Companies believe that this Application can be addressed efficiently and effectively by way of a written public hearing process and that if any aspects require further exploration, this can be accomplished by way of targeted workshops. In recognition that the BCUC will likely not be in a position to determine the appropriate regulatory process until after the first round of IRs, FortisBC's proposed draft preliminary regulatory timetable below provides for a workshop on key elements of the proposal, an initial round of IRs, and then a procedural conference to determine the rest of the regulatory process. The draft preliminary regulatory timetable proposed below seeks to recognize the workload required by the BCUC and all parties and in FortisBC's view will promote an efficient regulatory review process. The proposed timetable also takes into consideration the following:

- That the BCUC, interveners, and the Companies have six years of experience with the Current PBR Plans on which the Proposed MRPs are based;
- This Application is about setting the framework for the Proposed MRPs; there will be annual reviews each year of the Proposed MRPs to update most aspects of the Proposed MRPs to set rates each year;
- Many aspects of the Proposed MRPs are the same or similar to the Current PBR Plans;
- There has been a considerable amount of discussion with interveners and BCUC staff leading up to the submission of the Proposed MRPs; and
- Only certain aspects of the Proposed MRPs may require additional or more in-depth review.

The Companies' proposed draft regulatory timetable is set out below, which contemplates the BCUC issuing a procedural order on or before March 22.

Table A3-1: Proposed Regulatory Timetable

Action	Dates (2019)
FEI Publishes Notice	Week of April 8
Intervener Registration	Thursday, April 18
Workshop on Key Elements	Wednesday, May 1
BCUC 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

The proposed Workshop would include participation by the BCUC Panel and would cover key elements of the Proposed MRPs.

The Companies propose that the Procedural Conference address the following questions:

1. Whether a second round of IRs is required and, if so, on what aspects of the Application.
2. Whether interveners intend to file evidence and, if so, the nature and scope of that evidence, and the timing for filing such evidence.
3. Further process options for review of the Application, including:
   a. A negotiated settlement process;
   b. A written hearing;
   c. Workshops on areas that require further exploration;
   d. A streamlined review process;
   e. An oral public hearing; or
   f. A combination of processes, and the list of topics to be addressed by each of the processes.
4. Any significant time constraints and/or periods of unavailability which should be taken into consideration when establishing the regulatory timetable.

Following a Decision on this Application, which will determine the framework and specific elements of the Proposed MRPs, FEI and FBC will file their respective Annual Review materials for setting 2020 rates. Based on the timetable proposed above and depending on the remaining regulatory review process that is established following the Procedural Conference, it is unlikely that the Annual Reviews for 2020 rates will be completed in time to have permanent rates effective January 1, 2020. As such, FEI and FBC expect to seek approval of rates, on an interim basis, effective January 1, 2020, some time in the fourth quarter of 2019.

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Multi-Year Rate Plan for 2020 through 2024

Section B:

RATE PLAN CONSIDERATIONS

Table of Contents

B: RATE PLAN CONSIDERATIONS

1. OUR EVOLVING OPERATING ENVIRONMENT

1.1 INTRODUCTION AND SUMMARY

FortisBC's Proposed MRPs are designed to provide the Companies with the flexibility and incentive to address challenges and pursue opportunities presented by their operating environment. This section describes the key influences in FortisBC's operating environment, and the challenges and opportunities that these changes create.

Policy direction and mandate from all levels of government towards decarbonization:

In section 1.2, FortisBC describes how climate policy at all levels of government is focused on reducing emissions. The level of alignment between governments is indicative of a majority view in Canada, and a consensus in the scientific community, that addressing emissions is a key public interest. Given these realities, it is apparent that a transition to a lower carbon economy will occur and, indeed, has already begun. It follows that it is in the public interest for FortisBC to support this transition and adjust its business so that it can continue to serve its customers in a lower carbon future.

This alignment also brings new opportunities and challenges for FortisBC. FortisBC is an industry leader through its development of emissions-reducing solutions like RNG and NGT, efforts it has pursued for more than a decade. FortisBC's most recent response to its policy environment, the "Clean Growth Pathway to 2050" submission[10], represents an evolution of its innovative programs and outlines how FortisBC's infrastructure can contribute to achieving climate policy objectives at all levels. The pillars for the Clean Growth Pathway to 2050 include renewable gases, energy efficiency and innovation, transportation and reducing global GHG emissions. FortisBC believes its infrastructure will play a critical role in the transition toward a lower carbon environment.

Rising customer expectations with respect to service, engagement channels and keeping pace with other service providers:

In section 1.3, FortisBC describes how customer expectations are changing. Customers expect FortisBC to provide cost effective energy solutions and provide options to assist with meeting their environmental goals. In terms of interaction, customers are basing their expectations on interactions with non-traditional comparators. This drives the need to communicate with customers through new and innovative channels as well as provide leadership by helping customers reduce costs while offering cost effective and innovative energy solutions aimed at helping customers meet their energy needs.

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[10] Appendix A5.

Increased need for engagement with stakeholders and Indigenous communities as a result of stakeholder activism and provincial and federal policy changes:

In section 1.4, Fortis explains that it is increasing its focus on renewing and strengthening its Indigenous relationships, consistent with an increased commitment at the provincial and federal levels. The Companies will enhance their engagement practices including modernizing Indigenous operating arrangements and committing additional staff and resources to building capacity in Indigenous communities. This will assist in gaining vital support for required capital projects.

Similarly, engagement expectations across all stakeholder groups are increasing. As a result, FortisBC will expand its efforts on project consultation in terms of the scope and number of stakeholder and rights holder consultations. Maintaining and building positive relationships is vital to securing broad support and certainty for our future projects.

FortisBC will elevate its commitment to stakeholder engagement by working closely with and proactively educating key stakeholders on FortisBC's low carbon and renewable energy solutions. This interaction provides a valuable means for the Companies to assist their customers in developing and delivering low carbon and renewable energy solutions according to their unique needs and priorities. Consistent with this effort, the Companies will undertake broader communication to ensure customers and stakeholders are aware of FortisBC's activities and offerings.

Increased need for maintenance and investment in our aging infrastructure to continue to provide safe, reliable services along with increased need to provide for physical and cyber security:

As set out in section 1.5, FortisBC remains focused on delivering energy safely and reliably at the lowest reasonable cost. We work to ensure customer expectations are met by improving processes concerning the efficient and effective completion of work. FortisBC has experienced significant growth over the term of the Current PBR Plans, driving the need to invest in its energy infrastructure. In order to continue to deliver on its commitment to safety and reliability, FortisBC will seek increases in maintenance spending, consistent with its investment in both its new and aging infrastructure.

In response to increasing requirements for mobile computing, improved access to data, and increased activism, FortisBC will continue strengthening its physical and cyber security practices and systems.

Increased need for innovation and the adoption of new technologies to improve operations, enhance customer service levels and meet decarbonization policy objectives:

In section 1.6, FortisBC discusses how innovation and the adoption of technology is an important factor in the future growth of the Companies. Customers are increasingly looking to FortisBC to develop innovative solutions to address their changing energy needs. In response, FortisBC must increase its internal focus on innovation in an effort to continue to find better ways to meet customers' needs. This includes a continued pursuit of new technologies, which help drive greater efficiency, reduce costs and reduce emissions. Not only is innovation and the adoption of new technology an important part of meeting changing customer energy needs, but it also contributes to meeting climate objectives while having the potential to reduce rate pressures into the future.

1.2 *ENVIRONMENTAL POLICY AND FORTISBC'S RESPONSE*

Today's energy policy agenda is increasingly characterized by reducing GHG emissions and transitioning toward a low carbon economy. Over the past three years, all levels of government (federal, provincial and local) have increased the stringency of policies to reduce GHG emissions. Policy tools including carbon pricing, codes and standards, electrification and switching to lower carbon and renewable fuels, are expected to play a central role in meeting Canada's and B.C.'s GHG emissions targets. The basic objective of these policies is to reduce emissions; however, this transition will require investment in energy efficiency and conservation, renewable energy supply, and other low carbon energy initiatives including using NGT, EV and LNG for export and domestic use.

The level of alignment between governments is indicative of a majority view in Canada, and a consensus in the scientific community, that addressing emissions is a key public interest. Given these realities, it is apparent that a transition to a lower carbon economy will occur and, indeed, has already begun. It follows that it is in the public interest for FortisBC to support this transition and adjust its business so that it can continue to serve its customers in a lower carbon future.

The following sections discuss environmental policy initiatives at the federal, provincial and local government levels, including the (1) Federal Pan-Canadian Framework on Clean Growth and Climate Change, (2) the CleanBC Plan, (3) the BC Energy Step Code and other local government initiatives, and (4) other internal emissions regulations. FortisBC then summarizes its response to government policy in its long-term resources plans, and the Clean Growth Pathway.

1.2.1 Pan-Canadian Framework on Clean Growth and Climate Change

The Pan-Canadian Framework on Clean Growth and Climate Change (the Pan-Canadian Framework), published in October 2016, is the federal government's climate policy framework. The Pan-Canadian Framework is underpinned by a number of key regulatory measures including:

- The federal carbon pricing backstop to ensure a minimum price on GHG emissions effective in 2019;
- The Clean Fuel Standard to reduce the lifecycle carbon intensity of liquid, gaseous and solid fossil fuels consumed in buildings, transportation and industry by 2022 (for liquid fuels) and by 2023 (for gaseous and solid fuels);

- Developing increasingly stringent net zero energy building codes for new buildings in 2020 and for existing buildings by 2022; and
- Fugitive methane regulations aimed at reducing emissions by 40 to 45 percent by 2025.

The Clean Fuel Standard is expected to achieve the largest GHG emissions reductions of any federal policy by 2030 at 30 million tonnes (Mt) of GHG reductions compared to business as usual. The Clean Fuel Standard is organized along three fuel streams - liquids, gaseous, and solids. The gaseous stream will regulate upstream natural gas processors and gas distribution utilities across Canada to reduce the lifecycle carbon intensity of the gas that is delivered for domestic use. The Clean Fuel Standard is designed to allow multiple compliance pathways whereby regulated entities must hold the required amount of emissions reductions credits to meet their annual obligation. Credits can be generated by investing in actions that reduce carbon intensity or they can be purchased through the credit market from other credit generating entities. Using a policy mechanism of this type in the natural gas sector will be a global first and will likely require significant learning and flexibility from all key stakeholders in the gas sector. The details of the Clean Fuel Standard are currently being developed and the specific impact to FortisBC and its customers is a significant unknown.

1.2.2 CleanBC Plan

At the provincial level, the B.C. government is committed to meeting the province's climate goals and has introduced legislated GHG reduction targets of 40 percent below 2007 levels by 2030, 60 percent by 2040, and 80 percent by 2050. To achieve these targets, the provincial government released the CleanBC plan (CleanBC) late in 2018, which outlines the priority areas for GHG reduction and the actions it will take. The provincial government is also increasing the economy-wide carbon tax to drive emissions reductions. The provincial carbon tax currently sits at $35 per tonne ($1.74 per gigajoule or GJ) and will increase to $40 per tonne ($2.00 per GJ) on April 1, 2019. The tax will continue to increase annually until it reaches $50 per tonne ($2.50 per GJ) in 2021. The increase in the tax, as well as measures to reduce methane emissions and electrify upstream natural gas production, will put upward pressure on the cost of natural gas for FEI's customers.

CleanBC takes a sector-specific approach to achieve GHG reductions. Actions in the plan achieve 75 percent of the emissions reductions (18.9 Mt) required to achieve the 2030 reduction target of 25 Mt. Actions in the plan fall under the following themes:

- Cleaner transportation;
- Improving the built environment; and
- Cleaner industry.

1.2.2.1 Cleaner Transportation

Actions in cleaner transportation focus on accelerating the use of cleaner fuels. The existing Renewable and Low Carbon Fuel Requirement Regulation (RLCFRR) will be updated and strengthened to achieve a 20 percent reduction in the average carbon intensity of transport fuels by 2030. This will provide additional incentives for lower carbon fuels such as compressed or liquefied natural gas and RNG. A zero-emission vehicle (ZEV) mandate will require 10 percent of new passenger vehicle sales to be zero emissions by 2025, 30 percent by 2030 and 100 percent by 2040. CleanBC will also expand incentives for clean buses and medium and heavy-duty vehicles, which will drive more investment in clean fuelling infrastructure for electric, gas and hydrogen vehicles. Along with an initiative to promote cleaner trade corridors and ports, CleanBC points to the important role of FortisBC's low carbon transportation offerings, which will need additional funding to sustain and grow the programs.

1.2.2.2 Improving the Built Environment

A central component of the buildings-focused segment of CleanBC is a 15 percent renewable gas target for the province. Of the actions identified for buildings, the renewable gas target achieves 75 percent (1.5 Mt) of the total emission reductions in the sector. This makes the gas system a central component of the provincial strategy to reduce GHG emissions in buildings. The strategy commits to ambitious organic waste diversion and landfill capture targets which may be leveraged as a low cost resource to decarbonize B.C.'s natural gas stream. In addition, the provincial government aims to accelerate B.C.'s hydrogen economy through support for natural gas grid injection and fuel cell electric vehicles and infrastructure. To meet this target, FEI will need to escalate its investment in RNG and hydrogen infrastructure along with research and development (R&D), piloting, and demonstration. Additional regulatory support, education and engagement of gas system stakeholders in the development of renewable gas resources will also be essential.

CleanBC will also expand energy efficiency improvements and electrification of buildings by fuel switching from natural gas appliances to electric heat pumps. All new buildings built by 2032 will be "net-zero energy ready". CleanBC also states that 70,000 homes and 10 million m^2 of commercial space will be retrofitted with electric heating, and that by 2030, 60 percent of homes and 40 percent of commercial buildings will use clean electricity, whereas today a majority of homes and businesses are heated with natural gas. Collectively, these actions represent a significant challenge to natural gas demand in the buildings sector. However, combined with the emphasis on renewable gas, they also provide impetus for FEI to explore opportunities to bring innovative solutions to buildings such as renewable gas (RG)[11], natural gas heat pumps and advanced metering infrastructure (AMI) for gas customers.

[11] "Renewable gas" describes a broader range of renewable gas solutions from traditional renewable natural gas generated from organic waste sources to other sources such as hydrogen gas.

1.2.2.3 Cleaner Industry

In industry, the provincial government will provide capital funding drawn from carbon tax receipts from industry for GHG emissions saving projects. The other priority area will be to electrify natural gas extraction and processing in North Eastern BC. Funding for emissions savings projects could boost FortisBC's Demand Side Management (DSM) program offerings for industry and open other options for FortisBC to invest. The 15 percent renewable gas target is also expected to reduce industrial GHG emissions by 0.9 Mt.

The provincial government will develop additional initiatives, which will be introduced over the next two years, particularly in the area of heavy duty and marine vessels, to make up the remaining 25 percent (6.1 Mt) of GHG reductions required to achieve the 2030 target.

1.2.3 BC Energy Step Code and Other Local Government Initiatives

To provide municipalities with tools to increase the efficiency of new buildings, the BC Energy Step Code (Step Code) gives local governments the ability to require or incentivize new building construction to go beyond the requirements of B.C.'s Building Code. To date, 14 local governments now reference the Step Code in policy, programs or bylaws, and an additional 21 local governments are in the consultation stages of adoption. At higher levels of the Step Code it will be more challenging for buildings to use traditional natural gas equipment, but this may also open up opportunities for increased use of RG/RNG and new and innovative natural gas equipment.

A small number of local governments have taken the City of Vancouver's (CoV) approach in adopting 100 percent renewable energy by 2050 targets. The Cities of Victoria and Nelson, along with the District of Saanich, are currently examining strategies to fully decarbonize heating, cooling and transportation networks by 2050. At the same time, other local governments including the City of Richmond and Capital Regional District have followed the CoV's lead in passing a motion to declare a climate emergency. These motions lay the groundwork to strengthen local governments' climate action plans, accelerate emissions targets, and add new actions to reduce the cities' GHG emissions. Such aggressive energy policies can ultimately constrain the outlook for FEI's traditional natural gas services in these jurisdictions.

1.2.4 Other Internal Emissions Regulations

Policy direction with respect to energy and air emissions management regulation continues to unfold, but it remains to be determined to what extent upcoming regulatory changes will impact FortisBC. On December 17, 2018, the BC Oil and Gas Commission (BC OGC) published draft amendments to the Drilling and Production Regulation (B.C. Reg. 282/2010) to include requirements intended to reduce methane emissions from upstream oil and gas operations. The scope of these amendments may include all BC OGC regulated facilities such as FEI's compressor and LNG stations. The amendments include specific limits and/or requirements associated with compressor seal venting, storage tanks, pneumatic devices, and equipment leaks.

As a result of these and other regulations focused on internal emissions reductions, FortisBC is working to research, prioritize and perform comparative assessments of the most viable internal GHG emission reduction projects for the business. While the implications and associated costs to meet these and other draft requirements are currently being studied, the cost implications have not been accounted for in this Application. FortisBC will bring forward its compliance plans and costs as the regulatory context becomes clear.[12]

1.2.5 Environmental Policy and Our Long Term Resource Plans

Under section 44.1 of the UCA, the Companies file long term resource plans at regular intervals. FBC's 2016 Long Term Electric Resource Plan (LTERP) and FEI's 2017 Long Term Gas Resource Plan (LTGRP) are the Companies' most recently submitted resource plans.

The 2017 LTGRP contains a vision for FEI in 20 years (Section 8: 20-Year Vision for FEI). Alongside Appendix E of the 2017 LTGRP, which discusses potential GHG emissions reduction pathways, this section highlights the sizable role (up to 21.3 million tonnes of carbon dioxide (CO_2) equivalent emissions reductions)[13] of pursuing new carbon reduction opportunities. If such opportunities become commercially scalable at reasonable cost, they may mitigate policy-driven risks of downward pressure on natural gas demand.[14] Investment in such opportunities may cause upward pressure on FEI's rates but such upward pressure may be offset by maintaining or increasing delivered energy amounts via these same or other activities. The beneficial impact of NGT on projected delivery rates discussed in the 2017 LTGRP's 20-Year Vision for FEI illustrates this effect: the analysis shows a cumulative reduction of rate pressure by 12 to 25 percentage points over a 20-year planning horizon.[15] In contrast, reducing energy amounts delivered by FEI's infrastructure in order to achieve GHG emissions abatement would cause upward pressure on rates without any compensating effect.

Similarly, the 2016 LTERP recognizes that climate and energy policy, emerging technologies and changes in how customers use and provide energy could impact FBC's 20-year load and resource analysis. The 2016 LTERP finds that the two emerging load drivers that may have the most impact to FBC going forward are EVs and distributed generation (DG) via residential rooftop solar photovoltaics (PV).[16] Increased consumer adoption of EVs in BC, with their associated energy and demand charging requirements, has the potential to place significantly greater demands on utility infrastructure. However, depending on customers' charging strategies, there is opportunity for these types of loads to improve the utilization of the electric grid without significantly impacting FBC's infrastructure.[17] FBC's continued involvement in supporting transportation electrification will help to ensure the development of a robust EV charging network that appropriately takes into consideration the growing number of EVs and supports government goals for reducing GHG emissions from the transportation sector.

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[12] See Section C4.4.
[13] FEI 2017 LTGRP, Table E-1, Appendix E, p. 7.
[14] FEI 2017 LTGRP, Section 8.2.4, p. 201.
[15] FEI 2017 LTGRP, Section 8.6, pp. 211-212.
[16] FBC 2016 LTERP, Section 4.4, p. 73.
[17] FBC 2016 LTERP, Section 2.3.2, p. 26.

Further study into DG will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system. DG facilities could provide value if they are able to generate electricity during peak demand times. This is beneficial because it could reduce the need for FBC to purchase energy from the British Columbia Hydro and Power Authority (BC Hydro) or other parties and decrease transmission line congestion. By meeting customer electricity needs closer to the point of consumption, DG facilities could reduce FBC incremental resource requirements and reduce loading on distribution and transmission lines. However, for DG systems to operate in this way, they must be interconnected, controlled, measured and operated as an integral part of the FBC electricity system.[18]

1.2.6 FortisBC's Clean Growth Pathway

As part of the development of the province's climate action goals, British Columbians were asked for their feedback. As the largest energy supplier in B.C. and an integrated gas and electric utility, FortisBC brings a critical perspective on the provincial energy system and opportunities to reduce GHG emissions. FortisBC engaged with staff across the organization to develop our response – the Clean Growth Pathway to 2050. Our recommendations fall under four pillars as summarized below.

1.2.6.1 Renewable Gases are Critical for GHG Reduction Objectives

Using the province's existing gas infrastructure is critical to meeting its GHG reduction objectives. As FortisBC states in its Clean Growth Pathway document:

> 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.[19]

Thus, the provincial strategy has recognized the key role of renewable gases and the gas system through its inclusion of a 15 percent renewable gas target. This strategy takes advantage of FEI's multi-billion dollar, safe, reliable and province-wide distribution system to deliver lower-carbon gas (via drop-in RNG or hydrogen), which supports customers' access to a cost effective means to achieve their sustainability goals.

[18] FBC 2016 Long Term Electric Resource Plan, Section 6.4.1, pp. 89-90.
[19] Appendix A5. Clean Growth Pathway to 2050. Page 13.

1.2.6.2 Energy Efficiency and Innovation in Buildings

As a supporter of Step Code targets, we support consistent codes and standards throughout B.C., while allowing consumers to choose their method of heating. Our recommendation was to continue to maintain the current focus on energy efficiency by committing to the Step Code, and to align it to future national building codes. FortisBC is a leader in energy efficiency and our DSM applications support our commitment to increase energy efficiency programs.

1.2.6.3 Transportation Investments to Reduce GHG Emissions and Improve Air Quality

Transportation currently accounts for 39 per cent of the province's carbon emissions, as well as using (for the most part) non-renewable energy sources, so it's logical for the province to prioritize the transportation sector for the bulk of GHG emissions reductions. FortisBC sees that it has an important role to play in the transportation area, such as growing electric vehicle charging infrastructure and our NGT program. The NGT program not only reduces GHG emissions but also local air pollution; it could significantly improve quality of life for communities with heavy truck traffic, such as near port terminals.

The international marine transportation sector contributes more than 70 million metric tonnes of CO_2 equivalent (CO_2e) per year when in transit and berthed in B.C. ports – an amount greater than B.C.'s total annual emissions.[20] LNG will be critical to addressing emissions and air pollutants from this segment.

1.2.6.4 Reducing Global GHG Emissions with Clean LNG

Climate change is a global problem, and some of the most important GHG reduction potential resides in countries still dependent on coal. By shipping LNG to customers around the world, FEI can help lower emissions in other countries. Our resources provide one of the cleanest forms of LNG in the world.

1.3 CUSTOMER EXPECTATIONS

FEI's operating environment is shaped by evolving customer expectations, from both a service delivery standpoint as well as customers' attitudes and preferences towards energy solutions. Changes in customer expectations and behaviour, as well as available technologies, require the Companies to regularly evaluate the services provided to our customers and consider opportunities to deliver on customer expectations.

As set out below, FEI's and FBC's customer engagement in its long-term resource plans shows that customers depend on FortisBC to deliver energy services safely and reliably not just in the short term but also across longer planning horizons. Customers have expectations related to FortisBC's service orientation, i.e. making it easy, and providing information proactively, but also

[20] Appendix A5, page 8.

have environmentally focused expectations related to FortisBC's stewardship, leadership and accountability. Thus, FortisBC must continue to act as a leader in providing cost effective, convenient energy solutions as well as options to assist customers with meeting their environmental goals. FortisBC is doing this by responding to changing expectations related to how it interacts with its customers and continuing to meet strong demand for its services, including expanding its offerings to customers in the transportation sector.

1.3.1 Customer Engagement in our Long Term Resource Plans

When preparing long term resource plans, the Companies scan the environment and conduct stakeholder engagement activities to gather input from representatives of residential, commercial, and industrial customers as well as environmental organizations and communities across BC. Some of these stakeholders also regularly intervene in the Companies' regulatory proceedings.

As noted in the 2017 LTGRP, FEI's long-term vision is to be BC's trusted energy provider for safe, reliable and cost effective energy delivery and to be a healthy and growing contributor to the BC economy and to the well-being of communities in BC.[21] FEI understands its customers' expectations for cost effective energy and is well positioned to identify short and long-term opportunities for innovation that will support environmental policy and customer goals while enabling FEI to continue operating in an economically sustainable fashion in the long term.

FEI's pursuit of innovation and growth to support clean and cost effective energy solutions is consistent with FEI's LTGRP analysis and the feedback received during the associated stakeholder engagement process. Throughout this process, customers and stakeholders considered and expressed support for FEI to pursue regulatory allowances that enhance its ability to have a positive impact on energy use patterns and GHG emissions within the evolving operating environment.[22] During the LTGRP community engagement process, FEI's customers and stakeholders reinforced this notion by highlighting that energy and emissions policy (with persistently evolving regulations and technology opportunities) fall outside their core competence or their direct sphere of influence. As such, FEI's customers and stakeholders seek to rely on FEI to provide energy solutions that help meet both their operational and budgetary requirements as well as energy and emissions policy targets at predictable prices.[23,24]

The 2016 LTERP engagement activities reveal similar customer and stakeholder expectations. These include continuing to receive reliable electricity supply and access to initiatives that help customers and communities to manage energy costs while also finding solutions to reduce GHG

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21 FEI 2017 Long Term Gas Resource Plan, Section 8, p. 196.
22 FEI 2017 Long Term Gas Resource Plan, Section 9, pp. 219-220.
23 Institutional customers, municipalities and small businesses, in particular, expressed this sentiment.
24 For example, expressed in FEI's Resource Planning Community Engagement workshops in: New Westminster (May 2, 2017), https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/meeting_notes_new_westminster.pdf; and Courtenay (May 17, 2017), https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/meeting_notes_courtenay.pdf.

emissions. Participants in the 2016 LTERP engagement process also expressed preferences for more education resources regarding energy savings and new technologies.[25]

1.3.2 Evolving the Customer Experience

Enhancing the customer experience remains a key priority for the Companies now and in the upcoming years. Customers' expectations for service have changed and are expected to keep changing based on improvements and access to technology and experiences with other service providers.

Today, our customers value ease of interaction, convenience, and responsiveness, and they expect proactive communication from the utility to allow for informed choice. This is a notably different environment than the recent past when customer engagement was traditionally on the utility's terms and on a transactional basis, for example when a customer paid a bill or requested service.

Customers today are receiving a high level of service through well-functioning service channels, and FortisBC is equipped with reliable technology infrastructure and a workforce that is adaptable and focused on meeting customer needs. FortisBC has approximately one million interactions with customers and processes over 11 million bills on an annual basis. The reasons for these interactions include account inquiries, new accounts, moved accounts, payment inquiries, collections, meter exchange appointments, usage and conservation information, available rebates, new service attachments and billing services and support. Methods of interaction are both phone and web-based.

However, technology is evolving rapidly, and customer expectations regarding their customer experience continues to evolve. Over time, the influences of a younger customer base and workforce will impact our customers' expectations and the skills of our staff. Expectations of the Companies' workforce are also evolving, with the work shifting from traditional utility business to supporting expanding service offerings. Further improvements in automation, data analytics and customer engagement tools will enhance the Companies' ability to meet the changing needs of customers and deliver on key business priorities.

Adding to the changing landscape is that the definition of our customer is changing. Historically, the utilities have served core residential, commercial and industrial natural gas and electricity customers. As we evolve our business, the boundaries and definition of our "customer" broadens to other sectors. As a result, we must interact with a larger, broader set of external influencers in order to continue to be successful in adding customers and volume to our systems. Over time, the complexity of our interactions with customers is set to increase, and the number of methods we use to interact with customers will also increase and evolve, which has implications not only for the way that we operate, but also for the skill sets that are required.

Customer communications is another area that has been changing rapidly over the past five years. The proliferation of digital media sources is changing the nature of customer outreach

[25] FBC 2016 Long Term Electric Resource Plan, Section 10, p. 136.

from one-way to two-way communication channels and multi-voice platforms. Changing customer preferences provides an opportunity to leverage technology and connect with customers at a different level. Interactions through non-traditional channels - such as text messaging, mobile applications and social media - offer a means to engage the customer more closely in order to continue to strengthen the relationship with FortisBC. At the same time, the Companies must continue to communicate through more traditional means such as regional and local newspapers to reach all segments of our customer base.

It is essential that FortisBC be well positioned to adopt innovative approaches to engaging customers. Adopting new solutions in order to meet and maintain existing service level standards as well as meet customer expectations now and into the future is a requirement.

Some of the ways the Companies have been doing this for our natural gas and electricity customers are:

- Making interactions low effort for our customers by offering a variety of channels for contact and emphasizing first contact resolution;
- Taking a customer-centric approach to collections;
- Commencing a bill redesign project focusing on increased customer engagement;
- Designing a customer engagement tool that will give customers access to various energy usage reports;
- Providing for 24-hour telephone coverage for electric outages; and
- Giving customers the opportunity to participate on the MyVoice research panel[26], providing input on various customer initiatives.

FortisBC will continue to improve customer engagement through initiatives such as increasing the ways in which customers can interact with FortisBC, and by re-designing customer bills from being focused on the accounting transaction to focus on helping customers understand and control their energy use.

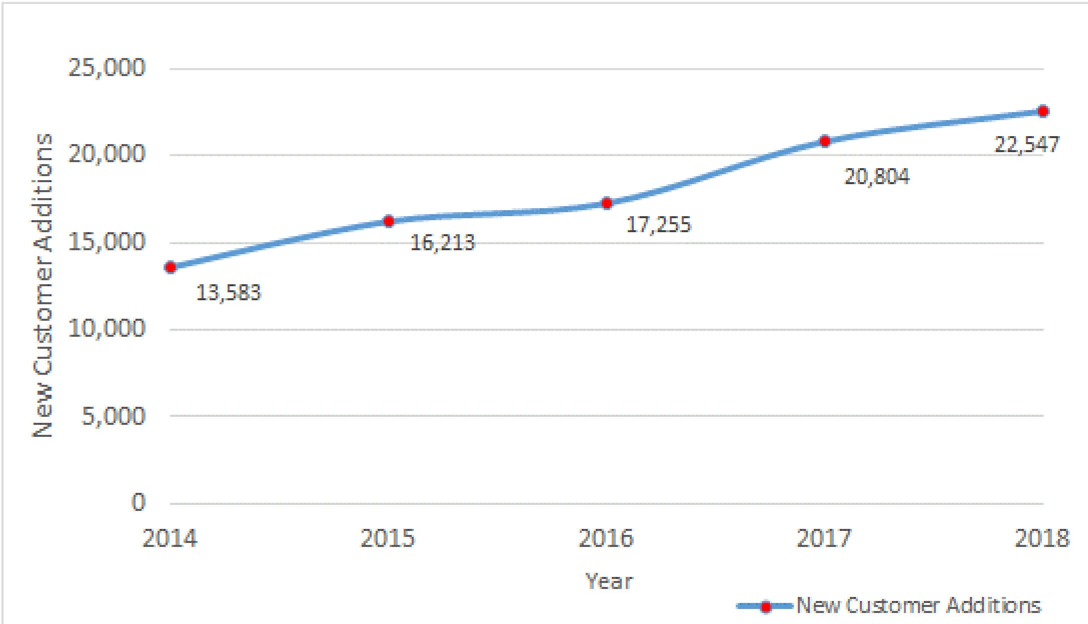
1.3.3 Providing Cost Effective Energy Solutions

Providing cost effective, accessible and innovative energy solutions that British Columbians are seeking is a cornerstone of our focus.

FEI has seen year over year increases in new gas customer attachments since the beginning of the Current PBR Plan. Annual attachments increased from approximately 13,500 in 2014 to over 22,500 in 2018. In total, FEI attached approximately 90,400 customers to the distribution system between 2014 and 2018.

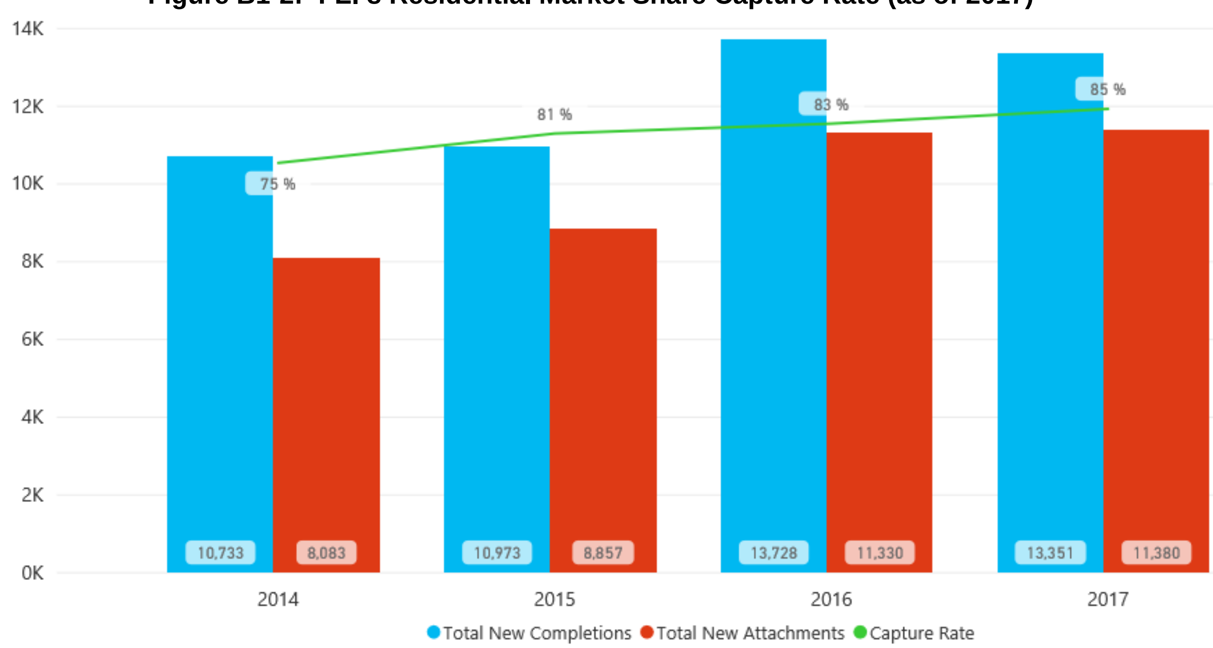
[26] MyVoice is an online community of approximately 2600 self-enrolled FortisBC customers who are available to give rapid and ongoing feedback to questions posed. The community helps inform FortisBC business considerations by facilitating ongoing, two-way dialogue that complements other data sources and research.

Figure B1-1: FEI Customer Attachments



The increase in customer attachments is partly due to a corresponding increase in new housing starts and completions in the province. In addition, and as demonstrated by the graph below, FEI's market share of new residential construction projects choosing natural gas has been increasing through efforts in gaining a greater share of the new construction market.

Figure B1-2: FEI's Residential Market Share Capture Rate (as of 2017)[27]



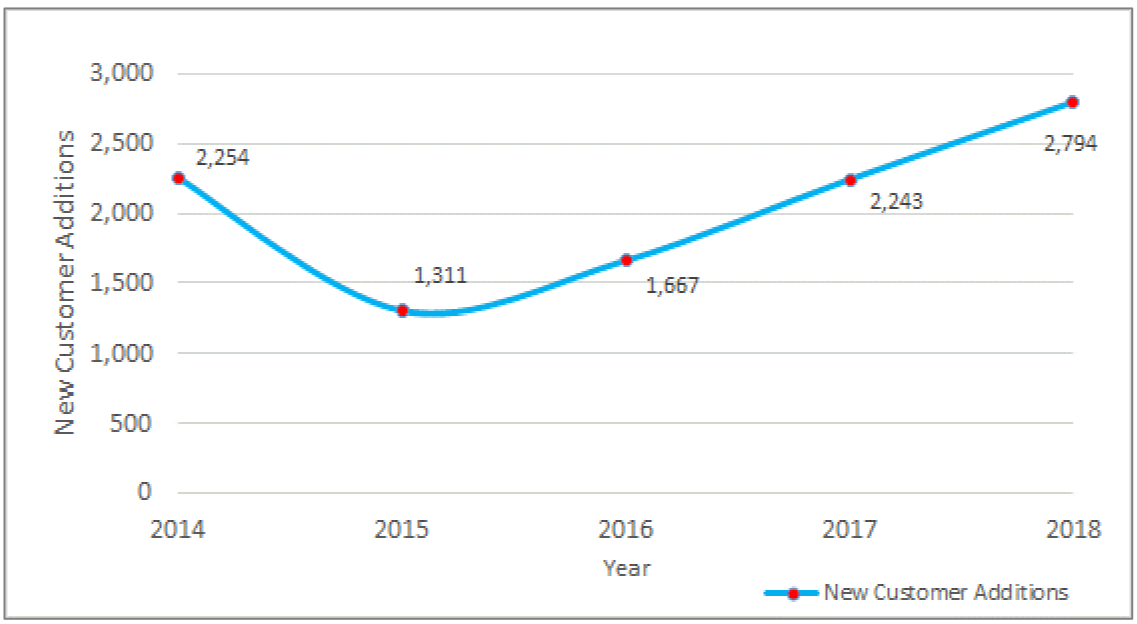
[27] Municipalities not served by FortisBC are excluded. Condominium buildings (not condominium units) are included in the capture rate calculation.

Natural gas continues to play a pivotal role in heating B.C.'s homes, as the increasing cost of living in the province elevates affordability concerns.

FEI invests significant effort in encouraging new customers to connect to the natural gas system and to keep existing customers attached. Employees actively work to attract and retain customers, as FEI recognizes that it takes concerted effort and active engagement to influence customer decisions to adopt natural gas. FEI works closely with customers, developers, builders, architects, engineers and HVAC contractors to demonstrate the value of using natural gas and to familiarize them with new products and appliances. FEI also works to make businesses more efficient by encouraging the efficient use of natural gas. By working collaboratively with customers, builders, developers, and contactors, FEI has been able to deliver and advocate for programs and services that are important for our customers.

For FBC, recent growth has also been strong. Over the past five years, FBC has added 10,269 customers, representing growth of approximately 1.5 percent annually, and in 2018, FBC added 2,794 customers representing growth of approximately 2.0 percent.

Figure B1-3: FBC Customer Attachments



Continued customer growth is vital to keeping rates affordable for both gas and electric utilities.

1.3.4 Customer Offerings in Transportation

FortisBC is continuing to expand its offerings to customers by pursuing load growth opportunities in the transportation sector. In addition to providing opportunities for fuel savings for operators of natural gas and electric vehicles, demand for NGT and EVs is being driven by government policy related to GHG and air emissions and by advancements in technology.

1.3.4.1 Natural Gas for Transportation

For the operator of a medium-duty or heavy-duty vehicle fleet, adopting NGT means making a change to natural gas from a fuel, typically diesel, that fleet operators have used for many years. There is a perception amongst many fleet operators that the risk associated with making a fuel change is significant. For that reason, FEI offers multiple elements of support for its NGT customers: vehicle capital incentives, the provision of fueling infrastructure, driver and mechanic training, maintenance facilities upgrades and marketing support, and will continue to need to do so.

FEI also continues to be focused on facilitating the adoption of LNG as a marine fuel, and has had success in the ferry segment of this market. Generally, the marine sector includes a small number of large customers that are well resourced in comparison to the majority of the on-road customer base. FEI's existing customers for marine LNG have been vocal about benefits they have enjoyed by adopting LNG. Finally, the International Maritime Organization has introduced regulation that supports the adoption of LNG by operators of marine vessels. FEI believes that there is significant opportunity for greater adoption of LNG in the marine sector.

1.3.4.2 Electric Vehicles

While the Electric Vehicle Charging Inquiry provides some uncertainty over FBC's role in supporting EV charging, FBC believes it has an important role to play in the deployment of Direct Current Fast Chargers (DCFC) to support high-speed charging in transportation corridors. In addition, FBC plans to design programs for home and business-based charging that will consider the impacts of the increased load on the electric distribution grid. FBC will also develop a program to assist multi-family residential customers in adopting EV charging where their dwellings do not easily support dedicated chargers.

1.4 *STAKEHOLDER ENGAGEMENT AND INDIGENOUS RELATIONS*

The expectations on FortisBC for public consultation and engagement are growing increasingly higher. Government requirements for stakeholder consultation and engagement with Indigenous communities are becoming increasingly more involved and complex. With a low level of public awareness and involvement in energy decisions, there is an opportunity to provide leadership and education on how the natural gas and electric distribution systems can play an active role in shifting B.C. to a lower carbon economy, especially through FortisBC's renewable and low carbon energy products and services.

The risks of failing to adequately engage are many, and include:

- Increased costs for customers resulting from policies and regulations placing increased pressure on natural gas use;
- Increased opposition to FortisBC's projects, resulting in higher costs for customers;
- Lack of understanding of FortisBC's energy products and services;

- Lack of understanding of the benefits of FortisBC's products and services and how they can cost-effectively progress B.C. toward meeting its climate action goals;
- Lack of recognition of the broad economic benefits inherent in the cost effective energy delivered by FortisBC; and
- Upward pressure on customer rates from declining throughput on the gas system.

As such, FortisBC plans to increase engagement with government and other stakeholders so that customers' interests are considered in policy planning and regulatory developments. The Companies need to educate and engage on the benefits that FortisBC's infrastructure and services provide both in helping to meet B.C.'s climate action goals and in supplying the province with cost effective energy which drives broader economic benefits.

1.4.1 Expanding Indigenous Relations Efforts

In 2018, both the federal and provincial governments made public declarations to support Indigenous Reconciliation and the implementation of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP). More recently, the provincial government announced its intention to introduce legislation to implement UNDRIP, which will make B.C. the first province in Canada to legislate its endorsement of the declaration. As a result, FortisBC, in turn, will also need to commit incremental resources toward renewing and strengthening Indigenous relationships, particularly with respect to access to land. Few treaties have been signed in B.C., creating legal uncertainty over rights and title to land. Considering that much of FortisBC infrastructure crosses traditional Indigenous territory, Indigenous relationships are critical to successfully advancing the Companies' capital infrastructure projects.

The Companies have a strong record of building effective relationships with Indigenous communities through proactive engagement, procurement, employment practices and partnering on investment. Additional work is required to further enhance the Companies' engagement, modernize Indigenous operating arrangements and commit additional resources and investments to build capacity in Indigenous communities.

1.4.2 Enhanced Project Consultation and Engagement

Expectations of engagement are also increasing from regulators and other stakeholders including the BC OGC and local governments throughout the province as both the Federal and B.C. governments undergo review of the environmental assessment process and requirements. Proposed changes include adding enhanced consultation (new early planning and engagement) with affected communities, and particularly with Indigenous groups, that may be affected by projects. In order for projects to receive government approvals, a broader range of benefits must now be considered alongside the more traditional considerations of direct economic benefits such as jobs, training and other local development.

Greater expectations for regulatory and public engagement mean that the Companies will need to increase both the scope and number of stakeholder and rights holder consultations.

Additional staff and resources are required to address overall stakeholder engagement for pre-planning consultation as well as Indigenous pre-planning engagement on FortisBC's projects. Engagement is likely to take place over an extended, multi-year period. Maintaining positive relationships and continuing to build relationships with community and Indigenous leaders involves a high degree of listening and finding innovative ways to secure support and certainty for our capital investments and future project expansions.

1.4.3 Partnering for Climate Action

To recognize the role that FortisBC's services and customer interests play in broad-based GHG reduction agendas, it remains important for the Companies to work closely with key stakeholders. Since 2016, FEI has been working closely with the CoV to identify mutual areas of interest in progressing CoV toward its Renewable City Strategy and climate action targets. In 2017, FEI and the CoV signed a memorandum of understanding so that FEI's customers, residents and businesses in Vancouver will be able to maintain access to natural gas as the CoV moves toward 100 percent renewable energy sources. The memorandum is critical for FEI's customers, as the impact of losing natural gas load throughout the CoV, or elsewhere in the province, will place upward pressure on delivery rates for all of FEI's remaining customers.

In the upcoming MRP term, the Companies plan to strengthen their stakeholder relationships and proactively educate stakeholders on FortisBC's low carbon and renewable energy solutions. At the same time, this interaction provides an opportunity to identify and promote new project opportunities, such as in the areas of energy efficiency and conservation, developing renewable gas supply or examining ways to address emissions in the transportation sector, whether through EV infrastructure or converting medium-duty and heavy-duty vehicles to Compressed Natural Gas (CNG) or RNG. This work is important as public sector organizations continue to seek ways for their organizations and communities to reduce GHG emissions and ultimately become carbon neutral.

1.4.4 Research on Enhancing Stakeholder Communication

Independent research has shown that customers and stakeholders lack an understanding of FortisBC beyond its basic utility services. This includes gaps in how FortisBC is responding to environmental, community, and customer needs and concerns, and what energy services and programs it has available. Educating British Columbians on the important role of FortisBC's infrastructure in moving B.C. toward a clean, sustainable energy future is necessary to maintain and stimulate new demand, and in turn meet our customers' energy needs.

1.5 *SYSTEM OPERATIONS, INTEGRITY AND SECURITY*

To meet FortisBC's commitment to delivering energy safely and reliably, our operations are focused on ensuring customer expectations are met and continuing to focus on the efficient and effective completion of work. The following discusses the operational context at FEI and FBC along with our focus on system integrity, and physical and cyber security.

1.5.1 FEI Operational Needs

FEI continues to invest in assets that need to be maintained[28]. Most of these additions include pipe, mechanical devices and complex system components that require maintenance to keep them operating safely and reliably. In addition, FEI's assets are aging and require additional maintenance and corrective work. Customer and public emergency calls, BC One Call tickets and third-party activities around our assets and transmission line right of way (ROW) that require permits are all increasing.

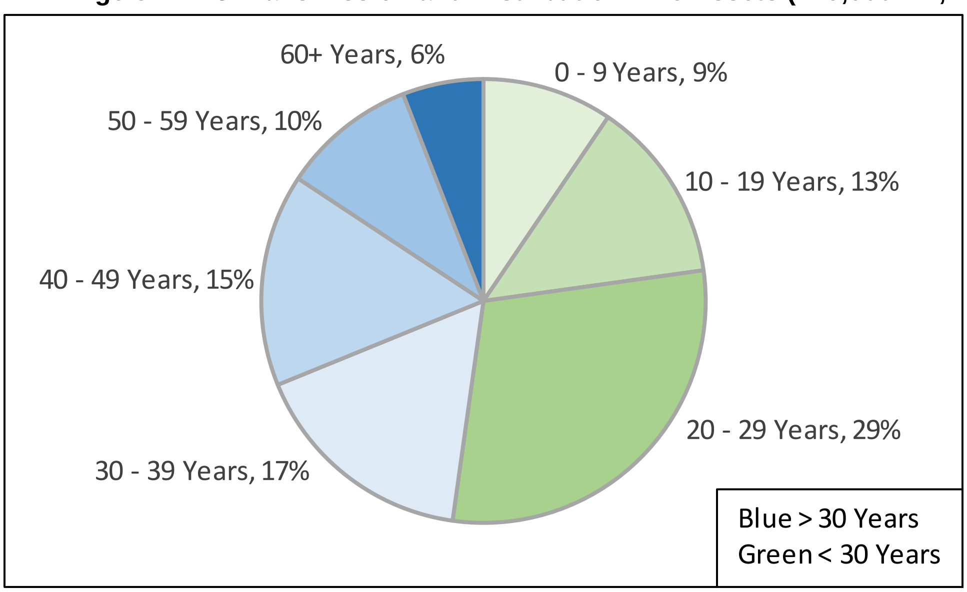
1.5.1.1 Continued System Growth

FEI continues to experience consistent high levels of new customer attachments including record growth in the conversion market. In recent years, FEI has been adding new pipe and related assets associated with attaching approximately 15,000 to 22,000 new customers per year. To support this growth, FEI must also install new assets such as stations, monitoring and controls, NGT stations, RNG facilities and LNG facilities.

1.5.1.2 Increasing Requirements for Maintenance and Sustainment of Assets

FEI is adding new assets each year and, as technology advances, requirements are changing. New equipment and systems are more complex and generally need more site or asset-specific maintenance planning and execution as compared to older equipment. Meanwhile, existing infrastructure is aging and requires more frequent maintenance to extend its life and minimize lifecycle costs. As shown in the following graph, almost half of FEI's transmission and distribution line assets are over 30 years old - a significant increase over the past decade.[29]

Figure B1-4: Age of FEI's Transmission and Distribution Line Assets (~49,000 km, % basis)



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[28] FEI has added more than 90,400 customers during the Current PBR Plan period between 2014 and 2018.

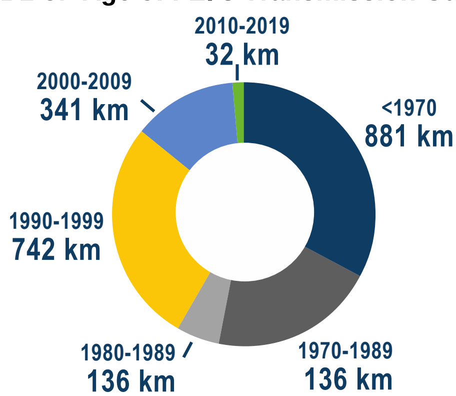
[29] 48 percent or 23.1km of T&D lines were older than 30 years in 2018 compared to 34 percent or 15.3km in 2009.

1.5.1.3 Increasing Investments Needed for System Integrity

FEI's Integrity Management Program (IMP) provides a systematic approach to ensuring asset integrity throughout the asset lifecycle for safe, environmentally responsible and reliable operations. The IMP, which is a requirement of the *BC Oil and Gas Activities Act*, is founded on FEI's objective to achieve zero incidents of significant consequences[30] associated with the operations of its gas system assets.

FEI currently operates approximately 3,000 kilometres of transmission pressure (TP) gas lines and 46,000 kilometres of distribution pressure (DP) and intermediate pressure (IP) gas lines that supply gas to customers. As shown in Figure B1-4 above, nearly half of FEI's overall pipeline assets are more than 30 years old. The age of the transmission system shows a similar pattern as demonstrated in Figure B1-5 where over half of FEI's TP gas lines are more than 30 years old and over one third were installed prior to 1970. Thus, consistent with industry practice and regulator expectations, integrity management continues to be a focus for FEI.

Figure B1-5: Age of FEI's Transmission Gas Lines



As a result of TP gas line asset vintage[31], asset location[32], and evolving integrity practices, FEI is expecting to increase expenditures in the coming years to reduce both the probability and consequences of pipeline incidents.

The following describes three initiatives that FEI will undertake during the Proposed MRP period in order to continue to proactively manage integrity.

- **Canadian Energy Pipelines Association (CEPA) Integrity First Partner** – Starting in 2019, FEI has joined CEPA as a CEPA Integrity First® Partner[33]. The Integrity First program membership includes all major Canadian pipeline operators who work collectively to support CEPA's vision of "A Safe, Socially and Environmentally

[30] FEI considers incidents of significant consequences to include: safety (serious injury or worse to any person – employees, contractors, customers or the public); environmental (irreversible, long-term harm to the environment); and service disruption (outages that affect large numbers of customers).

[31] In this context "vintage" refers to the combination of the type of materials used, and manufacture and installation practices at the time of construction.

[32] A significant portion of FEI's transmission pressure system is located in densely populated urban areas.

[33] https://cepa.com/en/ifpartner/.

Sustainable Energy Pipeline Industry for Canadians." Participation as an Integrity First Partner obligates FEI to the fundamental elements of Integrity First, including a commitment to continual improvement, development of rigorous standards, and on-going independent verification. This commitment will be evaluated on an ongoing basis through external audits to assess FEI's performance in a number of key areas including pipeline integrity, damage prevention, emergency management, control room management and water protection. Compliance is ranked on a four-tier scale ranging from "Foundational" (level 4, the lowest) to "Leading" (level 1, the highest). Ongoing participation in the program requires consistent performance at level 3 ("Continually Improving"). During 2019, FEI will be working with CEPA to establish a baseline performance level and an action plan for any areas identified as requiring improvements. Overall, this initiative will assist FEI in leveraging industry knowledge and adopting continually-improving practices in integrity management.

- **Increasing Asset Condition Monitoring** – As noted above, the majority of FEI's TP lines are more than 30 years old. Although asset age is not a primary determinant of whether an underground gas line is reaching its end-of-life, there are a number of identified failure mechanisms that are time dependent. Some of these threats, such as corrosion or cracking, can be detected through in-line inspection activities. Verification of these conditions must be conducted visually. This is done through integrity digs, where a gas line exhibiting areas of concern is excavated and exposed to confirm the presence and/or growth rate of any imperfection(s). As the average age of FEI's system continues to increase, the number of integrity digs is expected to increase over the Proposed MRP term.

- **Major Projects:** The increased need to monitor time-dependent threats has resulted in two projects each of which require applications for a Certificate of Public Convenience and Necessity (CPCN). The Inland Gas Upgrades (IGU) Project CPCN Application was filed in December 2018 and is intended to mitigate the potential for failure by rupture in a number of small diameter TP laterals in the FEI Interior region. The second project will address the risk of stress corrosion cracking in FEI's Coastal, Vancouver Island, and Interior regions. Stress corrosion cracking has been responsible for failures on Canadian pipeline systems constructed before 2000, and is recognized by pipeline operators, pipeline regulators, and pipeline technical associations as a time-dependent integrity risk that must be managed. Electro-magnetic Acoustic Transducer (EMAT)[34] inline inspection tools have been evolving especially over the past decade and are now increasingly being adopted by Canadian gas transmission pipeline operators as the standard method for managing stress corrosion cracking.

[34] EMAT is a non-destructive testing technology that has applications in a wide range of industrial sectors. EMAT is generally used to asses the condition of manufactured objects and the technology is particularly effective for detection of stress corrosion cracking and disbanded coatings.

1.5.2 FBC Operational Needs

FBC's load and asset base are growing and assets need to be maintained to evolving industry standards. FBC's focus and priority is to plan, design, build, operate and maintain assets in a sustainable manner and deliver safe, reliable service for customers.

1.5.2.1 Continued System Growth

FBC continues to grow through the addition of approximately 1,500 new customer attachments per year and the associated addition of advanced control devices and related assets. All of these devices and systems require staff to operate and maintain them, maintain related data, and respond to customers. Along with technological advancements, FBC is seeing significant load growth from EVs, server farms, as well as greenhouse operations associated with the emerging cannabis industry.

1.5.2.2 Increasing Requirements for Generation Maintenance

Existing generation infrastructure is aging[35] and requires more frequent maintenance to extend its life and continue to meet or exceed BC Dam Safety Regulations. This includes updating the Public Safety Management Plan to comply with current Canadian Dam Association guidelines. These and other initiatives are necessary to enable FBC to continue to deliver safe and reliable service to our customers.

1.5.2.3 Maintaining System Reliability

Significant capital investments in generation, transmission and distribution infrastructure have been completed over the past two decades leading to improvements in system reliability. The focus now is on maintaining existing levels of system reliability through investment in sustainment capital.

As an example, and in order to address specific concerns in the Grand Forks area, FBC filed an application for a CPCN regarding the installation of a second transmission transformer at the Grand Forks Terminal Station. Associated with this project is the decommissioning of approximately 45 kilometers of aging transmission line.

1.5.3 Enhancing Physical and Cyber Security

Protecting our assets and providing reliable energy services to our customers is a top priority for FortisBC. In an environment with increasing requirements for mobile computing, improved access to data and increased activism, it is important for our systems to continue to evolve in order to be able to respond to new and emerging threats. As such, FortisBC's programs, such as our cyber security risk and security management programs, are based on a continuous improvement model with ongoing monitoring of and adaptation to the evolving threat landscape.

35 As an example, the Upper Bonnington Generation Plant was recently inducted into the Hydro Hall of Fame for having achieved over 100 years of service.

FortisBC will enhance its focus on the security of customer information in support of providing access to secure customer tools and resources. A focus will be on tracking customer notifications and complaints of telephone-based fraud. With this activity on the rise more broadly, FortisBC will support its customers by develop strategies, such as specific customer communication, to help customers avoid falling victim to this type of fraud.

Finally, FortisBC will strengthen the physical protection of its facilities. The focus will be on enhancing FortisBC's ability to implement and maintain technologies that reduce the threat landscape, increase the ability to respond to physical and cyber security events, keep the Companies systems secure, and reduce risk to our assets.

1.6 *THE NEED FOR INNOVATION AND THE ADOPTION OF TECHNOLOGY*

For FortisBC, innovation means showing our employees, customers and stakeholders that we will look for business improvements and opportunities, whether they are driven by technology, process, product or some combination of all three. The following section discusses the importance of innovation and how FortisBC integrates innovation into its business.

1.6.1 Technology and Innovation in our Long Term Resource Plan

With evolving climate policy directed at lowering emissions and customers looking to FortisBC for solutions, innovation and the adoption of technologies over the long term is a key aspect of transitioning to a lower carbon environment.

This is particularly important for FEI as technology innovation provides a range of potential solutions on both the supply and demand side of energy service delivery. As noted in Appendix E of the FEI 2017 LTGRP, supply side innovations include technologies that may unlock larger feedstock volumes for RNG (e.g., cellulosic biogas) or enable the injection of hydrogen or synthetic methane into the natural gas stream. Demand side innovations include natural gas end uses for the transport sector, higher efficiency building envelopes and appliances (e.g., natural gas-driven heat pumps), improved methods for controlling energy use (e.g., smart thermostats), carbon sequestration, and appliances that are suitable for meeting very small heating loads.[36]

Pursuing such innovations can mitigate policy-driven risks of reduced natural gas demand, while also leading to some increases in the cost of service. Pursuing innovation provides an opportunity to proactively manage rate impacts while supporting GHG emissions reduction goals and helping customers. This also helps avoid rate impacts resulting from customers responding to GHG emission reduction goals by switching away from FEI's infrastructure. This will help to preserve BC's clean electricity for other potential end uses, such as power-to-gas, electrifying upstream industry or export to other jurisdictions within the electricity trading region.

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[36] FEI 2017 LTGRP, Appendix E; FEI 2017 Long Term Gas Resource Plan, Section 2.4.3; FEI 2017 LTGRP, Section 4.2.3.4.

While the pressures resulting from climate policy are different for FBC, stakeholder and customer expectations for leadership in innovation and energy solutions remain the same. Customers expect FBC to provide greater assistance in managing energy costs while also finding solutions to reduce GHG emissions.[37]

1.6.2 Increasing our Innovation Focus

Improvement through innovation is at the forefront in how FortisBC interacts with its customers. To that end, FortisBC intends to leverage its data assets by implementing analytics tools. This will provide deeper insights into our operations and the service we provide to customers.

FortisBC must also expand its innovation efforts across the value chain to continue to identify and develop new technologies that help customers meet their energy needs and to secure and enhance the value of our infrastructure in a lower carbon economy. Accordingly, the Companies have proposed enhanced funding for supporting innovation and the adoption of new technologies through the Innovation Fund. The Innovation Fund recognizes and fills an important gap in advancing clean growth innovation to meet BC's climate objectives.

1.7 *CONCLUSION*

There are many factors that are driving change in our operating environment. FortisBC has described the primary changes and their implications in this section of the Application. More than ever, FortisBC needs the flexibility to respond to these changes.

[37] FBC 2016 LTERP, Section 10, p. 136.

2. RATE SETTING BACKGROUND

2.1 INTRODUCTION AND SUMMARY

This section provides a description and evaluation of FortisBC's most recent multi-year rate plans, the results of the benchmarking study directed by the BCUC, summarizes FortisBC's intervener engagement process, and reviews multi-year rate plans in other jurisdictions.

Section B2.2 describes the Companies' Current PBR Plans. The Current PBR Plans are a custom-made hybrid incentive framework where the O&M expenses and certain capital expenditures are escalated with separate formulas. In addition, subject to certain conditions, some capital costs for larger, and less predictable projects can be treated outside the indexing formulas and included in rates similar to the cost of service ratemaking process. Both Proposed MRPs also include a number of safeguard mechanisms to protect the Utilities and ratepayers from unintended and/or unexpected consequences of the plans.

Section B2.3 provides an evaluation of the Companies' performance under the Current PBR Plans. The Companies' evaluation indicates that despite some challenges related to capital formulas, both FEI's and FBC's plans have resulted in considerable O&M expenditure savings as well as average rate increases at or below the level of inflation for the duration of the plans. Further, the safeguard mechanisms performed as designed and mitigated the consequences of required capital expenditures exceeding the allowed formula amounts. Nevertheless, the insufficient funding from capital-related formulas warrants some changes to the Current PBR Plans' design for future years. Further, the new MRP design can, and in FortisBC's view should, include a series of targeted incentives to encourage innovative solutions and to encourage the achievement of outcomes in emerging and strategic areas that are in the public interest.

Section B2.4 discusses the results of the benchmarking study of the Companies conducted by Concentric Advisors, ULC (Concentric). Based on the metrics reported on in the study that cover both costs and service levels, FEI and FBC are operating efficiently relative to their peers, and in comparison to the efficiency that existed in 2013.

Section B2.5 provides a summary of FortisBC's intervener discussion and feedback process. These include a number of face to face meetings with individual interveners and BCUC staff held between April 2017 and October 2018, one workshop regarding Concentric's benchmarking results and one workshop on the evaluation of the merits of MRPs and traditional cost of service rate setting mechanisms, held in November and December of 2018 respectively.

Lastly, Section B2.6 includes a discussion of the regulatory support for and increasing prevalence of multi-year incentive plans in North America as well as a summary comparison of MRP features and related regulators' decisions in various North American jurisdictions. The MRPs in these jurisdictions range from forecast multi-year rate plans with outcome-based targeted incentives to fully indexed-based MRPs in the form of revenue or price cap indexes. This review indicates that other jurisdictions are grappling with many of the same challenges to encourage efficiency and innovation. Nevertheless, the framework adopted for each utility is in line with their specific circumstances and their history with performance based rate-setting.

2.2 *FEATURES OF THE CURRENT PBR PLANS*

Both FEI and FBC have had a long history with indexed-based multi-year rate plans, going back to the 1990s. These include FEI's 1998 and 2004 MRPs as well as FBC's 1996 and 2007 MRPs. A summary discussion of these MPRs can be found in Appendix C1 to this Application. Following periods of traditional cost of service rate-setting, which included the FEI 2010-2011 and the FEI and FBC 2012-2013 Revenue Requirement Application (RRA) proceedings, the Companies returned to performance-based rate setting for the 2014-2019 period. The Companies' Current PBR Plans were the result of a lengthy regulatory process which started in June 2013 and included multiple rounds of information requests and seven days of oral hearing. Orders G-138-14 and G-139-14 issued on September 15, 2014 approved the Current PBR Plans with a number of changes and modifications from what was proposed.

A summary of the main features of the Current PBR Plans is provided in Table B2-1 below. This is followed by a more thorough discussion of plan elements and results in subsequent sections.

Table B2-1: Main Features of the Current PBR Plans

<table>
<tr><th colspan="2">Item</th><th>FEI PBR Plan</th><th>FBC PBR Plan</th></tr>
<tr><td colspan="2">Process</td><td colspan="2">Oral hearing</td></tr>
<tr><td colspan="2">Term</td><td colspan="2">Six years (2014-2019)</td></tr>
<tr><td rowspan="3">Formula</td><td>O&M</td><td colspan="2">$OM_t = OM_{t-1} * [1 + (I-X)] * (1+G/2)$
G = Percentage growth in average number of customers</td></tr>
<tr><td rowspan="2">Capital</td><td>Allowed $Cost_t = Cost_{t-1} * (1+I-X) * (1+G/2)$
Three categories: (i) growth capital, (ii) sustainment capital (iii) other capital</td><td>Allowed $Cost_t = Cost_{t-1} * (1+I-X) * (1+G/2)$
Three categories: (i) growth capital, (ii) sustainment capital (iii) other capital</td></tr>
<tr><td>G = Service line additions for growth capital, average number of customers for Sustainment and Other capital</td><td>G = Average number of customers</td></tr>
<tr><td colspan="2">I-Factor</td><td colspan="2">Composite index: 55% AWE:BC + 45% CPI:BC</td></tr>
<tr><td colspan="2">X-Factor</td><td>Fixed at 1.10% for the entire PBR term</td><td>Fixed at 1.03% for the entire PBR term</td></tr>
<tr><td colspan="2">Y-Factor</td><td colspan="2">Yes, Flow-through deferral account as well as a number of other deferral accounts such as DSM expenses, cost of gas/power supply, pension/OPEB expense.</td></tr>
<tr><td colspan="2" rowspan="2">Z-Factor</td><td colspan="2">Available for prudently incurred costs caused by exogenous factors.</td></tr>
<tr><td>Materiality threshold: 0.5% of 2013 base O&M which equalled $1.15 million.</td><td>Materiality threshold: 0.5% of 2013 base O&M which equalled $0.301 million.</td></tr>
<tr><td colspan="2">ESM</td><td colspan="2">50/50 symmetric sharing for variances in formula O&M and for earnings on formula capex variances within a dead band.</td></tr>
</table>

Item	FEI PBR Plan	FBC PBR Plan
Safeguard Mechanisms	Dead band for capital formula - If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount - One year 10% dead band or two-year cumulative 15% dead band PBR Off-ramp Off ramp triggered if earnings in any one year varies from approved ROE by more than +/- 200 bps (post sharing) and/or earnings vary from approved ROE by more than +/- 150 bps (post sharing) in two consecutive years.	
ECM	Only on a case-by-case basis	
Incremental Capital	Available through CPCN process	Available through CPCN process plus specific major non-recurring projects
	Materiality threshold of $15 million	Materiality threshold of $20 million
SQIs	Yes, Included nine SQIs and four informational indicators	Yes, Included eight SQIs and three informational indicators

2.2.1 Term

The Companies proposed a five-year PBR term starting in 2014. The BCUC Panel considered that "the time frame for the PBR plan is appropriately determined by assessing the time period over which the Companies are incented to maximize input efficiencies while the ratepayer and the utility are protected from unwarranted gains or losses"[38] and agreed that a five-year PBR term was appropriate. However, given that the decisions were issued in September 2014, the BCUC extended the terms through the end of 2019 in order to realize the full benefits of a five-year term.

2.2.2 O&M Expenses and Formula

The BCUC Panel approved a Base O&M Expense based on 2013 Approved O&M, subject to certain adjustments that resulted in minor overall changes to the proposed base values. An O&M formula escalated the base O&M amount for inflation and the annual growth in average number of customers, less productivity. Other than the quantum of the productivity factor, there were two differences from what was applied for:

i. A 0.5 multiplier was applied to the growth factor which reduced the allowed O&M amount.
ii. The inflation and growth factors were set using the actual historical numbers on a lagged basis, rather than using forecasts.

38 G-138-14, page 27 and G-139-14, page 27.

2.2.3 Capital Expenditures and Formulas

FEI and FBC classify capital expenditures as growth capital, sustainment capital, and other capital. The 2014 PBR Decisions approved the proposed capital formulas subject to the same two adjustments as were made to O&M. The capital expenditure formulas used were the same as the O&M formula, with the exception of the formula for FEI's growth capital, which substituted service line additions for customer growth.

The 2014 PBR Decision approved FEI's base capital as determined by its 2013 approved capital expenditures, subject to some adjustments. Pursuant to the amalgamation reconsideration decision,[39] the BCUC directed FEI to file a proposal for the addition of the O&M and capital requirements of FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) to FEI's base O&M and capital to reflect the amalgamated FEI entity. FEI filed its proposal to include FEVI and FEW within the PBR plan on November 14, 2014. Order G-106-15 set FEVI's sustainment capital based on a five-year average of FEVI's actual sustainment capital expenditures without any adjustment for inflation or other factors and reduced FEVI's previously approved 2014 sustainment capital by $6.3 million, which resulted in a similar reduction to Base Capital Expenditures for 2015 and each of the remaining years in the PBR term.

The BCUC also determined that FBC's base capital would be determined from its 2013 approved capital expenditures, subject to certain adjustments including the exclusion of major non-recurring projects.

2.2.4 I-Factor

In alignment with the trend in other jurisdictions to transition to composite inflation factors, the BCUC Panel supported the use of CPI:BC and AWE:BC as proposed by the Utilities and approved the composite factor as proposed, although it set the time series to the most recent July to June period.

2.2.5 X-Factor

The X-Factor values were determined through an examination of complex productivity studies filed by Utilities' and interveners' experts. After reviewing the experts' evidence, the BCUC set fixed X-Factor values, inclusive of stretch factors, of 1.10 percent for FEI and 1.03 percent for FBC.

2.2.6 Y-Factor

The BCUC in its 2014 PBR Decisions acknowledged that certain costs, whether controllable, partially controllable or non-controllable, may not be suitable for an I-X formula and, therefore,

[39] Order G-21-14.

approved the flow-through of various costs such as depreciation expense, insurance premiums, income and property taxes, interest expense, and certain non-formula O&M expenses.[40]

Pursuant to Orders G-162-14 and G-163-14, a Flow-through deferral account captured variances from forecast for the majority of items subject to this treatment. Certain other items such as pension expense continued to have separate deferral accounts, and FEI's commodity and midstream costs[41] and both Utilities' DSM costs continue to have separate regulatory processes.

2.2.7 Z-Factor

Similar to FortisBC's previous MRPs, the Current PBR Plans include a Z-Factor mechanism for treatment of exogenous cost items. However, in contrast to the previous MRPs, the BCUC Panel set a materiality threshold as one of its five eligibility criteria, as listed here:

- attributable to events entirely outside the control of a prudently operated utility;
- directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
- impact of event is unforeseen;
- prudently incurred costs; and
- costs/savings must exceed the materiality threshold of 0.5 percent of base O&M amount.

2.2.8 Earning Sharing Mechanism

The BCUC Panel determined that the inclusion of a symmetric ESM would be beneficial to both the Utilities and customers, balancing the interests of the customer and the utility. The approved ESM is an equal sharing of gains and losses related to formulaic (controllable) O&M and the return on capital expenditures.

2.2.9 Capital Dead-band

In their 2014 PBR Applications, FEI and FBC proposed to include a "capital dead-band" of ten percent of approved formulaic expenditures, to safeguard ratepayers and the Companies from significant variances between actual and formula driven capital expenditures. Under this approach, variances from approved expenditure amounts and within the dead band, were excluded from rate base during the PBR term. As approved by Orders G-196-17 and G-38-18, when the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year is adjusted by the amount that actual capital fell outside of the dead band, and the capital expenditures utilized in calculating the earnings sharing are adjusted by the same amount.

[40] Refer to Section C4 for a complete list of items subject to flow-through treatment.
[41] FBC's revenue and power purchase expense variances were included in the Flow-through deferral account for the duration of the PBR Plan.

In addition to the proposal for a one year 10 percent dead band and in response to interveners' request, the BCUC approved a two year cumulative 15 percent dead band for formulaic capital spending.

2.2.10 Financial Off-ramp Provisions

In addition to the ESM and capital dead band, the Current PBR Plans include a third safeguard mechanism in the form of financial off-ramps. The BCUC directed that an off-ramp be triggered if earnings in any one year varies from the approved ROE by more than +/- 200 basis points (post sharing). The BCUC Panel further directed that the off-ramp would be triggered if earnings averaged more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years.

2.2.11 Capital Exclusion Mechanism

The 2014 PBR Decisions confirmed that certain capital projects should be treated outside the PBR formula. The BCUC also invited stakeholders to submit further evidence regarding the eligibility criteria and regulatory process for these projects in a separate proceeding. Order G-120-15 issued on July 22, 2015 aligned the PBR materiality threshold and CPCN thresholds, which were set at $15 million for FEI and $20 million for FBC, and directed that the Utilities demonstrate that a project that falls above the PBR materiality threshold does not result from combining smaller projects. By Order G-80-16, the BCUC confirmed that certain large projects that had been excluded from base capital in FBC's 2014-2018 PBR Plan Application would continue to be excluded from base and subject to approval on a case by case basis.

2.2.12 Service Quality Indicators

FEI's Current PBR Plan includes nine service quality indicators and four informational indicators; FBC's Current PBR Plan includes eight service quality indicators and three informational indicators. Subject to the BCUC's judgement, a sustained serious degradation of the service quality could warrant a change in earning sharing ratio from the existing 50:50 sharing ratio to 60 percent ratepayers and 40 percent utility.

2.3 *EVALUATION OF THE CURRENT PBR PLANS*

The Current PBR Plans are in effect until the end of 2019. As such, an evaluation of the full term of the Current PBR Plans is not currently possible. Nevertheless, the information available in the last five Annual Reviews (Annual Reviews for 2015 to 2019 rates) can be used to evaluate the Companies' performance during this period.

The evaluation of a PBR plan can be conducted in different fashions. One measure of a PBR plan's success relates to the amount of savings achieved and its impact on rates. This would include the identification of cost savings embedded in the formulas' productivity value, the evaluation of variances between the actual costs and formula generated amounts in each year of the plan, the trend in costs and rates during the PBR term as well as the unaccounted for savings not explicitly measurable due to their nature. The latter category may refer to the savings related to increased regulatory efficiencies manifested in reduced regulatory costs. The increased regulatory efficiency can also free up time of utility employees to focus on load building opportunities, plan and/or implement new climate related initiatives[42] and deal with other business challenges that otherwise are challenging to undertake without additional resources. Another approach to the evaluation of PBR plans relates to the study of the interaction among individual plan's features (for instance, how a plan's safeguard mechanisms can protect ratepayers and the utility from unintended consequences of the approved PBR plans). Our review indicates that the overall package of the Current PBR Plans' features has resulted in sizable benefits to both ratepayers and the Utilities.

From the outset of the Current PBR Plans, ratepayers benefited from the immediate expected productivity amounts embedded in the formulas' X-Factor value. In addition, O&M expense has been consistently below the formula levels, bringing significant savings to ratepayers through the earnings sharing mechanism. Further, the Plans' safeguard mechanisms, notably the earnings sharing and capital dead-band mechanisms, have performed as designed and mitigated the risks to the Utilities and ratepayers appropriately, despite challenges in keeping capital expenditures within formula amounts. Lastly, the success of the Current PBR Plans are highlighted by the level of rate increases over the term of the plans. FEI has been able to keep its average delivery rate increases below the average rate of inflation during the PBR term while growing its business at a higher pace than what was assumed in its 2013 going-in rates. FBC's rate increases have been close to inflation on an annual average basis.

In the following sections, FortisBC's performance with respect to O&M expenditures, capital expenditures, regulatory efficiency and rates are discussed in more detail[43].

2.3.1 O&M Expenditures

2.3.1.1 FEI's O&M Expenditures

FEI's O&M expenditures have trended favourably since the outset of PBR term. To the end of 2019, FEI is projecting to realize:

- $54.4 million in savings[44] by meeting the productivity factor embedded in the formula (a fixed X-Factor value of 1.1 percent). Because the productivity improvement factor is part of the formula, these savings are all to the benefit of ratepayers; and
- $44.7 million in savings by spending less than the allowed formula amount. These savings are shared equally between customers and the utility.

Table B2-2 below shows the O&M savings for each year of the Current PBR Plan.

[42] Initiatives such as EV charging, RNG and NGT are some examples.
[43] The performance of service quality indicators is another important part of any PBR evaluation. The Companies' SQI performance evaluation can be found in Appendices C5-1 and C5-2 of the Application.
[44] Sum of column e in Table B2-2.

Table B2-2: FEI Formula O&M Savings from 2014 to 2019 ($ millions)

Year	Actual (a)	Formula With 1.1% PIF (b)	Savings above the Formula (c= b-a)	Formula without 1.1% PIF (d)	Savings related to 1.10% PIF (e= d-b)	Total Savings to customer (f= 0.5*c + e)
2014[45]	191.0	198.5	7.5	200.7	2.2	5.9
2015	225.4	235.6	10.2	240.4	4.8	9.9
2016	225.9	238.1	12.2	245.6	7.5	13.6
2017	232.5	240.4	7.9	250.7	10.3	14.3
2018	238.7	243.6	4.9	256.8	13.2	15.7
2019P	246.9	248.9	2.0	265.3	16.4	17.4
Total						**$76.8**

As can be seen, FEI has been able to achieve considerable O&M savings in each year of the Current PBR Plan. The pattern of O&M savings above that embedded in the formula (column c) indicates an increase in savings for the first three years of the Current PBR Plan with a peak in 2016. As the Current PBR Plan approaches its final year, the effect on O&M of the accumulating productivity factor (column e) offsets the earlier savings achieved, and cost pressures not considered in the base 2013 O&M increase, resulting in a slowdown in these incremental O&M savings, but maintaining the overall level of savings realized by customers (column f).

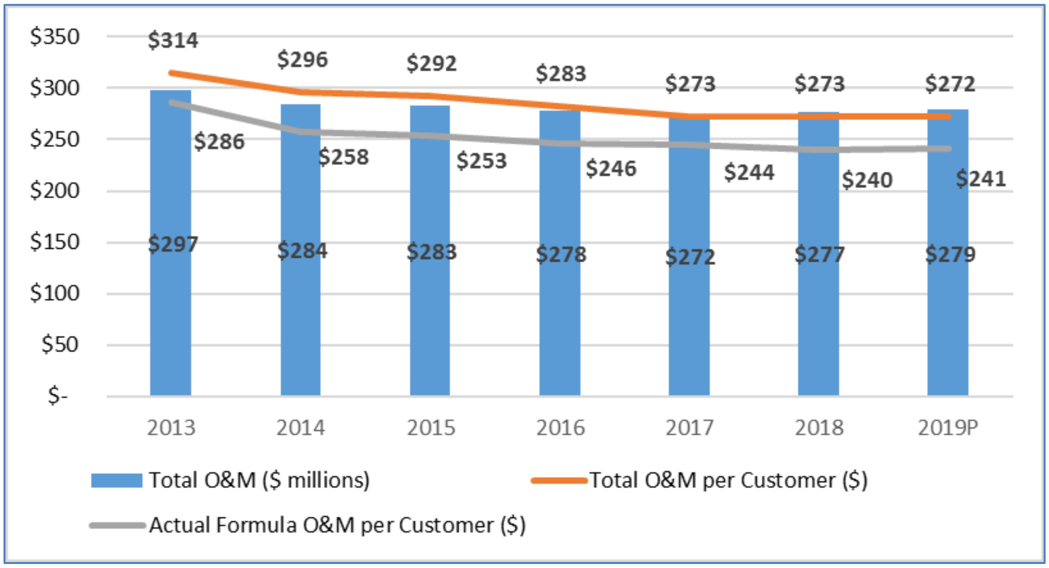
The trend in O&M savings can be further analyzed using a unit cost approach. As indicated in Figure B2-1 below, the actual Formula O&M per customer metric (adjusted for inflation) has decreased by approximately 16 percent from $286 per customer in 2013 prior to the start of the PBR to $241 per customer in 2019 (a compound annual growth rate of approximately negative 2.8 percent[46]). Further, the actual Total O&M per customer metric has decreased by more than thirteen percent[47].

45 The large increase from 2014 to 2015 actual and formula amounts is due to the amalgamation with Vancouver Island (VI) and Whistler utilities.

46 Compound Annual Growth Rate (CAGR) is calculated as [(241/286)^(1/6)]-1

47 The actual formula O&M refers to the O&M spending envelope that is subject to the indexing formula while the actual Total O&M is the sum of the actual O&M subject to formula and other flow-through O&M items not subject to formula.

Figure B2-1: FEI Actual O&M in Real Dollars from 2013[48] to 2019



2.3.1.2 FBC's O&M Expenditures

FBC's O&M expenditures have also trended favourably. By the end of 2019, FBC is projecting to achieve:

- $12.0 million in savings[49] by meeting the productivity factor embedded in the formula (a fixed X-Factor value of 1.03 percent). Because the productivity improvement factor is part of the formula, these savings are all to the benefit of ratepayers; and
- $6.5 million in savings achieved by spending less than the allowed formula amount. These savings are shared equally between customers and the utility.

Table B2-3 below shows the O&M savings for each year of the Current PBR Plan.

Table B2-3: FBC Formula O&M Savings from 2014 to 2019 ($ millions)

Year	Actual (a)	Formula with 1.03% PIF (b)	Savings above the Formula (c = b – a)	Formula without 1.03% PIF (d)	Savings related to 1.03% PIF (e = d – b)	Total Savings to customer (f = 0.5*c + e)
2014	52.0	52.7	0.7	53.3	0.5	0.9
2015	51.9	53.0	1.1	54.1	1.1	1.6
2016	51.8	53.6	1.8	55.3	1.7	2.5
2017	52.5	54.1	1.6	56.3	2.3	3.0

48 2013 numbers include the Customer Service deferral related expenditures of approximately $14.5 million. If this item is removed from calculations, the total O&M, total O&M per customer and actual formula O&M per customer in 2013 would decrease to $281, $297 and $269 million dollars (adjusted to 2019 dollar) respectively.

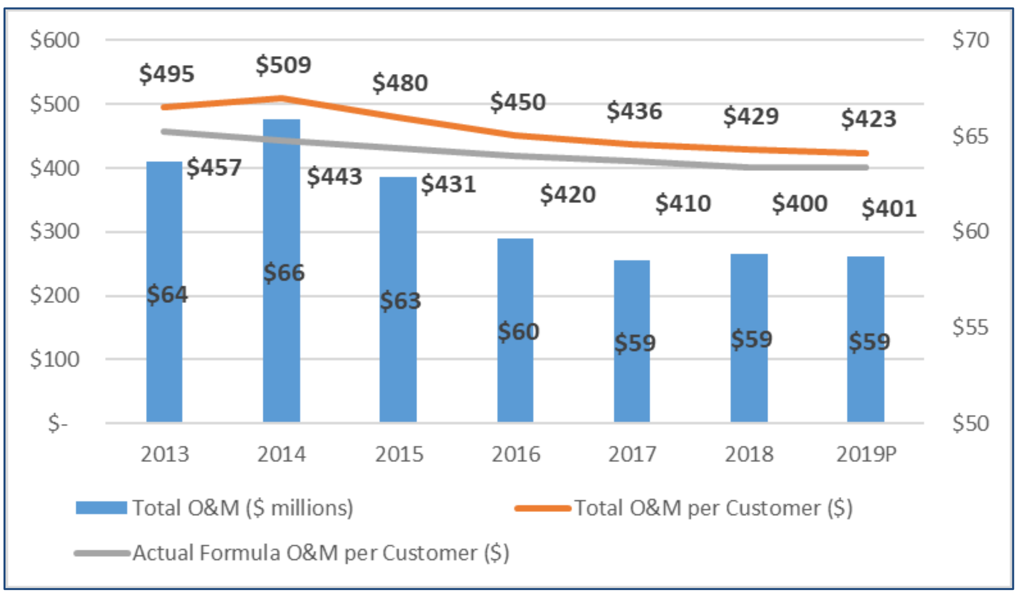
49 Sum of column e in Table B2-3.

Year	Actual (a)	Formula with 1.03% PIF (b)	Savings above the Formula (c = b – a)	Formula without 1.03% PIF (d)	Savings related to 1.03% PIF (e = d – b)	Total Savings to customer (f = 0.5*c + e)
2018	53.9	54.8	0.9	57.6	2.9	3.3
2019P	55.6	56.1	0.5	59.6	3.5	3.8
Total						**15.2**

FBC's O&M savings exhibit a profile similar to FEI's, with the greatest savings achieved in 2016.

Using a unit cost approach, and as indicated in Figure B2-2 below, actual formula O&M per customer (adjusted for inflation) has decreased by approximately 12 percent from $457 per customer in 2013 to $401 per customer in 2019 (a compound annual growth rate of approximately negative 2.2 percent)[50]. Total O&M per customer has decreased by more than 14 percent over the period[51].

Figure B2-2: FBC O&M from 2013 to 2019



2.3.2 Capital Expenditures

Despite a strong focus on productivity throughout the Current PBR Plans' term, FortisBC faced challenges in meeting the level of capital expenditures required to meet customer growth and maintain its capital assets within the formula capital amount. Capital spending has exceeded the formula amounts in each year of the Current PBR Plans to date, and is expected to do so in

50 CAGR of -2.2% is calculated as [(401/457)^(1/6)]-1.

51 The actual formula O&M refers to the O&M spending envelope that is subject to the indexing formula while the actual Total O&M is the sum of the actual O&M subject to formula and other flow-through O&M items not subject to formula.

2019. The factors that influenced FEI's and FBC's capital spending are summarized in the following sections and discussed in more detail in Appendix B8-1 and Appendix B8-2.

2.3.2.1 FEI's Capital Expenditures

Under the Current PBR Plan, FEI's capital expenditures subject to formulas are divided into three main categories: (i) Growth capital, (ii) Sustainment capital and (iii) Other capital. FEI has faced challenges in all three categories and has spent more than the formula amounts in the majority of the PBR years.

2.3.2.1.1 FEI GROWTH CAPITAL

Table B2-4 below shows FEI's Growth capital expenditures during the 2014-2019 period. Increases in Growth capital to meet customer demand have been the main contributor to overall capital expenditure variances over the term.

Table B2-4: FEI Growth Capital Variance from 2014 to 2019 ($ millions)

Year	Actual	Formula	Variance
2014	24.231	21.478	(2.753)
2015	45.776	28.480	(17.296)
2016	47.500	33.262	(14.238)
2017	59.542	33.477	(26.066)
2018	82.884	37.485	(45.399)
2019P	63.328	40.143	(23.185)
Total	323.262	194.325	(128.937)

As can be seen, actual Growth capital has outpaced the formula-generated Growth capital in every year. Appendix B8-1 of the Application provides a detailed breakdown and explanation of Growth capital variances divided into the two major categories of service line addition-related Growth capital variances and mains-related Growth capital variances.

In summary, the annual variances can be attributed to two main factors:

- Developments during the PBR term that were not initially anticipated in going-in rates (2013 base year Growth capital expenditures) caused an increase in unit costs. These developments include changes to the mix of customer type and location of new attachments. For instance, the increase in growth in industrial mains during the PBR years compared to base year assumptions has led to increased mains additions unit costs[52]. Further, the increase in service line additions activity on Vancouver Island

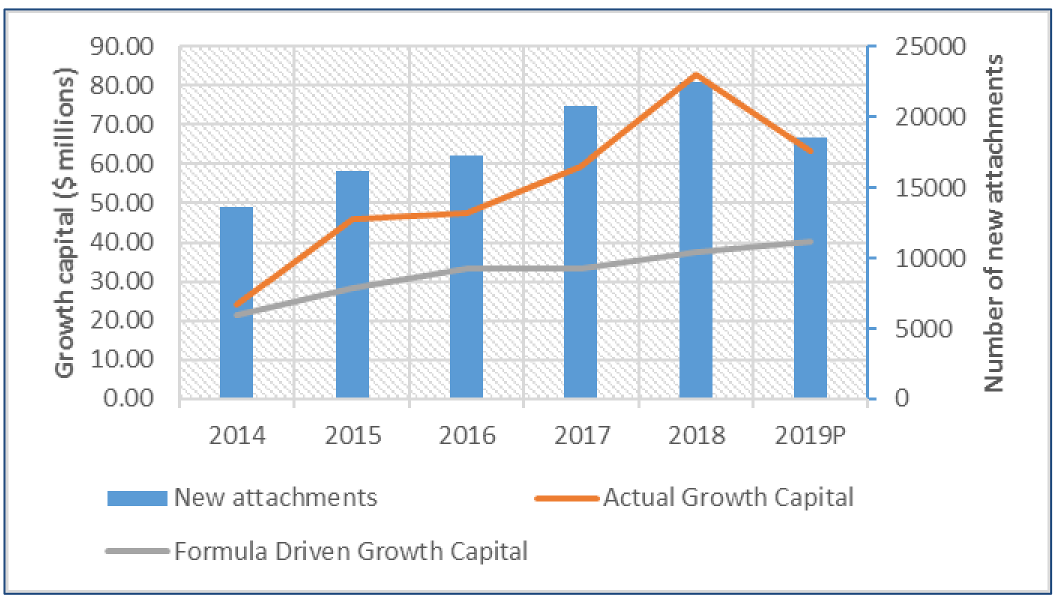
[52] In 2010, the year that was used to develop the 2013 base for the PBR formulas, there was only one new main with a cost greater than $100 thousands while during the PBR years the number of mains additions costing more than $100,000 increased significantly to 10 to 15 projects per year.

(where costs are higher) compared to the base year has also led to an increase in overall unit costs[53].

- The use of historical values for formula inputs and the 50 percent reduction in the formulas' growth factors, the impact of which is illustrated below.

Figure B2-3 below shows the trend in the number of new attachments from 2014 to 2019 compared with the formula generated and actual growth capital amounts. As shown, the formula Growth capital lags the trend in new attachments. For instance, the trend in number of new attachments indicates a jump between 2016 and 2017. The increase in actual Growth capital from 2016 to 2017 reflects this change while the formula generated amount does not. A simple correlation analysis between the number of new attachments and actual and formula Growth capital amounts indicates that the correlation coefficient between the number of new attachments and actual costs is close to 0.95, while the correlation coefficient between the number of new attachments and the formula-generated Growth capital is lower at 0.79. This reinforces FEI's position in this Application, and its proposal in the FEI 2014-2018 PBR Plan proceeding, that formula inputs, and particularly the growth factor, should be forward looking and be set based on forecast numbers, and that the 0.5 multiplier to growth factor is not required.

Figure B2-3: FEI Trend in New Attachments Compared with Actual and Formula-driven Growth Capital



53 In 2014 and after Whistler and Vancouver Island were amalgamated with FEI, FEVI SLAs represented 21 percent of the total SLAs of 10516. The share of FEW SLAs during the PBR term increased consistently however from 26 percent in 2016 to 36 percent in 2018.

2.3.2.1.2 FEI SUSTAINMENT AND OTHER CAPITAL

The variance between actual and formula-driven amounts for the Sustainment and Other capital category subject to a PBR formula is presented below.

Table B2-5: FEI Sustainment and Other Capital Variance* from 2014 to 2019 ($ millions)

Year	Sustainment and Other Capital			% variance to formula
	Actual	Formula	Variance	
2014	100.168	98.343	(1.825)	1.9%
2015	107.803	110.901	3.098	2.8%
2016	114.641	112.053	(2.588)	2.3%
2017	139.416	113.104	(26.311)	23.3%
2018	150.329	114.596	(35.733)	31.2%
2019P	144.359	117.116	(27.243)	23.3%
Total	756.655	666.113	(90.542)	13.6%

* Excluding pension and OPEB

As can be seen, with the exception of 2015, the variances for Sustainment and Other capital are negative, meaning that the actual spending was greater than the formula generated amounts. The total variance for Sustainment and Other capital spending over the entire PBR term is approximately 14 percent of the formula generated amount. Similar to Growth capital, a detailed breakdown and explanation of the reasons behind these variances is provided in Appendix B8-1 to this Application.

The biggest contributor to the variance attributed to Sustainment capital relates to the addition of FEVI and FEW to FEI's formula capital base in 2015. Order G-106-15 directed FEI to set FEVI's sustainment capital base using a five year average[54] of FEVI's actualSsustainment capital expenditures without any adjustment for inflation or other factors, and reduced FEVI's previously approved 2014 Sustainment capital by $6.3 million, which resulted in a similar reduction to Base capital expenditures for 2015 and each of the remaining years in the PBR term. FEI tried to reduce or defer its spending in the Other capital category to mitigate the effects of the BCUC's decision. However, FEI was not able to overcome this significant reduction.

As detailed in Appendix B8-1, it was a combination of the adjustment described above and other factors that resulted in capital spending higher than the formula generated amounts in the PBR term.

[54] The BCUC decision stated that the five-year average was selected based on its best judgement.

2.3.2.2 FBC's Capital Expenditures

Like FEI, FBC categorizes its capital expenditures as: (i) Growth capital, (ii) Sustainment capital, or (iii) Other capital. In the Current PBR Plan, a single formula was applied to FBC's formula capital.

Table B2-6 below shows FBC's capital spending from 2014 to 2019.

Table B2-6: FBC Capital Expenditures Variances 2014 to 2019 ($ millions)

Year	Capital Expenditures			% variance to formula
	Actual	Formula	Variance	
2014	42.665	42.193	(0.472)	1.1%
2015	44.791	42.384	(2.408)	5.7%
2016	45.838	42.874	(2.964)	6.9%
2017	59.053	43.254	(15.799)	36.5%
2018	60.187	43.818	(16.369)	37.4%
2019P	56.500	44.862	(11.638)	25.9%
Total	309.034	259.385	(49.649)	19.1%

As shown in Table B2-6, in total, capital expenditures are projected to exceed formula by approximately 19 percent over the term of the PBR. FBC has identified a number of factors contributing to the higher capital expenditures during the PBR Term that are described in more detail in Appendix B8-2.

2.3.2.3 Capital Mitigation Measures and Safeguard Mechanism

As discussed above, FortisBC faced challenges in keeping the level of capital expenditures required to meet customer growth and to maintain its capital assets within the formula capital amounts.

The Companies mitigated some of these challenges through various measures. These measures included initiating projects earlier in the planning process in order to better assess and schedule resourcing requirements for design and construction. Projects and programs were also prioritized in such a manner as to allow for early engineering and design and optimized procurement of equipment and contracting services. Further, when possible, the Companies combined projects into one construction schedule to reduce shut down and start up operational costs.

These measures helped the Companies alleviate some of the cost pressures. However, the cost pressures exceeded the Companies' ability to re-prioritize or defer further work within the formula capital spending envelope, while completing essential and mandatory work and without incurring an unacceptable level of risk to the system. The resulting increase in Sustainment activities, combined with Growth capital pressures, resulted in FEI's and FBC's capital expenditures being above the formula for the term of the Current PBR Plans.

While the spending over the formula amount reduced the amount of earnings available to be shared, the Current PBR Plans include a number of safeguard mechanisms, such as the capital dead band mechanism, that performed as designed by mitigating the impact of the capital cost pressures. This is highlighted by the following statements from the BCUC:

> FEI raises a concern as to the formula not adequately compensating FEI for its capital expenditures. The Panel notes a feature of PBR is the inclusion of a dead band which allows FEI to apply to rebase its capital expenditures covered by the PBR in the event actual costs exceed formula generated costs cumulatively over two years by greater than 15 percent or 10 percent in a single year. The Panel acknowledges this PBR feature does not mitigate the risk of FEI exceeding its formula-driven capital expenditure limit in any given year but it does limit the impact on FEI's ROE[55].

> It is clear based on the evidence that FEI expects to exceed the capital dead-band in each of the remaining years of the PBR Plan term and that growth capital in particular will continue to exceed formula amounts. The Panel also notes FEI's response to BCUC IR 6.3 in which FEI confirmed that there is little likelihood that the volume and cost assumptions utilized in developing the PBR Base Capital costs for growth capital will be reflective of actual results during the remainder of the PBR term. Given these circumstances, re-basing formula capital would generally be an appropriate action to take so as to bring the formula spending into better alignment with FEI's actual capital spending needs. Further, it is clear that the Commission in the PBR Decision contemplated re-basing as a potential course of action, as the Commission stated, when considering the cumulative impact of capital spending outside the dead-band: "The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula"[56].

Since FortisBC is proposing to move away from a formula approach for the majority of its capital expenditures in this Application, these issues are less likely to arise in the Proposed MRPs. For growth capital, FEI has directly addressed the challenges shown above with its revised unit cost base and annual re-forecast of activities as described in Section C3.3.1.

2.3.3 Regulatory Efficiency

One of the benefits of multi-year rate plans over traditional cost of service regulation relates to their higher level of regulatory efficiency. The benefits of regulatory efficiency are twofold: (i) reduced regulatory costs associated with the regulatory process and (ii) increased utility focus

[55] BCUC Order G-129-16, p.18.
[56] BCUC Order G-196-17, pp 9-10.

on managing and growing the business (such as load building opportunities) and increased operational flexibility to address the growing pace and scope of energy industry transformation.

A multi-year rate plan reduces the number of comprehensive revenue requirement reviews, replacing them with more limited annual reviews. The last two FEI PBR plans were in place for six years, and FBC had a six-year and a five-year plan. Under recent cost of service applications, revenue requirements have been set for a two-year period, which is the maximum length of test period experienced historically. This means that over a six-year period the number of comprehensive revenue requirements reviews have been reduced from three proceedings to one. Tables B2-7 and B2-8 below summarize the costs of the 2014-2018 PBR Plan proceedings and the 2015 through 2019 annual reviews, and compares them to the cost of the 2012-2013 RRA proceedings in nominal dollars for FEI and for FBC. The average annual cost for the PBR proceeding is the sum of the PBR costs plus the total Annual Review costs divided by six years. The average annual cost for the RRA is the total two-year cost divided by two.

Table B2-7: FEI PBR and Cost of Service Proceedings Cost Comparison ($000s)

Type of Cost	2014-2019 PBR	Annual Reviews 2015-2019 (Average)[57]	2012-2013 RRA
BCUC Costs	$ 295	$ 24	$ 389
Intervener PACA	477	40	351
Consulting and Legal	1,037	67	788
Other/Misc.	22	1	32
Total	**$ 1,831**	**$ 132**	**$ 1,561**
Average Annual Cost	**$ 415**		**$ 780**

Table B2-8: FBC PBR and Cost of Service Proceedings Cost Comparison ($000s)

Type of Cost	2014-2019 PBR	Annual Reviews 2015-2019 (Average)[58]	2012-2013 RRA
BCUC Costs	$ 208	$ 23	$ 273
Intervener PACA	453	40	243
Consulting and legal	859	62	676
Other/Misc.	20	0	129
Total	**$ 1,541**	**$ 125**	**$ 1,321**
Average Annual Cost	**$ 360**		**$ 661**

As can be seen in the tables for both Utilities, the 2014-2018 PBR Plan proceeding costs were higher than the 2012-2013 Cost of Service (COS) proceeding costs. However, on average, annual rate-setting costs under a multi-year rate regime are significantly lower than under Cost

[57] FEI 2016 Annual Review costs exclude the consultant related costs for the depreciation study.

[58] FBC 2016 Annual Review costs exclude the depreciation study. FBC 2012-2013 RRA proceeding included a review of the 2012 Integrated System Plan. Costs of the 2011 depreciation study and consulting fees related to the Integrated System Plan component of the proceeding are excluded.

of Service rate-setting, and the cost gap will increase with the length of the multi-year rate plan term[59].

It is important to note that the costs shown in the tables above represent external costs only. FortisBC also incurs labour and other internal expenses in the preparation and review of its applications. The intensity of effort is higher and much more impactful for the organization as a whole for Cost of Service filings compared to MRPs, especially because there are efficiencies gained in consistent Annual Review proceedings that involve only a limited number of internal staff. Because Cost of Service proceedings by their nature canvass all aspects of FortisBC's operations, virtually all of FortisBC's departments are involved in the process. Preparing revenue requirement applications, answering detailed levels of information requests, preparing for and participating in oral hearings, responding to undertakings and other regulatory processes requires the dedication of thousands of hours of employee' times. Having to commit these hours to the regulatory process, while necessary, represents a significant time commitment away from other job requirements.

The time savings that result from the reduced regulatory burden under MRPs can be used to accomplish other important tasks. FEI's 2016 rate design proceeding can be considered as a good example. The cost of service allocation model and all related bill impact models in this proceeding were produced by FEI's existing regulatory team with limited external involvement. FEI's internal regulatory managers would not have been able to conduct this time consuming and specialized task if they were at the same time involved in comprehensive revenue requirement proceedings. FEI would have needed to retain an external expert to assist with the workload, and incurred additional costs. The flexibility and regulatory efficiency of the Current PBR Plan allowed FEI to perform these tasks internally with less cost and a greater depth of understanding of the individual circumstances of the utility operations. These types of savings, while difficult to measure with full accuracy, are an example of the benefits of a multi-year rate plan.

Further, the longer-term nature of an MRP frees up utility resources to focus on revenue generating and load building opportunities, meeting customer expectations, and addressing the challenges and opportunities of government's energy policy and industry transformation (as discussed in Section B1).

These benefits are articulated both in regulators' decisions and independent regulatory studies. For instance, the Hawaii Public Utilities Commission's 2018 Order to institute a proceeding to investigate performance-based regulation states[60]:

> As demonstrated by experience in other jurisdictions, PBR can provide a variety of benefits, including; advancing regulatory goals; providing utilities with increased flexibility, opportunity, and accountability to pursue identified goals;

[59] 2014 PBR proceeding regulatory costs were higher than other PBR proceedings in the past. This can be partially attributed to the time consuming and highly specialized review of the complicated TFP studies produced by two experts and the lengthy seven day hearing process.

[60] Hawaii PUC; Docket No. 2018-0088; Order No. 35411; p.4.

> and freeing up limited regulatory resources to focus on overseeing utility success in achieving public priorities.

Similarly, the following excerpts from a recent regulatory research report sponsored by the US government indicate that the regulatory efficiency attributed to MRPs can lead to better management of utility resources:

> MRPs also can increase the efficiency of regulation. Rate cases can be less frequent and better planned and executed. MRPs also facilitate scheduling rate cases so that proceedings overlap less. Streamlining ratemaking processes can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues, such as rules of prospective application. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively. Streamlined regulation has special appeal in situations where costs of regulation are especially high due to numerous utilities, large utilities or especially difficult regulatory issues. It is not surprising, then, that several commissions with unusually large regulatory burdens (e.g., Ontario and Germany) have been MRP leaders[61] ….

> Use of MRPs for UDCs may also increase as they complete accelerated grid modernization programs that complicate plan design and return to gradual cost growth. Companies and commissions with unusually large regulatory burdens gain special advantages from streamlined regulation. Some of these companies and commissions are likely to be MRP leaders[62].

2.3.4 Rate Trend

The growth trend in rates is another indicator of performance during the PBR term and represents what customers directly see and experience. While the rates are impacted by a number of inputs, some of which are outside the PBR framework, the ongoing focus on finding and achieving efficiencies highlighted by significant reductions in O&M expenditures for both Utilities, and the increased ability to focus on customer and market growth supported by increased certainty of a longer ratemaking period, have been important factors in mitigating rate increases during the term of the Current PBR Plans.

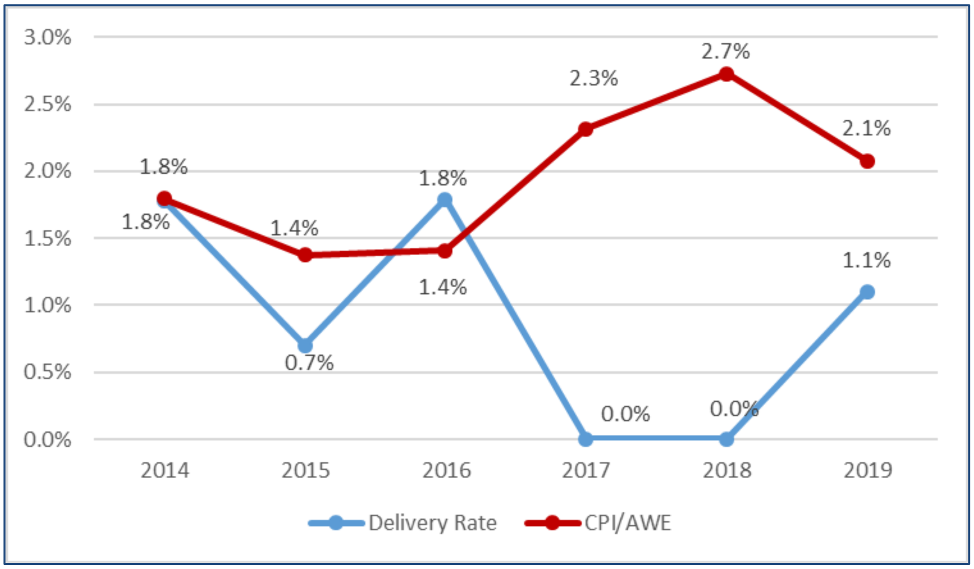
2.3.4.1 FEI Delivery Rate changes

Figure B2-4 below compares FEI's delivery rate trend with the composite inflation factor used in the PBR formulas[63]. As can be seen, FEI's delivery rate increases in the majority of the PBR

[61] Lawrence Berkeley National Laboratory (2017); "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities", page. 3.8.
[62] Ibid; page 3.12. A UDC is a Utility Distribution Company.
[63] The composite inflation factor used in Figure B2-5 and B2-5 are weighted 45 percent CPI:BC and 55 percent AWE:BC and are for the calendar years corresponding to the Utilities' fiscal years.

years have been below the rate of inflation, with no rate increase at all in the years 2017 and 2018. In percentage terms, FEI's average delivery rate growth for 2014 through 2019 is approximately 0.9 percent while the average inflation rate during the same period is approximately 2 percent.

Figure B2-4: FEI Delivery Rate Changes during the PBR Term



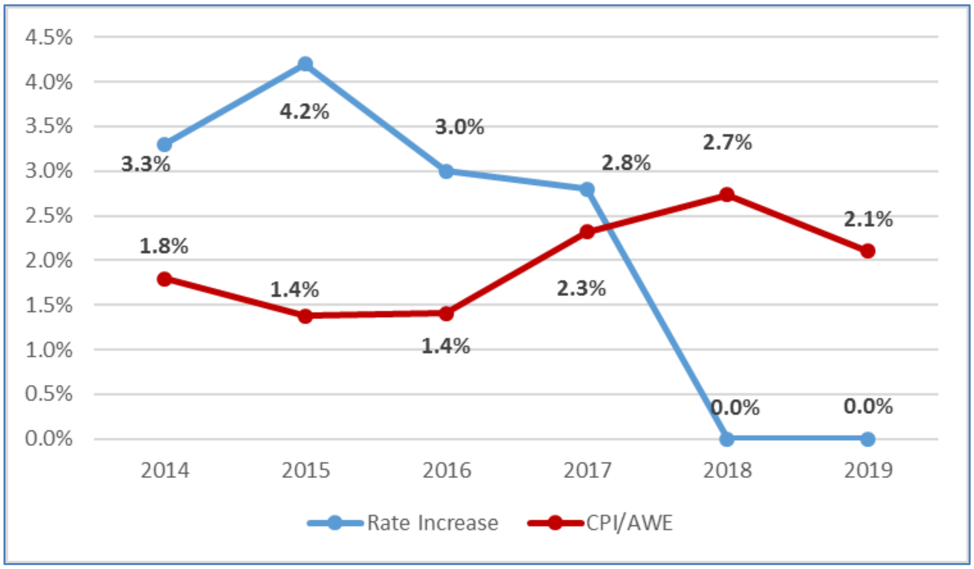
To better understand the context for these rate changes, which were impacted by the O&M savings discussed in Section B2.2.2.1.1 above, the following should be considered:

- **Customer growth increased capital needs, and revenue:** The Current PBR Plan period coincided with a high growth period for FEI. This high growth period put significant pressure on FEI's capital requirements but, on the upside, provided FEI with additional revenue, helping to mitigate the rate increases that otherwise would have occurred.
- **Major projects were added to the rate base:** FEI achieved an average growth in delivery rates that was lower than average inflation despite adding large capital projects to rate base during the term of the Current PBR Plan. These included the Coastal Transmission System project, Tilbury Expansion, and the Vancouver section of the Lower Mainland Intermediate Pressure System Upgrade project. In total, these projects added approximately $700 million to FEI's rate base, without equivalent offsetting revenues.
- **Rate Smoothing also played a role in FEI's rate profile:** The BCUC approved the deferral of FEI's revenue surpluses for both 2017 and 2018. Without this, FEI's actual rate performance over the PBR term would have been even better than portrayed in Figure B2-4. At the end of the Current PBR Plan term, a net balance in the 2017-2018 Revenue Surplus deferral account of $42 million (before tax) is still available to customers for future rate mitigation or smoothing.

2.3.4.2 FBC Rate Changes

As seen in Figure B2-5 below, FBC's rate increases have trended downwards over the term of the Current PBR Plan, overall averaging slightly higher than inflation (a compound annual growth rate of 2.2 percent compared to approximately 2.0 percent for inflation).

Figure B2-5: FBC Rate Changes during the PBR Term



In addition to the O&M savings described in Section B2.2.2.1.2 above, some of the factors that impacted FBC rates on an annual basis include the following:

- **WAX CAPA Began in 2015:** The single most significant factor impacting rates over the term of the Current PBR Plan was the 40-year capacity purchase agreement with the Waneta Expansion Limited Partnership (WAX CAPA) beginning in 2015. The BCUC, in finding the WAX CAPA to be in the public interest, recognized that the long-term nature of the agreement had the potential for disproportionate rate impacts in the early years of the agreement[64], and the WAX CAPA did impact rates materially in 2015 and 2016 as seen in Figure B2-5 above. The WAX CAPA provides for annual price escalation at moderate levels, providing stability of costs for the capacity entitlements that it provides.
- **Variances in flow-throughs**: Year-to-year variations in the Flow-through deferral account amortization also contributed to annual rate changes. The largest of the components that are afforded flow-through treatment are the revenue and power purchase expense variances which are largely load-related and determined by variances in customer growth, usage, or weather.
- **Unanticipated one-time costs:** The $8.5 million retroactive Celgar[65] Interim Period Billing Adjustment, arising from the Stage IV Decision in FBC's Application for Approval

64 Order E-15-12 dated May 30, 2012.
65 Zellstoff Celgar Limited Partnership.

of Stepped and Stand-by Rates for Transmission Customers (Order G-149-15), was recovered through rates in 2017.

- **Rate Smoothing also plays a role in FBC's rate profile:** The BCUC approved the deferral of FBC's revenue deficiency in 2018 and revenue surplus in 2019. Without this, FBC's actual rate performance over the Current PBR Plan term would have been even better than portrayed in Figure B2-5. At the end of the Current PBR Plan term, a net balance in the 2018-2019 Revenue Surplus deferral account of $4.840 million (before tax) is still available to customers for future rate mitigation or smoothing

2.3.5 Analysis of Strengths and Weaknesses

MRP designs and their regulatory ramifications are dynamic in nature and may evolve based on their performance in dealing with existing challenges and their ability to respond to future utility needs. Therefore, it is essential to analyse existing plans' strengths and weaknesses and apply the appropriate modifications based on experience with the last rate plan. The review of MRP developments in other jurisdictions also indicates that all regulators and utilities have consistently strived to improve their respective MRP designs to prepare the utilities for future challenges and to realign the interests of utilities and their customers.

As indicated in previous sections, despite some challenges related to capital formulas, both FEI's and FBC's plans have resulted in O&M expenditure savings as well as average rate increases at or below the level of inflation over the term of the plans. Further, the Current PBR Plans' safeguard mechanisms performed as designed and mitigated the consequences of the capital pressures experienced. Nevertheless, a critical review of the Current PBR Plans' performance indicates that some modifications are necessary for the future ratemaking period. A brief discussion of the Current PBR Plans' key strengths and weaknesses is provided in the sections below.

2.3.5.1 Current PBR Plans' Key Strengths

<u>Indexed O&M formula</u>

The evaluation of FEI's and FBC's O&M expenditures during the term of the Current PBR Plans indicates that O&M expense is a suitable candidate for an indexed-based formula and can incent the Companies to optimize their operational expenditures. FEI's and FBC's O&M expenditure performance has been a success in almost every category – less than inflation, O&M per customer has declined, and strong performance relative to other utilities[66]. As such, it is reasonable to assume that a similar approach to O&M expenditures in future MRP designs would be appropriate.

[66] Evidenced by annual and cumulative O&M savings compared to formula and the embedded productivity factor (Tables B2-2 and B2-3), and declining O&M unit cost trends both in absolute (Figures B2-1 and B2-2) and relative (Section B2.4.3 below) terms.

Safeguard Mechanisms:

The Current PBR Plans include several safeguard mechanisms to mitigate the risks of unintended and/or unexpected events during the Plans' term. These include the earning sharing mechanism, the capital dead band, the off-ramp provisions as well as the exogenous factor treatment. FEI concludes that these mechanisms have been generally successful in fulfilling their purposes and should be maintained in future MRPs, although some modifications to improve administrative efficiency and ease of understanding might be appropriate.

The ESM has been a successful and non-contentious part of the Annual Review proceedings and was used to share the achieved benefits equally (align interests) between the Utilities and customers in each year. Nevertheless, the ESM calculation methodology will benefit from changes to improve its ease of administration and understanding, and in consideration of other changes to the MRPs. The proposed changes to ESM are discussed in Section C8.8.2.

Similarly, the capital dead band provision proved to be a significant element of the existing plans and mitigated the risks of FEI and FBC exceeding their formula-driven capital expenditures limits. As designed, the capital dead band provision would also have mitigated the risks to customers had capital expenditures fallen significantly below the formula-driven capital expenditure limits, such as what occurred in FEI's 2004-2009 PBR Plan. However, the overall mechanism and its related calculation methodology were not well understood by interveners and were a source of a number of questions in Annual Review proceedings. FortisBC concludes that the capital dead band treatment operated as intended. However, given the proposed changes to the capital cost determination (use of forecast for the majority of the Companies' capital costs), the capital dead band mechanism is no longer required, and other safeguard mechanisms can provide sufficient protection to the Companies and their customers.

The exogenous (Z-Factor) mechanism is another safeguard mechanism for treatment of exogenous cost items that are outside the control of the Utilities. In the most recent Annual Reviews for example, both Companies applied for and received approval of Z-Factor treatment of the 2019 Employer Health Tax and 2018 and 2019 Medical Service Plan premium reductions, both of which resulted from changes in government laws and regulation. FortisBC, however, reiterates that the inclusion of a materiality threshold on Z-Factor treatment of unexpected and non-controllable costs may prevent the Utilities from recovering their prudently incurred costs and should be discontinued. FortisBC's proposed criteria for exogenous factor considerations are discussed in Section C4.10.

Finally, the off-ramp provision is an important last resort mechanism to protect utilities and ratepayers against any potential unintended consequences of MRPs (such as windfall surplus or losses). Although FEI's and FBC's other safeguard mechanisms ensured that this last resort tool was not used, the triggering of off-ramp provisions in other jurisdictions (such as for ATCO Gas and ATCO Electric)[67] are reminders of the importance of this regulatory protection.

Service Quality Indicators

FEI's and FBC's Current PBR Plans include a number of targeted and informational SQIs. The SQIs are considered to be an important part of any MRP to ensure that any achieved cost savings are not at the expense of reduced service quality. The review of annual SQI results, as presented in multiple Annual Reviews and Appendices C5-1 and C5-2, indicates that both Utilities have met their service quality targets in almost all of the years. FortisBC believes that the tracking and monitoring of SQIs and the existing approach for setting service quality targets have been successful and should be maintained. Nevertheless, SQIs should be reviewed periodically to ensure the metrics and benchmarks remain appropriate. The Companies have done so in Section C7.

Flow-through of Variances

Under the Current PBR Plans, all variances from the costs (and revenues) embedded in rates are recorded in deferral accounts and are returned to or recovered from customers in subsequent years' revenue requirements (with the exception of variances in formula O&M expense and ROE related to formula capital expenditure variances included in the ESM). This treatment provides certainty of cost recovery for the Utilities, but less incentive for cost reduction. FortisBC is proposing to increase the incentive properties of these Proposed MRPs compared to the Current PBR Plans by treating controllable costs as shareholder risks, while variances in non-controllable costs and revenues will continue to flow through to future rates.

The treatment of variances from forecast for each cost and revenue item is set out in Section C4 Annual Calculation of Revenue Requirements.

2.3.5.2 Plans' Key Weaknesses

Capital Formulas

As discussed in Section B2.2.2.2, the capital-related formulas for both FEI and FBC did not provide sufficient funding to support the Companies' investment needs and, as a result, actual capital expenditures exceeded the formula-driven amounts in each year of the PBR term[68]. It is evident that without the appropriate safeguard mechanisms in place, both Utilities would have endured significant financial difficulties in funding the required capital programs during the Current PBR Plans' terms. The review of the reasons for these large variances (as provided in Appendix B8-1 and B8-2) indicates key lessons that need to be considered in future MRP designs.

[67] 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 (AUC's first generation PBR decision) as both utilities passed the materiality thresholds that were determined for triggering the re-opener provisions.

[68] With the exception of FEI's 2015 sustainment and other capital.

First, the proposed capital expenditures for the base years (if a formula is used) or the forecast years (in case of a forecast MRP) should not be changed through averaging or other purely mathematical computations. Rather, the assessment of the reasonableness of the Companies' base or forecast should rest on a careful review of assumptions and scenarios considered.

Second, considering the long-standing forward test year approach in BC's regulatory framework, the capital forecasts and/or formula elements should be based on forward looking indicators. Reliance on lagged growth and inflation factors, or the use of historical test years, are inappropriate and can lead to insufficient funding.

In conclusion, based on the feedback received (discussed in Section B2.2.4) and considering the shortcomings of the existing capital formulas in providing sufficient funding, a change from the I-X mechanism for capital expenditures is warranted. FortisBC submits that its proposed changes for the Proposed MRP as presented in Sections C1 and C3 will properly address these key points and will limit the risk of large variances while continuing to incent the proper management of capital expenditures.

<u>Promoting Innovation</u>

The Current PBR Plans were mainly focused on achieving cost efficiencies and reducing the regulatory burden. While this focus led to sizable benefits to ratepayers, it was not designed to prepare the Utilities for long-term challenges[69]. Regulators in other jurisdictions have recognized that traditional ratemaking models can be complemented with alternative incentive frameworks to encourage innovation and have approved targeted incentives to promote innovative solutions to traditional utility challenges in their jurisdictions. For instance, a recent paper by Dr. Jeff Makholm published in the Electricity Journal indicates that many U.S. based utilities are moving beyond the mere cost reduction perspective to incentive regulation and are embracing other incentive frameworks that can better promote innovation and prepare for the "Utility of Future"[70]:

> 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 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 earning returns on expenses); and (2) earning returns on targeted outcomes.

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69 In other words, the Current PBR Plans were mainly focused on improving Utilities' productive and allocative efficiencies but was less focused on dynamic efficiency.

70 Appendix C4-1; Jeff Makholm; "The rise and decline of the X-Factor in performance-based electricity regulation", The Electricity Journal 31 (2018) 38–43; PP.42-43.

Both FEI and FBC have a number of strategic long-term initiatives that are currently treated outside the PBR framework. FEI, for example, has been a North American leader in RNG and NGT related technologies and has introduced a number of unique innovations to these developing fields. For instance, FEI is the first company in the world to offer a truck-to-ship on-board LNG bunkering system. The new MRP design can, and in FortisBC's view should, include a series of targeted incentives to encourage these innovative solutions and properly incent the accomplishment of government energy policies (please refer to Sections C3.3.7 and C6 for more detail).

2.4 *BENCHMARKING STUDY*

2.4.1 Direction to Conduct Benchmarking Study

On page 82 of the FEI 2014 PBR Decision and pages 79 and 80 of the FBC 2014 PBR Decision, the BCUC directed FEI and FBC to prepare benchmarking study as follows:

> 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.**

2.4.2 Stakeholder Consultation Process

As directed, FortisBC developed and carried out a consultation process with interested stakeholders with the objectives to select a mutually acceptable consultant to conduct the benchmarking study and to reach an agreement on broad terms and parameters of the study (i.e., Terms of Reference). Stakeholders that participated in the consultation process included:

- B.C. Sustainable Energy Association (BCSEA);
- B.C. Pensioners' and Seniors Organization (BCOAPO);
- Commercial Energy Consumer Association of B.C. (CEC);
- MoveUP (Canadian Office and Professional Employees Union, Local 378, known as Movement of United Professionals);

- Irrigation Ratepayers Group (IRG);
- Industrial Customer Group (ICG); and
- B.C. Municipal Electrical Utilities (BCMEU).

In addition to the stakeholders listed, consistent with the BCUC directive, FortisBC kept BCUC staff informed of developments.

The following is a discussion of FortisBC's efforts from the initial consultation sessions with stakeholders to the selection of the consultant for the benchmarking study.

2.4.2.1 April to June 2017 – Outline Benchmarking Study and Solicit Initial Stakeholder Feedback

FortisBC met with stakeholders from April to June 2017 to review the BCUC directive and to explain the requirement for the Benchmarking Study (FEI Benchmarking Study and FBC Benchmarking Study). Stakeholders were asked to provide their feedback and comments on considerations for the benchmarking study. Stakeholders were advised that their comments would be documented and circulated to the other stakeholders and the BCUC staff.

2.4.2.2 May to July 2017 – Summarize Stakeholder Comments

During this time, FortisBC documented stakeholder feedback received on the Benchmarking Study and circulated the documented feedback to each individual stakeholder for their review and confirmation before their comments were circulated to all stakeholders.

2.4.2.3 August to November 2017 – Next Steps for Determining Broad Terms of Reference and Selection of Consultant

On August 29, 2018, in an email to all stakeholders, FortisBC circulated a final summary of stakeholder feedback received during the consultation sessions held and advised of the next steps. The email is provided below for reference.

> Hi everyone
>
> Further to our recent meetings on the required Benchmarking Study as outlined in the BCUC directive, attached is a summary of the stakeholder comments received. Please recall each stakeholder's comments were circulated back to the stakeholder for edit and confirmation before including their comments in this overall summary.
>
> Next Steps
>
> Following are the suggested next steps to finalize the Terms of Reference and narrow down the list of potential consultants to include in a proposed Request for Proposal (RFP) process regarding the benchmarking study.

1. Attached is a document titled "Benchmarking Study Terms of Reference" which outlines some key considerations to include in the Study. Based on a review of prior benchmarking studies undertaken, FortisBC has drafted a set of high level metrics to consider. Measures include those that cover costs (i.e. OM&A) and service levels. Included in the document are suggestions provided by stakeholders for inclusion in the Terms of Reference. Please review the document and provide any suggestions you may have.

2. Attached is a document titled "List of Benchmarking Consultants" which outlines potential consultants for the benchmarking study. Included for your consideration is information about their background, qualifications and experience in preparing benchmarking studies including listing of some of their previous clients. The list of potential consultants was developed based on suggestions provided by stakeholders and consultants which FortisBC has identified. Please review the list and advise which consultants stakeholders "would object to using" for the benchmarking study.

3. In deciding which consultant to select for the benchmarking study, FortisBC proposes the following selection criteria:

    - Consultant's prior experience in preparing similar benchmarking studies for electric and natural gas distribution companies;
    - Consultant's approach to normalizing the data to ensure an "apples to apples" comparison; and
    - Cost of the benchmarking studies (FortisBC Energy Inc. and FortisBC Inc.).

   Additionally, the consultant is expected to provide commentary as required on the study's results, explaining any differences and contributing factors.

4. Please provide your suggestions and feedback to Steps 1 – 3 above **by Tuesday September 12.** [bold in original]

   On receipt of your suggestions and feedback, FortisBC will initiate the RFP process and select the benchmarking consultant.

In the email, stakeholders were advised to provide their feedback on the proposed Terms of Reference developed by FortisBC for the Benchmarking Study. Based on a review of prior benchmarking studies undertaken, and consideration of stakeholder comments received, FortisBC drafted a set of high level and balanced metrics for stakeholders to consider. Measures included those that cover both costs and service levels.

Additionally, stakeholders were asked to provide their feedback on a list of possible consultants to consider by stating which consultants they "would object to using" for the Benchmarking

Study, instead of which consultants they would prefer. Recognizing the challenges experienced in the review of the PBR Application, FortisBC believed that identifying consultants that stakeholders “would object to using” may minimize the clash of methodologies and lead to a list of acceptable consultants to use for the RFP process. Information on the potential consultants’ background, qualifications and experience in preparing benchmarking studies, including listing some of their previous clients was provided by FortisBC to assist stakeholders with their review process.

To decide which consultant to select for the Benchmarking Study, FortisBC provided the following selection criteria:

- Consultant’s prior experience in preparing similar benchmarking studies for electric and natural gas distribution companies;
- Consultant’s approach to normalizing the data to ensure an “apples to apples” comparison; and
- Cost of the benchmarking studies.

Additionally, the consultant was expected to provide commentary as required on the Study’s results, explaining any differences and contributing factors.

Upon receipt of stakeholder suggestions and feedback, FortisBC would initiate the RFP process and select the benchmarking consultant. All stakeholders provided their comments by the end of October 2017.

In November 2017, FortisBC met with BCUC staff to review stakeholder comments and advise of the proposed Terms of Reference and list of consultants to be included in the RFP process.

2.4.2.4 December 2017 to February 2018 – RFP Process and Selection of Consultant

FortisBC initiated the RFP process in December 2017.

Proposals received were evaluated, resulting in the selection of Concentric as the consultant for the benchmarking studies. Concentric’s proposal addressed the Terms of Reference as outlined by FortisBC. Concentric has experience with benchmarking studies, was familiar with FortisBC and has a broad and diverse knowledge of utilities across Canada. FortisBC advised BCUC staff in late January 2018 prior to awarding the benchmarking study to Concentric.

FortisBC requested a separate study be prepared for FEI and for FBC.

2.4.2.5 November 2018 – Benchmarking Study Workshop

A workshop was held on November 13, 2018 to provide an update and for Concentric to discuss the results of the Benchmarking Study. Minutes of the workshop are included in Appendix C2-4.

2.4.3 Highlights of the Benchmarking Study

2.4.3.1 FEI Benchmarking Study

The following is an extract from the FEI Benchmarking Study, p. 35 to 38, which provides an overall summary and highlights of the Study. Refer to Appendix C2-1 for the complete FEI Benchmarking Study prepared by Concentric.

Summary and Conclusions

The Study focused on a series of metrics designed to examine the relative efficiency of FEI 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 FEI's performance.

The Study focused on benchmarking metrics that measure financial efficiency, reliability, and customer service performance. These metrics were chosen in consultation between FEI and 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 B2-6: Summary of Benchmarking Analyses for FEI

% 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 is better (i.e., results at or below the peer group median) at the broadest expense level analyzed (i.e., distribution O&M plus total Administration and General (A&G) expenses) on a per customer, per volume, per employee, and per kilometre of distribution mains basis, as well as FEI'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 (telephone service factor or TSF-non-emergency and CO_2 emissions per volume). For two of the factors (i.e., TSF – emergency and first contact resolution or 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, FEI's OM&A and net plant have increased modestly over the period studied on a nominal basis (five-year compound annual growth rates or CAGRs of 0.75 percent and 1.36 percent, respectively), and have decreased (in the case of operations, maintenance, and administrative or 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 percent). On a relative basis, FEI 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 terajoule (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 FEI 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 FEI's benchmarked results.

2.4.3.2 FBC Benchmarking Study

The following is an extract from the FBC Benchmarking Study, p. 35 to 39, which provides an overall summary and highlights of the Study. Refer to Appendix C2-2 for the complete FBC Benchmarking Study prepared by Concentric.

Summary and Conclusions

The Study focused on a series of metrics designed to examine the relative efficiency of FBC 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 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 FBC's performance.

The Study focused on benchmarking metrics that measure financial efficiency, reliability, and customer service performance. These metrics were chosen in consultation between FBC 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 B2-7: Summary of Benchmarking Analyses for FBC

% 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 (System Average Interruption Duration Index or SAIDI, System Average Interruption Frequency Index or 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 FBC'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 percent 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 FBC's performance-based ratemaking benchmark of 70 percent 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 percent 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 FBC'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, FBC's OM&A and net plant increased modestly over the period studied on a nominal basis (five-year CAGRs of 2.08 percent and 2.95 percent, respectively), and increased by less than 1.00 percent year-over-year on a real basis (based on a five-year average annual increase in the Consumer Price Index of 1.39 percent). On a relative basis, FBC 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 megawatt hour 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 FBC 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 FBC's benchmarked results.

2.4.4 Summary

Based on the results discussed earlier in Section 2.1.3.1 O&M Expenditures and the results reported by Concentric for the set of high level and balanced metrics used for the Benchmarking Study that covers both costs and service levels, FortisBC believes that FEI and FBC are operating efficiently relative to their peers, and in comparison to the efficiency that existed in 2013.

For FEI's performance on a stand-alone basis over the period studied, FEI's OM&A and net plant have increased modestly on a nominal basis and have decreased (in the case of OM&A) or remained flat (in the case of net plant) on a real basis. On a relative basis, FEI performed at or better than the peer group median in the majority of the financial metrics analyzed.

For FBC's performance on a stand-alone basis over the period studied, FBC's OM&A and net plant increased modestly on a nominal basis and increased slightly year-over-year on a real basis. On a relative basis, FBC performed at or better than the peer group median in the majority of the expense-related metrics analyzed.

2.5 *INTERVENER DISCUSSIONS AND FEEDBACK*

In its efforts to develop this Proposed MRP Application that recognizes the interests and issues of concern of interveners, FortisBC engaged in a number of discussions with interveners in 2017 and 2018. Following is a summary of the discussions.

April to June 2017 – Efficiency Benchmarking Study and Next Generation Rate Making Approach

FortisBC representatives met with interested interveners on a number of topics as outlined in the agenda below, with the focus on the development of the Next Generation Rate Making application.

Topics included on the agenda were:

- 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 proceeding)
- Discussion of options for rebasing
- Other?

Material used by FortisBC to facilitate the discussion were provided and is included in Appendix C3-3.

FortisBC welcomed the opportunity to hear interveners' initial thoughts on the Companies' Next Generation Rate Making application and a review of the Current PBR Plans' performance. FortisBC representatives met with representatives from BCSEA, BCOAPO, MoveUP, CEC, ICG, IRG and BCMEU during the period April to June 2017.

Some interveners indicated that the Current PBR Plans were working well and were satisfied and that SQIs were being managed, whereas other interveners noted concerns about the Current PBR Plans. The concerns raised included PBR plans in general and whether savings being realized were attributable to the Current PBR Plans and also that the Current PBR Plans focus too much on efficiencies and savings.

For the next Rate Making Plan, an intervener commented that the Companies need to address the capital spending / incentive and find an appropriate balance between service levels to meet customer expectations and reducing costs to improve profits. It was asked whether the Companies were considering excluding capital from the framework. Another intervener commented that the PBR approach is just another way of determining customer rates and that It is a reasonable approach. Noted in the discussions was that the simplicity of Current PBR Plans is preferred. Some discussion occurred regarding rebasing: why it is required and what would be the basis for rebasing (i.e., actuals, forecast, etc.).

October 2018 – Update on FortisBC Next Generation Rate Making Approach

FortisBC representatives met with interested interveners to share some key themes of the planned Next Generation Rate Making application, what FortisBC was planning, and the timing for the upcoming application. Additionally, FortisBC welcomed the opportunity to hear interveners' thoughts and concerns that they may have about our Next Generation PBR application. FortisBC representatives met with representatives from BCSEA, BCOAPO, MoveUP, CEC, ICG, BCMEU and BCUC staff during the month of October 2018.

Topics included on the agenda were:

- Highlights of the Current PBR Plans
- Next Generation PBR Application
- Key Themes
    - Engagement
    - Investment
    - Innovation
- PBR Questions and Discussion
- Benchmarking Study Update

Material used by FortisBC to facilitate the discussion was provided and is included in Appendix C3-1.

An intervener commented that the O&M savings incentive has worked poorly as it is rewarding the Companies for initiatives that they would be doing outside of a PBR. Additionally, the intervener suggested that there needs to be 'boundaries' established for defining what is exceptional performance for which the Companies should be rewarded. The boundaries could possibly be applied to revenues, in addition to costs. Another intervener expressed a preference for a cost of service approach to the next ratemaking agreement whereas another expressed no preference for either approach. An intervener commented that the next ratemaking agreement would be considered a success if the rate increases were kept to inflation. An intervener expressed a desire to improve reliability for wholesale/municipal customers as loss of supply was a concern and asked FortisBC to consider including a reliability SQI in its next PBR to measure reliability for wholesale/municipal customers on FortisBC's electric distribution system. Most interveners were supportive of the Companies' focus on reducing carbon emissions while recognizing the importance of the balance between achieving low emissions and affordability.

November 2018 – Benchmarking Study Workshop

FortisBC representatives met with interested interveners for a workshop, with the focus for Concentric to share the highlights of the Benchmarking Study and discuss any questions and comments.

Material used by Concentric to facilitate the discussion was provided and is included in Appendix C2-3.

For a discussion of the highlights of the Benchmarking Study, refer to Section B2.4.3 of this Application.

In addition to sharing the highlights of the Benchmarking Study, the workshop provided another opportunity for interveners and FortisBC to consider the next ratemaking application in the context of the Benchmarking Study results.

December 2018 – Review of Multi-Year Year Rate Plans and Cost of Service Regulation Workshop

FortisBC organized a workshop for interested interveners, with the focus to review the merits of multi-year rate plans, compared to cost of service regulation. Recognizing some stakeholders' comments expressed about FortisBC continuing with another PBR type arrangement in the future, an objective of the workshop was to provide context and be helpful to stakeholders in reviewing and understanding FortisBC's upcoming ratemaking application. Additionally, the workshop was an opportunity for stakeholders to discuss PBRs as a group and to communicate concerns about PBR. To facilitate the workshop, FortisBC engaged Dr. Lawrence Kaufmann. Dr. Lawrence Kaufmann is the President of Kaufmann Consulting, a Senior Advisor to Pacific Economics Group and Navigant Consulting, and a Fellow at the Canadian Energy Research Institute. Dr. Kaufmann's primary responsibilities include developing and undertaking supporting empirical research on alternative regulation approaches and competitive market reforms for energy utilities.

Interveners attending the workshop included representatives from BCOAPO, MoveUP, CEC, ICG, Nelson Hydro and BCUC staff.

Material used by FortisBC and Dr. Larry Kaufmann to facilitate the discussion was provided and is included in Appendix C3-2.

As part of the workshop preparation, FortisBC circulated an online survey to stakeholders asking the following questions:

1. 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?
2. 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)
3. 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)
4. Please rank the following topics from the greatest interest to the least interest for workshop discussions.
5. 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 Innovative Technologies.

A summary of the responses is provided below. As FEI received only three complete responses, the value of the survey results is limited.

Of the three complete responses to question 1, two responses were that utilities have a mandate to be efficient and do not need additional incentives to do so. One response agreed that utilities should be incented to be more efficient and promote innovative solutions to utility challenges.

The responses to questions 2 and 3 on rating the effectiveness of performance-based and cost of service regulation in achieving regulatory objectives varied with ratings received ranging from 1-Not Effectively to 5-Very Effectively for the regulatory objectives listed. For the objective “incentive for O&M savings”, two responses suggested that PBR was effective (rating 4). For cost of service’s effectiveness in “incentive for O&M savings” two responses rated cost of service as effective (i.e., one rating of 4 and one rating of 5). For the objective regulatory efficiency, the responses also varied. When asked how effective was PBR in regulatory efficiency, two responses indicated effective (rating 4) with one response suggested PBR was ineffective (rating 1). When asked to rank the same objective from a cost of service perspective, two responses indicated effective (one rating of 5 and one rating of 4).

The response to question 4 showed topics of greater interest include “Fundamental comparison of cost of service rate setting and MRP rate setting”, “Type of multi-year rate plans (revenue cap, price caps, customer plans, …) and I-X indexing formulas”, “Service quality indicators”, and “Term: longer duration of MRP plans”.

The responses to question 5 showed general support and willingness from customers in paying to support Innovative Technologies.

Refer to Appendix C3-2 for details of responses received from stakeholders.

The following are some highlights and comments captured regarding Cost of Service versus PBRs agreements during the workshop. During the workshop, some interveners expressed concern about FortisBC’s intention to file another PBR and that the Companies were not open to another type of ratemaking agreement. Reservations were expressed by the interveners on the appropriateness of another PBR. Another intervener commented that neither a cost of service or PBR-type model meets the needs of the current situation. Climate change and the requirement for low carbon emissions is a predominant issue that will be challenging for the utility to transition successfully through. The intervener suggested that this is the time to take a timeout to design the structure and framework to help the utility transform itself. Debate occurred amongst participants concerning why Cost of Service is prevalent in some jurisdictions and not other jurisdictions. During the discussion, an intervener asked Dr. Kaufmann whether it was easier for the Companies to manipulate the results under a Cost of Service or PBR agreement. Dr. Kaufmann responded that it is possible under both forms of ratemaking. The intervener questioned the value of the Current PBR Plans and suggested that an evaluation be performed before the next ratemaking agreement is considered.

In addition to the above feedback provided by interveners regarding FortisBC’s next ratemaking application, interveners have also provided comments as part of the recent Annual Reviews and as part of the request by MoveUP for a Section 82 Inquiry Request of the UCA. Following are some of the highlights of the interveners comments provided.

October 2018 FEI Annual Review for 2019 Delivery Rates

Regarding the performance of the Current PBR Plans, MoveUP highlighted that the only “significant negative” was the “utility’s inability to maintain capital within bounds….”. Otherwise, FEI has demonstrated that it is able “to check virtually all of the boxes…..”.

> General Observations
>
> 1. FEI has demonstrated in this Annual Review that it is able to check virtually all of the boxes currently presented by the 2014-19 PBR. It proposes to hold rates steady through the next year. It has managed to squeeze out a small trickle of available funds for earnings sharing, albeit on a trivial scale. It has managed to clear the Service Quality Indicator hurdles, meeting or exceeding the prescribed targets.
>
> 2. The only significant negative has been the utility's inability to maintain capital spending within bounds, a pattern that has been consistent through the latter years of the PBR cycle. FortisBC has indicated that it will seek to address the difficulties presented by the capital formula when it files its proposal for a second consecutive PBR cycle in 2019.[71]

The BCMEU acknowledged that there have been positive O&M savings for the benefit ratepayers but expressed concern about capital expenditures:

> The BCMEU remains concerned, as do other participants in the proceeding, about the significant variance in formula capital expenditures, particularly in the later years of the PBR. The BCMEU submits that this will be an important area for review and assessing whether a future PBR model should be implemented.[72]

MoveUP, however, stated concern about the value of the Current PBR Plans and whether the same results could have been achieved under a different regulatory structure:

> 4. MoveUP submits that it is difficult to detect any material benefit for ratepayers, or the public interest generally, flowing from the PBR – that is, specific and concrete gains that would not have been just as available under a more traditional regulatory cycle. The utility is unable to identify any specific benefits of that nature, and neither are we.[73]

Noting also concern about the value of the Current PBR Plans, CEC in its final argument stated:

> 14. The CEC submits that when evaluating the PBR it will be important for the Commission to make a clear determination as to the costs and benefits that accrued to ratepayers under the current PBR, and also to determine whether or not these costs and benefits were a direct result of the ratemaking mode.[74]

CEC also recommended there be a separate process to assess the results of the Current PBR Plans:

71 FEI Annual Review for 2019 Delivery Rates, MoveUP Final Argument, p. 1.
72 FBC Annual Review for 2019 Rates, BCMEU Final Argument, p. 2.
73 FEI Annual Review for 2019 Delivery Rates, MoveUP Final Argument, p. 2.
74 FEI Annual Review for 2019 Delivery Rates, CEC Final Argument, p. 3.

17. The CEC recommends that prior to advancing a new PBR, the Commission provide for a separate and distinct review process of the existing PBR, which can summarize the full set of evidence and provide comprehensive assessment before commencing the next stage of regulation.[75]

While CEC expressed a need for a separate proceeding to review the performance of the Current PBR Plans, BCSEA indicated their intention was to wait for FEI's future PBR proposal to provide a point of reference for comparison:

> BCSEA-SCBC intend to focus on the future PBR proposal as the point of reference for analyzing the pros and cons of 2014-2019 PBR Plan.[76]

BCOAPO expressed similar concern about FEI proposing another PBR and stated:

> Our clients share MoveUP's healthy skepticism regarding the "superiority of PBR over cost-of service" regulation. That is not to say it is never a good idea, but it is manifestly unclear at this time whether it is realistic to assume there will be any public support for another PBR term immediately after this one ends. BCPIAC suggests that cost-of- service (one year or multi-year) or a modified and much more limited PBR plan that indexes only O&M revenues (with capital spending determined/approved in a mini-hearing) are two alternatives worth considering for the "next generation."[77]

Regarding the value the Current PBR Plans, ICG noted a similar concern as expressed by some of the other interveners:

> <u>Conclusion</u>
>
> As the ICG had anticipated in previous submissions, FBC has not yet provided any evidence that savings, if any, have been achieved that also can be attributed to the PBR Plan.[78]

Also in its final argument, MoveUP commented and agreed that it is likely that there are less realizable efficiencies for FEI to pursue in its next ratemaking agreement:

> **Prospects Looking Forward: "Low-Hanging Fruit"**
>
> 9. The rationale for a further PBR term becomes much weaker in light of the decayed availability of realizable efficiencies. This is particularly the case given Fortis' own acknowledgment, in response to a series of MoveUP IRs, that (as we put it) the "low-hanging" efficiency opportunities were harvested early in the 2014-19 PBR, and that significant further gains are getting

75 FEI Annual Review for 2019 Delivery Rates, CEC Final Argument, p. 3.
76 FEI Annual Review for 2019 Delivery Rates, BCSEA Final Argument, p. 2.
77 FEI Annual Review for 2019 Delivery Rates, BCOAPO Final Argument, p. 11.
78 FBC Annual Review for 2019 Rates, ICG Final Argument, p. 5.

> thinner on the ground, and that there is little basis to expect that this trend would not continue into a second consecutive PBR cycle.[79]

2018 MoveUP Request for Section 82 Inquiry into Regulatory Mechanisms

In its letter dated December 21, 2018 requesting an Inquiry pursuant to S 82(1)(a) of the UCA to review the appropriate objectives for the regulation of FEI, in particular, and how best to achieve them, MoveUP suggested that the traditional focus of prior ratemaking agreements has been on achieving improvements in operating efficiency and controlling capital spending while maintaining service quality and asked whether they should remain the highest priority in light of emerging opportunities and risks facing the utility and ratepayers.

Both of these modes of rate-setting, as traditionally structured in British Columbia, are primarily aimed at achieving incremental improvements in operating efficiency and disciplined capital spending, while maintaining service quality. However, there has been no updated analysis of whether those should remain the highest regulatory priorities in light of emerging opportunities and risks facing the utility and its ratepayers. That analysis should guide the BCUC's decisions over the coming period: what to measure, what to incent, what to permit, what to require, and what to prohibit. The CEC in its comments supported MoveUP's view and the issues raised that may impact FEI's future:

> 5. The CEC is of the view that the potential for disruptive change occurring in the next several years is significant, and agrees that the issues raised by MoveUp are worthy of specific Commission attention. Indeed, the CEC has raised the issue of FEI's future in the face of increasing climate change many times over the last several years.[80]

The ICG commented that it did not comment on regulatory matters related to FEI, and does not take a position regarding the request of MoveUP for an inquiry:

> Specifically, the ICG did not and does not take a position regarding the request of MoveUp for an Inquiry pursuant to section 82(1)(a) of the *Utilities Commission Act*, which the ICG believes is the subject of the Commission letter dated December 31, 2018.[81]

The BCMEU commented that concerns about climate change is a matter of Provincial Policy and addressed at that level:

> In reference to concerns about climate change as GHG-emitting energy resources are curtailed and we have the transformation of utilities as we know

79 FEI Annual Review 2019 Delivery Rates, MoveUP Final Argument, p. 3.
80 2018 MoveUP Request for Section 82 Inquiry into Regulatory Mechanisms, CEC comments, p. 1.
81 2018 MoveUP Request for Section 82 Inquiry into Regulatory Mechanisms, ICG Comments, p. 1.

> them, perhaps this should be a matter of Provincial Policy and addressed at that level.[82]

In its Decision dated February 1, 2019, the BCUC declined to initiate an inquiry at this time:

> While the BCUC acknowledges that MoveUP has raised important issues in its submissions, we decline to initiate an inquiry at this time. We further note that based on the submissions received on MoveUp's request, none of the other stakeholders expressed support for the BCUC initiating an inquiry.
>
> The BCUC's role in the regulation of public utilities is defined by the UCA. We are confident that there are appropriate regulatory processes within our mandate to addresses the concerns raised. Issues that impact utilities over the longer term are addressed in our review process for FEI's most recent Long-term Resource Plan, which concluded on December 20, 2018 with a BCUC decision pending at this time. We note that MoveUP has not participated in this process.
>
> We are continually looking at external factors impacting utilities and we take all necessary steps to remain informed about emerging industry trends so that relevant issues may be explored in our regulatory review processes.[83]

With regard to the request from some stakeholders for a review of FortisBC's Current PBR Plans' performance before the next rate application, the BCUC also declined and decided that would occur when FortisBC files its rate application in the upcoming months:

> With regard to MoveUP and other stakeholders' comments on rate-setting and a review of FortisBC's PBR Plans, if, and when, a rate application is filed by FortisBC in the upcoming months, we welcome MoveUP and other parties to participate in that process and bring forward any alternative rate setting proposals to be reviewed and considered at that time.[84]

2.6 *REVIEW OF OTHER JURISDICTIONS*

In the last two decades, various Canadian regulators have employed indexed-based MRPs for the regulation of natural gas and electric utilities within their jurisdictions. Currently, in addition to BC, Alberta, Ontario and Quebec apply indexed MRPs to their major local distribution and/or transmission companies. Other North American regulators have also been pushing for alternative incentive frameworks to the traditional cost of service regulation.

This section includes a brief discussion of recent regulatory developments regarding the prevalence of performance-based incentives and multi-year rate plans in North American jurisdictions. It further provides a concise summary of the main features of MRPs approved by

82 2018 MoveUP Request for Section 82 Inquiry into Regulatory Mechanisms, BCMEU Comments, p. 1.
83 2018 MoveUP Request for Section 82 Inquiry into Regulatory Mechanisms, BCUC Letter, pp. 1-2.
84 Ibid. p. 2.

Canadian regulators. In addition to the review of major Canadian MRPs and in response to the feedback received from the BCUC staff and other stakeholders, the jurisdictional comparison section also includes an additional sub-section to review alternative incentive frameworks in two U.S. states.

FortisBC observes that all MRPs included in this study share a set of common objectives in seeking to promote a continuous efficiency focus, align utilities' and ratepayers' interests and encourage utilities to achieve government policy objectives while ensuring service quality requirements are met. Further, all MRPs reviewed aim to create an efficient regulatory process for the period of the MRP, allowing the utilities to focus on effectively managing business priorities and increasing the focus on innovative solutions to utility challenges.

Nevertheless, within the frameworks of these common objectives, each jurisdiction has tailored the plans to fit its specific circumstances. This supports the popular belief among MRP practitioners that there is no one "right" MRP model and that the framework adopted for each utility should be in keeping with their specific circumstances and their history with performance based rate-setting. The following excerpt from Ontario Energy Board (OEB) 2018-2021 Business Plan articulates this issue as follows[85]:

> Although no regulatory model has yet emerged as the preferred "industry standard", other regulators are grappling with many of the same challenges facing the OEB during a period of sector evolution. Those challenges include the setting of utility remuneration to encourage efficiency and innovation, the design of rates to provide appropriate guidance to consumers regarding their own consumption and investment decisions, the mitigation of regulatory barriers to innovation and new business models, and the protection of consumers during sector transformation. The ways in which other utility regulators are addressing these issues reflect the particular institutional arrangements, market structure and broader policy framework prevailing in their jurisdictions. Although the work of other regulators is instructive, the OEB's own approach must be grounded in an appreciation of the circumstances in Ontario and of its own mandate.

In other words, while MRPs in various jurisdictions may share many common features, the overall incentive package is tailored to fit the circumstances of each utility.

2.6.1 Regulatory Support and Prevalence of Incentive Plans in North America

As discussed earlier, both FEI and FBC have had three successful MRPs (for a review of FortisBC's historical MRPs refer to and Appendix C1). The successful results of these plans have been discussed in a number of BCUC decisions. For instance, in FEI's 2012-2013 RRA,

85 https://www.oeb.ca/sites/default/files/OEB-2018-2021-business-plan.pdf; pp.13-14.

the BCUC examined the results of FEI's 2004-2009 PBR plan and concluded that significant benefits were achieved for both ratepayers and shareholders[86].

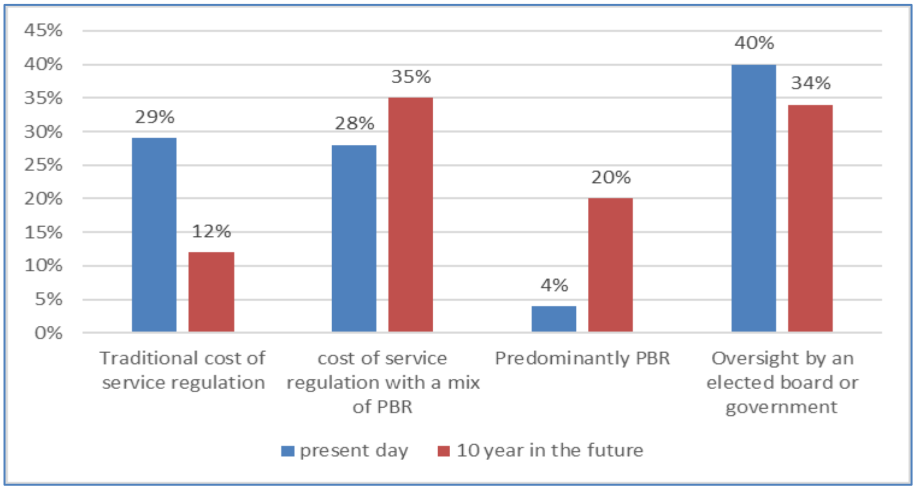
More recently, in BC Hydro's 2017-2019 RRA proceeding, the BCUC raised some concerns regarding BC Hydro's increasing expenditures and BC Hydro's ability to achieve its ten year rates forecast under the existing traditional cost of service regulation and stated that a rate setting mechanism similar to MRPs currently employed by a number of Canadian utilities, and in particular FortisBC's MRPs, could help BC Hydro to accomplish its cost control objectives[87]:

> Performance Based Rate (PBR) setting mechanisms are implemented successfully in many jurisdictions, particularly in Canada, including BC. PBR provides incentives for utilities to improve productivity and create efficiencies to allow for rates to be more effectively managed, while maintaining service quality. Section 60(1)(b.1) of the UCA provides the necessary legislative framework for a PBR plan. FortisBC Energy Inc., a natural gas utility in BC of comparable size to BC Hydro, is currently on a PBR plan which has a term spanning from 2014 through 2019, and was previously on a PBR plan from 2004 through 2009. FortisBC Inc., a vertically integrated electric utility, with generation, transmission and distribution assets, is also currently on a PBR plan with a term spanning from 2014 through 2019. FortisBC Inc. has had two previous PBR plans in the past (1996-2004 and 2007-2011).

Other regulators have also been pushing for increased use of incentive type multi-year rate plans. In Quebec, for example, 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 a rate-setting mechanism to promote efficiency gains for electric utilities (leading to the introduction of the first generation revenue cap plans for Hydro Quebec Distribution and Hydro Quebec Transmission). The regulators in Ontario and Alberta also initiated and approved MRPs for their natural gas and electric distributors (for detailed information regarding the MRPs in Canada refer to Appendix C4-2). A recent survey[88] of approximately 600 professionals employed by the North American electric utility industry (investor-owned, government-owned and cooperatives) indicated that the majority of respondents expect a move away from cost of service regulation to some sort of performance-based regulation[89]. Figure B2-8 below presents the survey results for the entire sample.

86 BCUC Order G-44-12, Reasons for Decision, page 22 and page 34.
87 BCUC Order G-47-18, p.110.
88 Utility Dive, 2017 State of the Electric Utility Survey Report.
89 In some of these jurisdictions, the PBR is not an indexed based MRP but rather a forecast MRP with some targeted incentives and/or reforms to cost of service model.

Figure B2-8: Survey Results Regarding the Future Outlook for Utility Regulation



The respondents for investor-owned utilities had a higher expectation of PBR type regulation, with only 11 percent choosing cost of service regulation as their expected regulatory model in ten years. Government oversight is most common among municipal utilities and co-ops.

The MRPs approved or considered in these jurisdictions can range from forecast multi-year rate plans with outcome-based positive earning opportunities through targeted incentives to fully indexed-based MRPs in the form of revenue or price cap indexes. The majority of plans, however, are hybrid plans with both traditional cost of service and incentive-based approaches working in alignment. Some jurisdictions with lumpy and variable capital expenditures for example may adopt a forecast cost of service approach for their capital investments while applying an indexed-based approach to their O&M expenditures. In the following sections, the main features of MRPs in major Canadian provinces as well as alternative incentive frameworks in two U.S. states are discussed.

2.6.2 Features of Indexed-based MRPs in Canada

This section includes a summary comparison of MRP features and related regulators' decisions in three Canadian jurisdictions. Specifically, Table B2-9 below provides a snapshot of Alberta's second generation PBR plans for natural gas and electric distributors, OEB's renewed regulatory framework for Ontario's electric distributors, Enbridge Gas Distribution (EGD) and Union Gas Amalco Incentive Rate-setting plans (IR Plans) in Ontario, and Hydro Quebec Distribution's (HQD) and Hydro Quebec Transmission's (HQT) first generation PBR plans. A more detailed discussion regarding the background information and explanation of MRPs for each jurisdiction is provided in Appendix C4-2 to this Application.

Table B2-9 below provides a comparison of MRPs in other Canadian jurisdictions.

Table B2-9: Jurisdictional Comparison of MRPs

	Alberta Natural Gas Utilities	Alberta Electric Utilities	Union Gas/ Enbridge Gas Amalco IR Plans	Ontario Electric Utilities[90] (Price cap)	Ontario Electric Utilities (Custom IR Plans)	Hydro Quebec Distribution /Hydro Quebec Transmission
Proceeding	Limited AUC initiated multi-utility hearing		Oral hearing	OEB initiated multi-utility hearing		Oral hearing
Term	5 years		5 years	5 years		4 years
Type	Revenue per Customer Cap	Price Cap	Price Cap (Implied Revenue Cap)	Price Cap	Custom IR Plan	Revenue Cap
Formula	$Rates_{t} = Rates_{t-1} * (1 + I - X)$	Revenue per $customer_{t}$ = Revenue per $customer_{t-1} * (1 + I - X)$	$Rates_{t} = Rates_{t-1} * (1 + I - X) + AU$ AU: Avg Use adjustment	$Rates_{t} = Rates_{t-1} * (1 + I - X)$	Could be forecast, formula or both. Usually custom IR Plans include forecast capital and O&M indexed by formula.	$RR_{t+1} = RR_{t} * (1 + I - X + G)$ G: Growth factor (growth in new attachments) HQT formula is only applied to O&M and capital is forecasted.
Inflation	Composite factor of Alberta AWE and Alberta CPI		GDP IPI FDD	Composite factor of Ontario AWE and GDPPI-FDD	Usually the same as price cap but may change on a case-by-case basis	Composite factor of Quebec CPI and Quebec AWE
X-Factor	0.3%		0.3%	0% to 0.6%	0% to 0.6% Can change on a case-by-cases basis	0.3% for HQD; HQT's X-Factor is not determined yet
Earnings sharing mechanism	No earnings sharing		If normalized actual ROE is 150 bps above approved ROE; excess earnings is shared on a 50/50 basis.	No earnings sharing	Will be decided on a case-by-case basis	If (actual ROE – approved ROE) > 100 bps then 75:25 sharing in favour of ratepayers; if the variance is between zero and 100 bps, then 50:50 sharing

90 Ontario's electric utilities can choose from a menu of options which include Price Cap IR, Annual Indexing IR Plans and Custom IR Plans. The table above includes the information related to Price Cap IR Plans and custom IR Plans only. See Appendix C4-2 to this Application for more information regarding the other annual indexing options.

	Alberta Natural Gas Utilities	Alberta Electric Utilities	Union Gas/ Enbridge Gas Amalco IR Plans	Ontario Electric Utilities[90] (Price cap)	Ontario Electric Utilities (Custom IR Plans)	Hydro Quebec Distribution /Hydro Quebec Transmission
Off-ramps / re-openers	+/-300 bps normalized ROE for two consecutive years or +/- 500 bps in one year		+/- 300 bps normalized ROE for one year	+/- 300 bps normalized ROE for one year		Yes, Not finalized yet.
Efficiency carry-over mechanism	Yes, ROE Bonus up to 50 bps		Yes, deferred rebasing for five years	Consolidating utilities can ask for deferred rebasing of benefits for up to ten years		None
Incremental Capital Funding	Yes, TYPE 1: Same treatment as capital trackers (extraordinary and previously not in the utility's rate base, required by a 3rd party) TYPE 2: An incremental capital calculated based on capital-related revenue generated under I-X and the total notional capital-related revenue requirement		Incremental capital module (ICM) similar to the one applied to Ontario's electric utilities	Incremental capital module (ICM) and Advanced capital module (ACM). Criteria: prudence, discrete projects, clearly outside the base rates and for expenditures above the materiality threshold	Not Applicable; Forecasted in the 5 year plan (exceptions may exist)	Only under Z-Factor mechanism meaning for unforeseen events that are outside management control that meet the materiality threshold.
Z-Factor	Yes, unforeseen, outside management control, materiality threshold: dollar value of a 40 bps change in ROE on an after tax basis		Yes, unforeseen events, outside management control, materiality threshold: $5.5 revenue requirement impact	Yes, Materiality threshold: $50K for Revenue required (RR) less than $10M; 0.5% of RR if $10M < RR =< $200 M, $1M if RR > $200M		Yes, unforeseen, outside management control, materiality threshold
Y-Factor	Yes, Includes items such as AESO flow-through items, municipal fees, load balancing deferral accounts, weather deferral account, …		Yes, Includes items such as cost of gas, DSM expenses, Tax variances, LRAM, …	Yes, Includes both commodity and non-commodity related deferral accounts	Yes, Similar to the price cap plan plus as needed to track capital variances	Yes, for known and recurring events, includes DSM, power supply, pension, …
Service Quality Indicators	Yes, Based on AUC's Rule No.2		Yes, scorecard system	Yes, scorecard system		Yes, not finalized yet.

FortisBC draws the following high-level conclusions from the above table:

- With the exception of HQD and HQT's first generation revenue cap plans, all other jurisdictions have a five-year term. However, the MRP term for both Ontario and Quebec includes a one year cost of service for establishing the going-in base rates.
- Most plans cover both O&M expenditures and capital expenditures while allowing for recovery of certain costs outside the formula as incremental capital expenditure, flow-through or exogenous cost items. Ontario's custom IR Plan option, however, is often used by utilities with significantly large and highly variable capital plan profiles not suitable for formulas. Therefore, the capital expenditures under these plans are often forecast. The EGD MRP (prior to amalgamation with Union Gas) and the Toronto Hydro custom IR Plan are two recent examples of this that are included in Appendix C4-2, Jurisdictional Comparison. The HQT MRP also excludes capital investments from formula and uses a forecast instead.
- Both revenue cap and price cap type formulas have been used by natural gas and electric utilities; however, all natural gas distributors' price cap plans include a mechanism to adjust the rates for average use variances and mitigate the demand risk (similar to FEI's revenue stabilization adjustment mechanism) which transforms their plans to some form of revenue cap in practice.
- With the exception of the Union Gas and EGD Amalco Price Cap IR Plans, all plans' formulas include a composite inflation factor consisting of both labour and non-labour price indexes. Further, with the exception of the 0.0 to 0.6 percent X-Factor value range for Ontario's electric distributors, the X-Factor value for all the other electric and natural gas utilities in Alberta, Ontario and Quebec is set at 0.3 percent, inclusive of any stretch factor. There is no particular pattern with regard to the use and design of the earnings sharing mechanism and efficiency carry-over mechanism.
- Most plans include some form of incremental capital funding mechanism outside the I-X formulas to accommodate utilities' capital needs for lumpy and significant capital projects during the PBR term[91]. A review of capital exclusion mechanisms' evolution in other jurisdictions indicate all jurisdictions have faced challenges in treatment of capital expenditures and have strived to improve their capital exclusion mechanisms based on performance in previous generations of the respective PBR plans.
- All plans include safeguard mechanisms to protect the utility and ratepayers against the potential unintended consequences of PBR plans (such as windfall surplus or losses). These can be in the form of earning sharing mechanisms or off-ramps or re-opener mechanisms that are triggered when, for example, the variances between achieved and approved ROEs exceed a certain threshold.

[91] The HQD's plan does not have a separate capital exclusion framework rather the Z-Factor mechanism (subject to meeting the related criteria) can be used to apply for incremental capital.

- All plans include a series of service quality indicators to monitor the reliability and quality of service during the PBR term and ensure that any cost reduction is not achieved at the expense of service quality. In all cases, these service quality indicators are not attached to an automatic reward or penalty mechanism.

2.6.3 Performance Incentive Frameworks in the United States

As noted above, a recent survey of North American electric utility professionals indicated that the majority of respondents expect a move towards some sort of performance-based ratemaking[92]. In many of these jurisdictions, indexed-based or forecast-based MRPs are complemented by a series of performance incentive metrics and/or other outcome-based targeted incentives tied to achieving policy goals and customer satisfaction. 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 aligned with government policy and customers' interests and are designed to "result in more incentive-neutral utility investment decisions between capital and service-based solutions".[93]

This regulatory change is caused and guided by the recent advances in information technology and network operations as well as the public policy push in various U.S jurisdictions for climate friendly and non-traditional utility solutions such as more distributed energy resources (DER) and non-wire alternative (NWA) programs.

California's utility incentive pilot plan for competitive solicitation framework as well as New York's Reforming the Energy Vision (REV) initiative are two recent examples. Both jurisdictions are known for their progressive regulatory environment and exemplify the recent developments in alternative incentive frameworks adopted by US regulators. A brief summary of the major type of incentives included in these two jurisdictions is as follows:

- **Reforms to the traditional cost of service framework:** Under both plans, utilities will be able to retain any savings from deploying less costly DER alternatives in lieu of previously approved capital projects until the next general rate case. The same concept may apply to GHG emission reduction initiatives. Utilities' rate cases may include earning opportunities tied to reducing the cost of achieving the GHG reduction targets.
- **Non-wire alternative programs:** Utilities may receive positive earning incentives for replacing or deferring traditional distribution and transmission investments with less costly DER alternatives. Under California's incentive pilot plan, for example, utilities may earn a 4 percent pre-tax incentive applied to the annual payment to the DER providers. New York's REV initiative also provides targeted incentives for NWA programs. These can be in the form of the capitalization of expenses related to the program development,

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92 In addition to New York and California that are discussed in this section, other U.S. jurisdictions including Minnesota, Rhode Island, Illinois, Ohio and Hawaii are also in the process of designing or implementing similar alternative incentive frameworks.

93 Hawaii PUC; Docket No. 2018-0088; Order No. 35411; p.6.

ROE premiums for achieving specific targets and/or sharing of cost savings with ratepayers.

- **Outcome-based targeted positive incentives:** California, New York and many other states have used performance incentives for years to encourage reliability, customer service and other priorities. The performance metrics like these are designed to ensure that a standard level of a basic service is maintained and often include both negative and positive earning adjustments. The new outcome-based targets approved for REV and other similar plans, however, do not deal with conventional basic service. Rather they address new expectations that could warrant positive incentives, as exemplified by the following statement of New York's Public Service Commission[94]:

> EAMs deal not with conventional basic service but with new expectations. Meeting these expectations will require innovative management and new forms of cooperation with third parties and customers. Meeting the expectations will also require overcoming implicit disincentives that exist in the cost-of-service model. For these reasons, as well as the reasons articulated by Staff, positive incentives may be warranted … Negative adjustments for EAMs should not be routine. Existing negative adjustments for reliability and customer service are intended to deter problems, and the less they are actually imposed, the better for customers. Most EAMs, in contrast, are established for activities with positive value; therefore the more they are awarded, the better for customers. Most EAMs should be constructed so that achieving the maximum award is a desirable result for customers as well as the utility. Negative adjustments should typically be reserved for exceptional instances of inadequate effort or performance.

As an example, the Table B2-10 below provides a summary description of the type of programs that may warrant positive earning opportunities under New York's REV initiative.

Table B2-10: Positive Earning Opportunities Adopted under New York's REV Initiative

Category	Description
System Efficiency	Includes system efficiency targets for both peak reduction and load factor improvement. These are positive only earning opportunities.
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.

94 Case 14-M-0101,"Order adopting a ratemaking and utility revenue model policy framework", p.66. An EAM is an earnings adjustment mechanism.

Category	Description
Interconnection (for projects that are over 50 kilowatts or kW)	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 assess accuracy, fairness and key drivers of failure.
Customer Engagement	Because customer engagement underlines the majority of other outcomes, it does not require an additional incentive. New York PSC may however consider specific customer engagement incentives for adoption and success of innovative utility programs. This could include things like the uptake of optional time of use (TOU) rates or initiatives related to fuel switching (such as EV adoption and ground source heat pump).
Affordability	Proposal related to termination and arrearage metrics in utilities' rate plans may be considered on a case-by-case basis.

A more thorough review of MRPs in each jurisdiction is included in Appendix C4-2 to the Application.

2.6.4 Support for Incentive Properties of MRPs

The benefits of the incentive properties of MRPs are well-recognized by regulators and academic journal articles.

The BCUC's decision in BC Hydro's 2017-2019 RRA commented on the benefits and challenges of PBR plans, concluding that the benefits of PBR can outweigh its disadvantages and recommended to BC Hydro to consider a PBR type model in its future RRA.[95] FortisBC concurs with the BCUC's view that the benefits of MRP outweigh its potential challenges and, as demonstrated by the experience with FEI's and FBC's Current PBR Plans, the elements of a well-balanced MRP can mitigate many of the risks that may arise during the term of the MRP.

The opponents of incentive rate-setting plans often argue that utilities are under a "statutory obligation" to be efficient, and explicit rewards are unnecessary. This argument is premised on the notion that the regulator can mandate the changes that need to occur without additional incentives for the utilities. This argument is flawed due to the following reasons.

First, motivating increased performance through incentives is generally superior to mandating certain performance levels. Weisman and Pfeifenberger (2003)[96] explain this issue as follows:

> This superior performance derives from the fact that incentive regulation, given the greater emphasis on prices rather than earnings, operates more like a fixed price contract in the sense that the regulated firm is limited in its ability to pass

95 BCUC Order G-47-18, p.111.

96 Weisman D., Pfeifenberger J. (2003), "Efficiency as a discovery process: Why enhanced incentives outperform regulatory mandates.", The Electricity Journal 16(1): pp. 55–62.

> cost increases on to consumers in the form of higher rates. This contrasts with strict cost of service regulation that operates like a cost-plus contract.

Further, as explained by New York State's Public Service Commission, the regulatory mandate inhibits innovation and is an inefficient form of regulation[97]:

> 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 the premise of REV. Outcome-based incentives will allow utilities to determine the most effective strategy to achieve policy objectives, including cooperation with third parties and development of new business concepts that would not be considered under narrow, program-based incentives.

Proponents of cost of service regulation may also argue that the benefits accrued to ratepayers during the multi-year rate plans are not the direct result of the MRP incentives and could have occurred under cost of service ratemaking as well. This argument, however, ignores the superior cost reduction incentives of an MRP approach over traditional cost of service regulation. Multi-year rate plans are usually in place for five years while cost of service based revenue requirements are set for much shorter periods (in the case of FEI and FBC, ordinarily for two years). This means that for a company operating under cost of service regulation there is less incentive to invest in long-term, sustainable cost reductions. As indicated in the BCUC's decision in FEI's 2014-2018 PBR Plan proceeding, it may even result in unsustainable savings[98]:

> The COS model has been relied upon in this jurisdiction and others with some success. The interveners may take comfort in the fact that one of its advantages is that it requires more frequent rebasing and hence there is a limit on the time before any sustainable savings directly impact customer rates. However, with COS regulation, there is little incentive to make sustainable efficiency gains and even less so when an investment is required. In fact, perversely, the utility may be incented to make unsustainable savings.

Another advantage of multi-year rate plans over traditional cost of service ratemaking recognized by regulators relates to their higher regulatory efficiency which results in reduced regulatory cost and increased ability for the utility to focus its resources on growing its business (load building opportunities) and increasing efficiencies throughout the organization.

[97] Case 14-M-0101 (May 2016); pp.62-63.
[98] BCUC Order G-138-14, page.14.

A review of the fundamental differences between cost of service regulation and performance-based regulation is provided in Appendix C4-3 to this Application.

2.7 CONCLUSION

Section B2 provides the needed background that underpins the Companies' Proposed MRP proposals. The items covered include a brief summary of the Companies' Current PBR Plans (Section B2.-2.1), an evaluation of the Companies stand-alone and relative performance during the Current PBR Plans' term (Sections B2.-2.2 and B2.-2.3), a summary of the stakeholder engagement and feedback process (Section B2.-2.4), and a review of MRPs in other jurisdictions (Section B2.-2.5). Based on the history and performance of the Companies in previous MRP designs, as well as the insight and experience of other jurisdictions with alternative incentive frameworks, FortisBC has determined that a multi-year rate plan is the best alternative for its upcoming rate-setting framework. The Companies' proposals, discussed in Section C, are built on the key strengths of the Current PBR Plans and adjust the plan elements to address any shortcomings that were identified.

3. IMPLICATIONS FOR THE RATE PLAN

3.1 *INTRODUCTION AND SUMMARY*

To support the continued health of the Utilities, FortisBC's next rate plans must be responsive to changes in our operating environment, our experience with the Current PBR Plans, and stakeholder feedback. As shown in Section B-1, FortisBC needs the flexibility and focus to address the key influences in our operating environment that are becoming increasingly prominent. As shown in Section B-2, our Current PBR Plans have been successful in reducing operating costs, but the opportunities to reduce operating costs are diminishing, and FEI and FBC perform well against industry peer benchmarks in terms of O&M spending. Our stakeholders have also expressed concerns with aspects of our Current PBR Plans, including the diminishing opportunities for operating savings, the capital funding formula and incentive mechanisms, and the need to address energy policy.

In response, the next rate plan should reflect the following key themes:

- A multi-year rate plan framework;
- Stable levels of O&M funding;
- Flexibility to innovate and adapt; and
- Incentive to invest in our future.

To address these themes, the key features of FortisBC's proposed rate plan framework include a five-year term, index-based O&M funding[99], a five-year capital forecast[100], a continued focus on service quality, a mix of traditional and targeted incentives, and an innovation fund.

The key themes and features of FortisBC's proposed rate plan are discussed in more detail below.

3.2 *MULTI-YEAR RATE PLAN FRAMEWORK*

The length of the term was a key benefit of the Current PBR Plans and FortisBC proposes to continue with this approach. A five-year MRP provides both the Utilities and their ratepayers with a number of benefits, including:

- reduced regulatory costs and internal efficiencies associated with the streamlined regulatory process;
- increased utility focus on managing the business with a long-term view; and,
- increased operational flexibility to address the increasing pace and growing scope of energy industry transformation.

[99] O&M base funding includes increases to manage emerging pressures over the 5-year term.
[100] Except FEI growth capital which will remain on a unit-cost basis.

A multi-year plan is also needed to respond to the changes in our operating environment. The nature of the challenges facing FortisBC, particularly those driven by climate policy, are longer-term. While adapting to energy and environmental policy at various levels of government, FortisBC will also continue to provide safe, reliable, and cost effective energy solutions that help meet British Columbia's climate objectives. A five-year MRP supports the need for a longer-term plan by giving FortisBC a longer horizon to maintain a sustained focus on addressing these important issues.

The multi-year plan should also include the flexibility to adapt to our operating environment. Thus, an important component of the framework is an Annual Review process where appropriate adaptations can be discussed and implemented. Additionally, an ability to forecast the evolving and non-traditional parts of the business on an annual basis adds balance between certainty and flexibility. This will help alleviate concerns about locking into an inflexible framework for both the Utilities and their ratepayers.

3.3 *STABLE LEVELS OF O&M FUNDING*

The Current Rate Plans have been successful in driving cost efficiencies in O&M spending. However, there are diminishing returns, as FortisBC has been under I-X rate methodologies for many years, making it more difficult to deliver on cost reduction initiatives. As shown in the benchmarking study discussed in Section B2.4, both FEI and FBC already perform well against industry peer benchmarks in terms of O&M spending. I-X rate methodologies are also best suited to stable environments where cost management is a key concern.[101] FortisBC's operating environment, however, is changing as discussed in Section B1.

While FortisBC will continue to pursue productivity improvements, the rate plan should encourage FortisBC to increase its focus on addressing emerging challenges in its operating environment. To do this, stable levels of O&M funding sufficient to address emerging pressures will provide certainty to support plans and initiatives, and encourage utility management to focus on the efficient allocation of resources within the business over the term of the Proposed MRP. Put simply, this approach promotes a focus towards finding the level of O&M funding that allows the Utilities to focus on "doing more with what we have", in comparison to the more frequent O&M rebasing inherent in COS rate regulation.

[101] Makholm, Jeff D. The rise and decline of the *X factor* in performance-based electricity Regulation. 2018. Page 1: 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.[Emphasis Added]

3.4 FLEXIBILITY TO INNOVATE AND ADAPT

As our operating environment continues to evolve, FortisBC must remain focused on continually improving service to customers through the innovative use of technologies, processes, and products. This is particularly important in light of a growing need for solutions aimed at emissions reductions. A flexible approach that allows FortisBC to innovate and adapt to this change will be key to managing the transition to a lower carbon economy while achieving a balance between affordability and low emissions for current and future customers. Thus, the rate plan should provide the opportunity for innovation and the adoption of new technologies.

3.5 INCENTIVE TO INVEST IN OUR FUTURE

Consistent with the themes set out above, the rate plan must also provide FortisBC with incentives to invest in the future of the Utilities and the customers they serve. While FortisBC must continue to focus on operating efficiently, it must at the same time increase its focus on seeking out growth opportunities. Investing in load growth opportunities in both the traditional and non-traditional parts of the business results in downwards pressure on rates. This is needed to help offset the costs associated with climate policy and meeting emissions reduction targets, as well as the costs to meet the growing need for investment in system integrity and reliability. Continued growth also helps expand FortisBC's ability to provide lower-carbon energy solutions to a broader customer base now and in the future. This is needed to support the transition to a lower-carbon economy and enable FortisBC itself to transition into a lower-carbon future. Thus, the rate plans should provide incentive for FortisBC to continue to invest in the long-term health of the Utilities. This can be accomplished through a mix of traditional incentives encouraging continued focus on productivity improvement, and targeted incentives encouraging an increased focus on growth.

3.6 KEY FEATURES OF THE 2020-2024 RATE PLAN

In alignment with the above themes, FortisBC proposes a rate plan framework with the following key features are:

- **Five-Year Term**: FortisBC is proposing a five-year term for its rate plans, with an Annual Review process to provide some flexibility for the framework is adapted over time.
- **Index-based O&M**: FortisBC proposes an index-based O&M per customer escalated by inflation, which will provide certainty in funding levels and promote a culture of "doing more with what we have".
- **Capital Forecast**: FortisBC is proposing a five-year capital forecast for Growth, Sustaining and Other capital (with the exception of FEI growth capital). FEI is proposing that its Growth capital should be managed on a unit cost basis as it remains well suited to this approach.
- **Incentives**: FortisBC is proposing a mix of traditional and targeted incentives in the rate plan framework. Traditional incentives ensure a sustained focus on core parts of the business while targeted incentives serve to align interests in achieving climate objectives

while also investing in the future of the business through traditional and non-traditional load growth opportunities to the benefit of ratepayers and the Utilities.

- **Innovation**: FortisBC is proposing a fund aimed at research and development and demonstration of the viability of new technologies to provide customers with clean and affordable energy sources for the future.

Table B3-1 outlines how these key features align with the identified themes for the rate plan.

Table B3-1: Features of the 2020-2024 Rate Plans

Feature	Proposal	Theme Alignment
Term	2020-2024 (5 Years)	Multi-year rate plan
O&M	O&M/Customer escalated by Inflation	Stable levels of O&M funding Incentive to invest in our future
Capital	Forecast except FEI Growth capital which is unit cost based	Incentive to invest in our future, Responsive to intervener feedback
Incentives	Combination of traditional and targeted incentives	Incentive to invest in our future
Innovation	Innovation funding	Flexibility to innovate and adapt, Incentive to invest in our future

3.7 CONCLUSION

FortisBC's rate plan must evolve in response to changes in the operating environment, our experience with the current rate plan, and stakeholder feedback. Specifically, at this time, a multi-year rate plan framework that provides stable levels of O&M funding, the flexibility to innovate and adapt, and incentive to invest in our future is needed for the ongoing health of the Utilities. FortisBC believes that its proposed framework will achieve the benefits of incentive-based ratemaking discussed in Section B2.6, including:

- promoting a continuous efficiency focus;
- aligning the Utilities' and ratepayers' interests and/or encouraging the Utilities to achieve targeted outcomes, while ensuring service quality requirements are met; and
- creating an efficient regulatory process for the period of the Proposed MRP, allowing the Utilities to focus on effectively managing business priorities, increasing innovative solutions to utility challenges and minimizing costs for customers.

Section C of this Application discusses the details of FortisBC's Proposed MRP framework that are designed to achieve these benefits.

FortisBC Energy Inc. and FortisBC Inc.

Application for Approval of a Multi-Year Rate Plan for 2020 through 2024

Section C:

PROPOSED RATE PLAN

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C: PROPOSED RATE PLAN

Introduction and Guiding Principles

FortisBC's proposes MRPs that will determine natural gas delivery rates and electricity rates over the 2020-2024 period for FEI and FBC, respectively, reflecting the costs necessary to build, maintain, finance and operate the infrastructure necessary to provide service to customers. FortisBC has designed its proposed 2020-2024 MRPs to build on the successes of the Current PBR Plans, while responding to the challenges experienced, stakeholder feedback received, and key changes in the operating environment as described in Part B of the Application.

The Proposed MRPs were also guided by the five Rate Plan Principles outlined below. These five principles are consistent with the common themes in the principles used in most jurisdictions, although they are articulated in many different ways.[102] In no particular order, the guiding principles, and the elements of FortisBC's Proposed MRPs that correspond to the principles, are shown in the following table.

Rate Plan Principles	Elements of Proposed Multi Year Rate Plan
Principle 1: The MRP should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the MRP.	In its efforts to develop MRPs that recognizes the interests and issues of concern of interveners, FortisBC solicited input from interveners and where appropriate, incorporated changes to address intervener feedback provided. Enhancements include: • Non-formula approach for determining capital funding; • Base O&M funding is index based; • Regulatory framework focused on the Companies' growth and performance in a challenging operating environment; and • Innovative technology funding. Further, the proposed earning sharing mechanism will ensure that the interests of ratepayers and Utilities are aligned throughout the Proposed MRP term.
Principle 2: The MRP must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.	In accordance with the BCUC's determination in the 2014-2019 PBR Plan Decision, the rate plan has been designed to "achieve a proper balance of risks and rewards between the Companies and the ratepayer and reflect current reality"[103]. FortisBC's rate plans include incentive to maximize the efficiency of capital and O&M spending through: • A unit cost approach to O&M and FEI Growth capital spending, and • A 5-year capital forecast for FBC Growth and FEI/FBC sustainment and Other capital spending.

[102] For example, these principles are expressed by the Alberta Utilities Commission (AUC). Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

[103] Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018. September 15, 2014. Page 16.

Rate Plan Principles	Elements of Proposed Multi Year Rate Plan
Principle 3: The MRP should recognize the unique circumstances of FortisBC that are relevant to the MRP design.	The Proposed MRPs are designed to provide FortisBC the flexibility and incentive to address challenges and pursue opportunities presented by changes in its operating environment including: • shifting climate policies focused on reducing GHG emissions; • changing customer expectations; • an increasing need to engage stakeholders and Indigenous communities; • aging infrastructure; • increased security requirements; and • the need for innovation and adoption of new technologies. FortisBC has incorporated features such as its Innovation Fund and Targeted Incentives for achievement and performance in emerging and strategic areas.
Principle 4: The MRP should maintain the utility's focus on maintaining, safe, reliable service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.	The term of the Proposed MRPs promotes regulatory efficiency, increased utility focus on managing with a longer-term view, and increased operational flexibility to address energy industry transformation. FortisBC proposes a suite of SQIs for FEI and FBC that will monitor each utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality. The Traditional Incentives embedded within the Proposed MRPs provide continued focus on efficient operations.
Principle 5: The MRP should be easy to understand, implement and administer and should reduce the regulatory burden over time.	The Proposed MRPs build on the success of the Current PBR Plans, continuing with many of the same features that are well understood. The current Annual Review process will be continued providing an efficient forum and opportunity for the BCUC, interveners and interested parties an opportunity to review the Companies' performance.

The material in Section C of this Application, along with the information contained in the referenced Appendices, provides a comprehensive description of FEI's and FBC's Proposed MRPs:

Section C1 – Components of Proposed Rate Plan – sets out the various components of the rate plan and provides a summary of each. Further details on significant components are provided in Sections C2 through C8.

Section C2 – O&M Base and Formula – describes the proposed 2019 Base O&M and discusses how O&M funding will be determined during the term of the Proposed MRPs.

Section C3 – Capital Forecast – discusses FEI's 2019 Base Growth capital and funding over the Proposed MRP term, and provides FEI's and FBC's forecasts of all other capital expenditures over the Proposed MRP term, and an update on anticipated Major Projects.

Section C4 – Annual Calculation of the Revenue Requirement – discusses the items that will be included in the revenue requirement at each Annual Review, and the proposed treatment of variances from forecast for each item.

Section C5 – Deferral Accounts - discusses FEI and FBC's proposed new deferral accounts and changes to existing deferral accounts.

Section C6 – Innovation Funding – describes FortisBC's proposed new funding to accelerate investment in innovative technologies.

Section C7 – Service Quality Indicators – describes FEI and FBC's proposed suite of SQIs to monitor performance during the Proposed MRPs.

Section C8 – Incentives – describes the incentives in the Proposed MRPs, including Traditional incentives through ROE sharing and Targeted performance incentives focused on addressing some of the challenges in FortisBC's operating environment.

Section C9 - Proposed Rate Plan Summary of Changes and Rate Projection - summarizes the Companies' proposals and indicative 2020 rates incorporating all of the proposals, including those set out in Section D.

1. COMPONENTS OF THE PROPOSED RATE PLAN

1.1 *INTRODUCTION*

This section describes the components of the proposed 2020-2024 MRPs for FEI and FBC. Table C1-1 below summarizes the terms of FortisBC's MRP proposals, and references the section where the details can be found. Most elements of the proposed plan are identical for the two Companies.

Table C1-1: Summary of 2020-2024 MRP Proposals

Item	2020-2024 MRP Application	Section(s)
Term	A five-year term from 2020 – 2024 is proposed.	C1.2
Inflation Index (I-Factor)	A weighted average of AWE:BC for labour costs and CPI:BC for other costs will be used to determine the I-Index, which will be calculated annually.	C1.3
Controllable Expenses - O&M	An inflation-indexed unit cost approach for O&M is proposed. A base of 2019 O&M per customer is adjusted for inflation and multiplied by a forecast of customers. O&M will not be rebased during the Proposed MRP term but will be subject to true-up for actual customers.	C2
Controllable Expenses - Capital	***FEI***: A unit cost approach is proposed for FEI's growth capital; other regular capital will be undertaken according to a five-year capital forecast. The growth capital formula is tied to forecast gross customer additions and the unit cost is inflation-indexed. Growth capital will not be rebased during the Proposed MRP term but will be subject to true-up for actual gross customer additions. ***FBC:*** Regular capital expenditures will be undertaken according to a five-year capital forecast.	C3
Growth Factor	Customer growth forecast annually with true-up for actual in the following year(s).	C1.4
Forecast O&M and Capital	Certain O&M and capital items do not fit well within formula because, for example, they are tied to parts of the business that are changing in response to government policy. These costs will be forecast each year in the Annual Review and variances will be captured in the Flow-through deferral account.	C2 and 3
Forecast Revenues and Margins	Revenues are forecast each year for rate setting purposes. The Companies will continue to flow variances in revenue through the Flow-through deferral account. FBC will continue to flow variances in power supply costs through the Flow-through deferral account.	C4
Non-Controllable Expenses	Certain O&M and capital expenditures, and interest and tax rates outside the control of the Companies will be forecast on an annual basis. Variances will be flowed through in rates.	C4
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and BCUC decisions will be flowed through in rates, subject to BCUC approval.	C4
Innovation Fund	FortisBC is proposing a fund aimed at research and development and demonstration of the viability of new technologies. The funding proposal recognizes the need to accelerate investment in innovation in order to provide customers with clean and cost-effective energy	C6

Item	2020-2024 MRP Application	Section(s)
	sources for the future. This fund will help the utilities gain the flexibility to innovate and adapt to the changing environment.	
Service Quality Indicators	***FEI***: 13 SQIs (9 SQIs with a target benchmark and 4 informational measures) are proposed that deal with customer service, employee safety and reliability. ***FBC***: 12 SQIs (8 SQIs with a target benchmark and 4 informational measures) are proposed that deal with customer service, employee safety, and reliability.	C7
Earnings Sharing Mechanism	The Companies are proposing a 50:50 earnings sharing mechanism between customers and the Companies for earnings above and below the allowed ROE.	C8
Targeted Incentives	An annual financial incentive in the form of additional basis points added to the Companies' allowed ROE, based on the Companies' level of success in attaining the overall composite scorecard target.	C8
Efficiency Carryover Mechanism	FortisBC proposes an ECM in the form of an add-on to the approved ROE for two years after the end of the Plans' term. The ROE add-on is equal to one half of the difference between the average achieved and authorized ROE, to a maximum of 50 basis points, over the last two years of the Plan (providing the difference is positive).	C1.5
Off Ramps	A review of the Proposed MRPs may be triggered by either a 200 basis point ROE variance (post-sharing) above or below the allowed ROE, or a 150 basis point ROE variance for two consecutive years.	C1.6
Annual Review	Annual reviews are proposed for this MRP.	C1.7

1.2 *TERM*

FortisBC proposes a five-year term for the MRPs, for the years 2020 to 2024. Five years remains a commonly adopted term for MRPs in North America, and is one year shorter than the six-year term of the Current PBR Plans, which were extended beyond the proposed five-year term because of the timing of the regulatory proceeding and decision "in order to realize the full benefits of a five-year term".[104]

A five-year term addresses the key objective of regulatory efficiency as the term minimizes the frequency of comprehensive RRAs. A five-year period also provides an adequate amount of time for the Utilities to plan and undertake priority work and achieve efficiencies related to the longer-term planning horizon.

In FortisBC's view, the generally positive experience of the Current PBR Plans support a five-year term for the 2020-2024 MRP. Proposed checks and balances implicit in the Proposed MRPs, discussed below, will mitigate risk to customers and the Utilities in the context of a five-year term. Moreover, the Annual Review of the Companies' performance promotes regulatory transparency. The achieved efficiencies, service quality measure results, earnings sharing

[104] Order G-138-14, page 27.

results, and the off-ramp mechanism (if necessary) all provide regular opportunities during the term to assess the success of the Proposed MRP.

1.3 *INFLATION FACTOR (I-FACTOR)*

The use of an inflation or I-factor in an MRP provides recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. As in the Current PBR Plans, FortisBC proposes to continue the use of a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to Statistics Canada's AWE:BC and non-labour indexed to the All-items Index for CPI:BC[105].

Using the composite factor weighting of 55 percent for labour and 45 percent for non-labour expenses, the I-Factor determination for the Proposed MRP remains:

$$I_t = 55\% \ x \ AWE\!:\!BC_{t-1} + 45\% \ x \ CPI\!:\!BC_{t-1}$$

Where: *I = Inflation Factor*
AWE:BC = labour index
CPI:BC = non-labour index
t-1 = most recent July to June values

As part of the Annual Reviews, FortisBC will update both the AWE:BC and CPI:BC rates as shown in the formula above to determine the value of the I-Factor for the years 2020 through 2024.

1.4 *GROWTH FACTOR*

Under the proposed unit cost approach to O&M, FortisBC proposes to maintain the average number of customers[106] as the growth factor. For the proposed FEI Growth capital formula, FEI proposes to adopt gross customer additions (instead of service line additions) as the growth factor.[107]

For both the index-based O&M discussed in Section C2 and the unit cost approach to FEI's Growth capital discussed in Section C3.3.1, FortisBC is proposing to eliminate the two adjustments to the growth factor that were imposed under BCUC Orders G-138-14 and G-139-14. These two adjustments were:

1. a reduction in the growth factor by one half; and

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[105] In Orders G-164-14 for FEI and G-182-14 for FBC the BCUC also approved the use of Statistics Canada CANSIM Table 326-0020 (now 18-10-0004-01) to determine the CPI:BC and CANSIM Table 281-0063 (now 14-10-0223-01) to determine AWE:BC.

[106] Calculated as the twelve-month average of the forecasted number of customers.

[107] The reasons for this change are discussed in Section C3.3.1.2.1.

2. the use of lagged actual customer growth.

The rationale for discontinuing these two adjustments is discussed below.

1.4.1 Use of Forecast Growth Factor

Forecast Growth Factor is Most Appropriate

FortisBC explained the reasons why a forecast growth factor is preferable to a lagged actual growth factor in its reconsideration of the 2014 PBR Decisions,[108] as follows:

1. Costs and revenues are both driven by the actual growth experienced in the year for which rates are being set. FortisBC's proposal to use forecasts of customer growth for demand and revenues aligns with using this same driver for costs. With the BCUC approved method, customer demand and revenues are calculated based on forecast growth in the customer base, but the costs lag behind forecast growth because they are determined using less current data.
2. The BCUC's decision was premised on the concern about forecasting bias. However, the approved lagging approach replaced the potential for forecast error with an approach that was known to introduce regulatory lag.
3. The use of forecast growth factor is consistent with (1) the approach under traditional cost of service ratemaking, (2) the approved approach in other PBR plans, and (3) how FortisBC internally forecasts its costs.

In the Reconsideration Decision, the BCUC approved the recovery of the variance in earned return related to the use of lagged rather than actual customer growth, but did not approve the use of forecast growth factors in the PBR formulas. However, the BCUC recognized the problem inherent in using a lagged actual growth factor in its Decision accompanying Order G-15-15 in the PBR reconsideration proceeding (PBR Reconsideration Decision), where it stated:

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

Although this PBR Reconsideration Decision was helpful in ensuring that FortisBC was not harmed in terms of earnings in relation to the lagging nature of the growth factor, it did not address the issue that the approved formulas themselves were never adjusted for this timing issue. During the Current PBR Plans' term, when customer additions were increasing, this caused an issue in the funding envelope, particularly for Growth capital, as the amount of allowed spending was not escalating at the same rate as the volume of actual spending was.

[108] FEI-FBC Application for Reconsideration and Variance of Order G-138-14 and G-139-14 - Phase 2 Reconsideration Application submission of FEI and FBC, pages 3 through 13.

The following table compares FEI's approved Growth capital with Growth capital recalculated using actual additions.

Table C1-2: FEI's Approved Growth Capital vs. Growth Capital Using Actual Additions

Growth Capital $000	2014	2015	2016	2017	2018	Total
Approved Growth Capital using lagging growth	21,809	28,480	33,263	33,477	37,485	154,514
Growth Capital recalculated using Actual Additions	30,508	34,172	34,136	44,028	46,376	189,221
Difference	(8,700)	(5,692)	(873)	(10,551)	(8,891)	(34,708)

The above table demonstrates that funding for FEI's Growth capital using a lagging growth factor underfunded the capital requirements by approximately $35 million to the end of 2018[109]. By using the lagging growth factor, the Growth capital formula provided too few dollars. By using a forecast of gross customer additions, the Growth capital provided by formula will be more closely matched to the funds required to connect customers.

True-Up Mechanism Will Address Forecast Errors

FortisBC is proposing a mechanism to true-up the Companies' O&M expenditures and FEI's Growth capital expenditures and rate base for the actual growth factors. A forecast of growth factors is used to determine the Companies' O&M and FEI's Growth capital required for the rate setting year. As discussed, using a forecast ensures the Companies have the necessary funds to connect customers and operate the business in the year the funds are required to be spent. However, FortisBC recognizes that by using forecast, a forecast error will result in either an under recovery or over recovery of costs. FortisBC's proposed true-up mechanism will adjust the Companies' O&M expenditures and FEI's Growth capital for the forecast error. The adjustment will be determined in each Annual Review and be included as an adjustment to the formula amounts. By including the true-up as an adjustment to Growth capital, rate base is consequently also adjusted so that forecast error is eliminated and does not persist.

The true-up adjustment will ultimately carry over for two years past the final year of the Proposed MRP term into the two subsequent Annual Review (or Revenue Requirement) applications so that the forecast errors are completely eliminated and that both customers and the Companies are held whole for forecast variances.

1.4.2 Elimination of 50 Percent Factor

In the 2014 PBR Decisions, the growth factor was reduced by one-half (50 percent). The Panel established the 0.5 multiplier to adjust the growth factors for the "assumed" non-linear correlation between growth-related expenses and the proposed growth factors. The 50 percent reduction was not based on any particular analysis but rather set based on the best judgement of the Panel at the time, which noted that "(*i)f Fortis has evidence that a different growth term is*

109 FEI has omitted 2019 as actual additions are not yet known.

more appropriate, it can bring forward that evidence at any time". For the reasons explained below, FortisBC is proposing in this Application to discontinue the 50 percent reduction factor.

<u>There is a high correlation between growth factors and expenditures</u>

A correlation coefficient is a measure of the strength of the linear relationship between two variables and can be used to analyze the strength of linear relationship between the growth factor and actual expenditures. As explained in Section B2.3.2.1.1, the correlation coefficient between FEI's number of new attachments and actual formula-related growth capital costs is close to 0.95. Similarly, the correlation coefficients between the average number of customers and actual formula O&M expenditures for FEI and FBC are calculated at 0.95 and 0.90 respectively. These high correlation coefficient numbers indicate a strong linear relationship between the variables and negate the need for the 0.5 multiplier.

<u>The anecdotal evidence goes both ways</u>

To support its assumption of non-linearity between growth factors and growth-related expenses, the Panel's 2014 PBR Decision provided isolated examples of instances when costs do not increase linearly but rather only increase when a threshold in growth is reached. The anecdotal evidence, however, goes both ways.

That is, while it is possible to find examples of cost items that do not increase linearly, the anecdotal evidence also supports a need for an increase to the growth factor. An example is the costs attributed to the attachment of industrial customers. The O&M and capital funding required for attachment and servicing of one new industrial customer can be many times more than what the formula growth factor provides. This is because the formulas are indexed to the average costs of all customer (the majority of whom are residential), while the average cost of attaching and servicing a new industrial customer can be significantly higher than the average costs embedded in the formulas.

<u>The 50 percent reduction to the growth factors is one of the reasons for persistent underfunding of formula capital amounts</u>

In the Current PBR Plans, the following year's formulaic Growth capital built upon the prior year's Growth capital envelope. As a result, the lagging growth factor along with the 50 percent reduction created a persistent and cumulative reduction to the Companies' Growth capital funding required to connect customers. For instance, FEI's Annual Review for 2015 Delivery Rates states:

> Actual customer growth experienced in 2014 was 1.2 percent, but the formula for growth capital, which utilizes one-half of prior year customer additions, only provided for customer growth of 0.26 percent.
>
> The challenge FEI faced in 2014 in meeting its growth capital formula is expected to continue through the remainder of the PBR Plan.

FEI's Annual Review for 2016 Delivery Rates again identified the growth factor embedded in Growth capital as a detriment to constraining spending to the formulaic funding levels. FEI stated:

> Growth capital is projected to be above the formula by $9.733 million as the formula for growth capital, which utilizes one-half of prior year service line additions, does not adequately fund the increase in capital required to support customer additions.

Further, in FEI's Annual Review for 2017, 2018 and 2019 Delivery Rates FEI noted that the 50 percent reduction in the growth factor along with the lag in timing of when customer growth is reflected in the formula as compared to when customers are actually added causes pressure on the formula in years of higher customer growth.

The elimination of the 50 percent adjustment factor, coupled with the true-up mechanism described above, will keep customers whole and help reduce capital variances. Therefore, FortisBC submits that the 50 percent adjustment factor should not be incorporated in the Proposed MRP.

1.4.3 FortisBC's Proposal for the Growth Factor

In summary, FortisBC is proposing to use a forecast of 100 percent growth factor, which is the same method that was approved during FEI's 2004-2009 PBR term. For O&M, this is a forecast of the overall number of customers[110] and for FEI's Growth capital, this is a forecast of the number of gross customer additions. Recognizing, however, the concerns of the BCUC and interveners that were raised during the 2014 PBR proceeding, FortisBC proposes to true-up its forecast of growth factors to actual, once known, to eliminate the impact of any perceived forecasting bias as was referred to in the 2014 PBR Decisions[111]. The proposed approach addresses any concern regarding forecast bias because it does not simply adjust the prior year's driver (customer growth) in the following years, but adjusts the calculation of O&M and Growth capital in the test year for the previous years' forecast error. The true-up, therefore, returns to or recovers from customers any difference between forecast and actual customer growth.

FortisBC's proposal to use the forecasted number of customers for O&M, or the forecasted gross customer additions for FEI's Growth capital, and then true-up the forecast spending envelopes for the actual growth in following years addresses the concerns raised in the 2014 PBR proceeding as well as some of the challenges experienced with the formula approved for the Current PBR Plans' term.

110 Twelve month average.
111 Order G-138-14, page 122, Order G-139-14, page 119.

1.5 *EFFICIENCY CARRY-OVER MECHANISM*

FortisBC is proposing an ECM to strengthen the incentive properties of the Proposed MRPs. The logic supporting ECMs generally and FortisBC's proposed ECM model specifically are explained below.

1.5.1 Purpose and Rationale for ECMs

Under multi-year rate plans the utility's incentives to pursue efficiency gains declines over the plan's term. This is because the reward for a utility is greatest when the efficiency savings are made in the first year of the plan. As the plan's term gets closer to its end, the amount of time remaining to achieve a return on efficiency investments becomes successively shorter, reducing the incentive properties of the plan. In other words, the incentive properties of multi-year rate plans are time-dependent and there is an incentive imbalance between earlier and later plan years.

The purpose of an ECM is to mitigate the timing issue that makes the incentives time-independent, by incenting utilities to pursue efficiency initiatives throughout the entire plan period. An ECM can do this by allowing the utility to keep a share of performance gains for a set period of time after a rate plan is concluded. The AUC's 2018-2022 PBR decision summarizes the logic and function of an ECM function as follows[112]:

> A utility's incentive to find efficiencies weakens as the end of the PBR term approaches, in part because there is less time remaining for the utility to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the utility to continue to benefit from any efficiency gains after the end of the PBR term. As Brattle noted, an ECM strengthens incentives to control costs towards the end of the PBR term by "carrying over" some of the rewards from successful cost control from one PBR term to the next one. The Commission approved an ECM in Decision 2012-237 to encourage distribution utilities to continue to make cost-saving investments near the end of the PBR term and discourage gaming regarding the timing of capital projects or programs.

1.5.2 ECM Examples in Canada

ECM is not a new feature to multi-year ratemaking plans and various forms of ECM have been approved by regulators in a number of jurisdictions[113]. Alberta's ECM approach is probably the most well-known ECM example currently in place in Canada. As explained in Appendix C4-2, Alberta's first generation performance-based ratemaking plan included a simple ECM approach that allowed for an add-on to the approved ROE equal to one half of the difference between the

[112] AUC decision 20414-D01-2016; pp 18-19.

[113] In addition to Alberta, Ontario and BC's ECM model discussed in this section, Regie in Quebec has also adopted ECM in specific cases. Outside Canada, regulators in Australia and U.S. have also adopted ECMs as part of their overall MRP package.

simple average ROE achieved over the term of the plan and the simple average approved ROE over the same period (providing the difference is positive), to a maximum of 0.5 percent, for two years after the end of the plan. The AUC's second-generation PBR plans continue to adopt the same ECM model.

Under the OEB's consolidation guidelines, consolidating electric utilities are allowed to select a maximum rebasing deferral period of ten years (five years for the recent case of the Union Gas and Enbridge Gas Distribution amalgamation) with no supporting evidence required to justify the selected deferral period. The deferred rebasing functions similar to an ECM in the sense that the utility can carry-over the benefits of the achieved savings for the duration of the deferred rebasing period.

Further, and as stated in Appendix C1, FEI's 1998 plan included a capital efficiency mechanism where the variance between allowed and achieved capital expenditures was added to the rate base and phased-out over three years. FEI's 2004 plan also included a similar approach and allowed the accumulated capital carrying cost and depreciation benefits to continue for two years following the end of the plan's term.

1.5.3 FortisBC Proposed ECM

FortisBC is proposing to implement an ECM model similar to the one established in Alberta with some minor changes. Under FortisBC's proposed model one half of the difference between the simple average ROE realized over the last two years of the Proposed MRPs[114] and the simple average authorized ROE over the same period is added to the approved ROE for two years after the end of the Proposed MRPs (providing the difference is positive). This ROE adder would be capped at 50 basis points and will be applied to the mid-year rate base of the final year of the Proposed MRPs.

As explained in Section B2.3.1.1, the evaluation of the Companies' performance in the Current PBR Plans indicate that annual savings above the formula level peaked in the third year of the plans. The proposed approach to consider the performance in the last two years of the Proposed MRPs is based on this observation. Therefore, the proposed approach to only consider the last two years of the Proposed MRPs (as opposed to the entire term) will improve the balance of incentives between the earlier and later plan years.

1.6 *OFF-RAMP PROVISION*

Earnings-based trigger mechanisms, which are triggered if the actual ROE of the utility differs significantly from its approved ROE, are the most common form of off-ramp provisions. The Companies propose to retain the financial off-ramp provisions as determined for the Current PBR Plans whereby an off-ramp is triggered if earnings in any one year varies from the approved ROE by more than +/- 200 basis points (post sharing) or if earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years.

[114] The realized ROE would be after sharing but before targeted incentives.

1.7 ANNUAL REVIEW PROCESS

The Current PBR Plans include an Annual Review which provides the BCUC, interveners and interested parties with an opportunity to review the Companies' performance during the prior year. In the Annual Reviews, FortisBC files its forecast revenue and costs outside of formula amounts, and the BCUC determines the rates for the upcoming year. The current Annual Reviews have been a successful tool in communicating the Companies' performance and activities, and also for understanding the issues and challenges facing the Companies.

Based on the effectiveness of the past Annual Reviews, FortisBC proposes to continue the Annual Review process for the Proposed MRPs. Each year, the Annual Review will present the current year's projections and the upcoming year's forecasts for a number of key measures, including:

- Customer growth, volumes and revenues;
- Year-end and average customers, and other cost driver information including inflation;
- Expenses, determined by the indexing formula plus items forecast annually;
- Capital expenditures (as provided for by the capital forecast with FEI's Growth capital determined by the indexing formula), plus other items forecast annually;
- Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
- Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year;
- Service Quality Indicator results;
- Targeted incentive results; and
- Reporting on the Innovation Funding status.

Consistent with the Current PBR Plans' term, FortisBC expects that the Annual Review regulatory process under the Proposed MRPs will generally include a workshop, one round of IRs from the BCUC and Interveners, submissions and a BCUC determination of rates.

2. O&M BASE AND FORMULA

2.1 INTRODUCTION TO O&M

During the Proposed MRPs, the amount to be included in rates for the bulk of FortisBC's O&M expenses will be determined using an O&M per customer amount escalated by inflation. The starting point for determining the O&M per customer amount is the 2019 Base O&M, which is the adjusted actual O&M expenditures for 2018 expressed over the average number of customers for 2018, escalated by the approved formula inflation factors for 2019. FortisBC's 2018 O&M expenditures per customer is an appropriate starting point as it incorporates the productivity savings achieved over the Current PBR Plans, and also reflects the current costs necessary to meet safety standards and other service requirements. As part of the 2019 Base O&M, FEI and FBC are proposing incremental funding to support initiatives that address future key issues and challenges in the operating environment.

Similar to the Current PBR Plans, for the Proposed MRPs FortisBC will set the component of rates designed to recover O&M expenses by adjusting the previous year's calculated amount for customer growth and inflation. This adjusted amount is designed to provide O&M funding for the Companies to maintain their high overall service quality levels and address the challenges in their operating environment including changes in regulations, compliance requirements, customer expectations, growing customer base, and climate policy.

2.2 2019 BASE O&M INCORPORATES SAVINGS FROM CURRENT PBR

FEI's and FBC's proposed 2019 Base O&M requirements for the Proposed MRPs are reasonable and necessary. Both FEI's and FBC's proposed 2019 Base O&M are lower than the O&M levels prior to the start of the Current PBR Plans[115], due to permanent savings from the Current PBR Plans being embedded in the O&M levels going forward.

As outlined in Section B2.3.1, FortisBC has been a responsible steward in prioritizing and managing its overall O&M expenditures during the period of the Current PBR Plans. On an O&M per customer basis, spending has trended downwards for both FEI and FBC during the term of the Current PBR Plans while service quality levels were maintained. FEI and FBC will continue to be responsible stewards of their O&M expenditures during the Proposed MRP period.

115 FEI: On an inflation adjusted basis, 2019 Total O&M per customer of $285, 2019 Formula Base O&M per customer of $250 compared to 2013 Total O&M per customer of $314, 2013 Actual Formula O&M per customer of $286.
FBC: On an inflation adjusted basis, 2019 Total O&M per customer of $439, 2019 Formula Base O&M per customer of $416 compared to 2013 Total O&M per customer of $495, 2013 Actual Formula O&M per customer of $457.

A broad-based productivity focus contributed to the Companies' ability to contain O&M costs over the Current PBR Plans. Productivity was not focused solely on "cost cutting" but was also focused on "doing more with the same". Examples of this approach include:

- <u>Growing the Customer Base:</u> FEI has been successful in growing its customer base, having reached its one million natural gas customer milestone in 2017. FEI has been successful in adding more customers without a corresponding increase in Energy Solutions staffing levels. At the start of the Current PBR term, there were 250 new customers added to the natural gas distribution system for every one Energy Solutions employee. In 2018, the Energy Solutions team was able to support adding approximately 425 new natural gas customers for every one Energy Solutions staff member.
- <u>Recruiting Employees:</u> FortisBC has been successful in recruiting employees to meet the Companies' needs while maintaining its Human Resources department's staffing level. Since 2016, overall staffing levels at FortisBC have increased (FEI – 9 percent and FBC – 5 percent) contributing to a steady increase in recruitment activities. Additionally, the labour market has become more complex with low unemployment rates, skill shortages and higher retirement rates. With an increasingly competitive talent market, finding and retaining employees is projected to be the most difficult task facing human resources departments. FortisBC's Human Resources department has been able to meet the Companies' recruitment needs in this challenging labour market without additional resources.
- <u>Operations:</u> BC One Call ticket volume has increased by 70 percent since 2013 with an incremental resource increase of only 13 percent (2 headcount), while physical locates have decreased by three percent, demonstrating the efficiencies implemented in the Public Underground Location Services department at FEI. Doing more with the same is apparent in the reduction in physical locates required while the volume of tickets responded to has increased. Additionally, the quality of information has improved, contributing to fewer instances where a technician has to attend on site. The cost to respond on a per-ticket basis has also decreased since 2013 from $12.44 to $12.10 which has helped offset some of the costs of the growing ticket volumes.
- Another example of increased productivity are for Operations and Engineering administrative support resources related to new construction, preventative maintenance, and corrective work activities. In addition to the consistently high volume of new customer attachments, the Operations and Engineering department has seen a steady increase in the volume of both preventative and corrective work, with no corresponding increase in administrative resources required.

FortisBC will maintain this discipline and rigour in its approach to managing O&M expenditures in the Proposed MRPs, where we expect to face both continued and new cost pressures.

2.3 *2019 BASE O&M WILL REQUIRE FORTISBC TO DO "MORE WITH THE SAME"*

As highlighted in recent Annual Reviews, finding new productivity opportunities is increasingly difficult, as the Companies have achieved efficiencies after a number of years of successfully implementing cost savings that have been shared with customers. To manage the expected cost pressure challenges during the Proposed MRPs, FortisBC will be relying more on a productivity focus of "doing more with the same".

FortisBC believes this approach to productivity represents an appropriate balance between the ongoing need to manage costs and mitigate customer rate pressure, while providing resources to support growth and the challenges being faced, while maintaining service levels during the upcoming MRP term.

Examples of cost pressures anticipated during the Proposed MRPs for which FortisBC is not requesting any incremental funding in the proposed Base O&M are:

- For FEI - Additional resources to enable continued investment in assets and customer service. Each year FEI is adding approximately 400 kilometers of new main and service pipe, 15,000 - 20,000 new services, pressure control stations, monitoring and controls. All of this capital requires resources to plan, install and commission the assets. The majority of capital related costs are charged directly to capital (i.e., quality assurance, construction crews, drafters, planners); however, some indirect costs (i.e., Operations Support Representatives (OSRs), capacity planning, management and other costs such as training activities) are included in O&M.
- For FEI - Additional employees in the Operations area are required to transition and provide for succession in the upcoming years due to retirements. The need for a successful transition is even more pronounced due to the recent period of high customer growth and associated higher employee base. This contributes to an increase in employee turnover as new positions filled create further openings and turnover within FEI. To support the employees that are new to FEI or new to their positions, an increase in requirements for learning and training is required. Key positions will be filled before employees leave to enable a smooth knowledge transfer.
- For FBC - Increased engineering and technology staffing to maintain the Supervisory Control and Data Acquisition (SCADA) system and the Outage Management System (OMS) and to maintain data for the Advanced Distribution Management System (ADMS), AMI, and Geographic Information System (GIS).
- For FEI and FBC - Increased general and administrative costs in areas like Human Resources, Finance and Procurement to support the growing needs of the business. The Finance department will require resources to support increased compliance requirements and continued changes in accounting standards as well as supporting audits. Additional Procurement staffing is required to support growing needs and capital

activities. Recruiting staff will be required to manage the increased level of recruitment activities.

- For FEI and FBC – Increased costs will be incurred in meeting evolving municipal regulations such as additional permitting, working arrangements, and restricted working hours.
- For FEI and FBC - Increased environmental and safety program requirements.

Additionally, FortisBC is already aware of a number of circumstances where actual inflation will be higher than the proposed inflation index, which will cause cost pressures that the Companies will need to manage by finding offsets. For example, costs to insure and operate vehicles, fees for rights of way, and facilities lease contract increases will be higher than what will be provided for by a CPI-based inflation factor. FortisBC will continue to look for productivity and cost savings opportunities to manage these cost pressures. An example of a productivity initiative is the Gas Workforce Management system, details of which are provided in Appendix B6 – FEI Report on Major Initiatives During the Current PBR Term.

Under the proposed approach to O&M funding, FortisBC will require the inflation and customer growth escalators in O&M to accommodate these and other similar increases in staffing and non-labour costs.

2.4 *FEI O&M BASE*

2.4.1 O&M Spending from 2013 to 2018

As discussed above and in Section B2.3.1, since the outset of the Current PBR Plan, FEI's O&M spending has trended favourably, both in total and on a per customer basis[116]. FEI's O&M per customer also compares favourably to other peer utilities. As shown in the FEI Benchmarking Study in Appendix C2-1 and discussed in Section B2.4.3, FEI's Distribution O&M and Total A&G per customer compares favourably to its peer utilities over the study period (2012 to 2017). FEI's results are near the Pacific Northwest U.S. company median and below the Canadian peer group median over the period of study. Also over the study period, FEI's Distribution O&M and Total A&G per customer costs increased modestly (nominal five-year compound annual grow rate of 0.16 percent), while the average costs for the peer groups increased more significantly.[117] These results confirm that FEI has been successful in realizing efficiencies and cost savings as a result of a broad-based productivity focus combined with a number of major initiatives.[118]

116 Figure B2-1 in Section B.2.2.1.1 O&M Expenditures.

117 Nominal Compound Annual Growth Rates 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 groups, respectively.

118 See Appendix B6 for a listing and discussion of the major initiatives.

2.4.2 Proposed 2019 O&M Base

FEI is using its 2018 actual expenditures as the starting point for the O&M Base as it is representative of FEI's current level of O&M funding required to operate its system safely and reliably, maintain its overall service quality level, and is reflective of the cost pressures that FEI has been managing in recent years. Examples of increasing cost pressures recently discussed in the Annual Reviews include cyber security, integrity digs, and growth and aging of the pipeline and distribution system. Additionally, 2018 actual expenditures reflect efficiencies and productivity improvements, as evidenced by FEI's ability to contain 2018 actual O&M below the formula O&M level, which includes the cumulative impact of the annual PIF of $38.0 million[119] approved as part of the Current PBR Plan.

Using the 2018 actual expenditures as the starting point for the O&M Base, adjustments are then made to arrive at the 2019 Base O&M. The adjustments are as follows:

- Add back temporary O&M net savings included in the 2018 actual expenditures and adjust for the effect of proposed shared and corporate services studies on O&M;
- Multiply by the 2019 formula inflator as approved in the Annual Review for 2019 Delivery Rates[120];
- Adjust for approved 2019 exogenous factors, items held in deferral accounts in the Current PBR Plan that are now included in Base O&M, and items currently in O&M that will be recorded in a deferral account in the Proposed MRPs; and
- Add new incremental funding required for the term of the Proposed MRPs.

The goal of these adjustments is to determine the appropriate starting point for O&M expenditures for the Proposed MRPs, incorporating known and measurable adjustments as appropriate.

Using the above method, the 2019 Base O&M is calculated as shown in the following table. Each adjustment is discussed below.

[119] Section B2.3, equal to total Current PBR term savings of $54.4 million less 2019 projected savings of $16.4 million.

[120] Financial Schedule 3, FEI's Compliance filing Orders G-237-18 and G-10-19 for Approval of Permanent Delivery Rates and Delivery Rate Riders, effective January 1, 2019.

1 **Table C2-1: FEI 2019 Base O&M ($ millions)[121]**

2018 actual Base O&M	$ 238.693
Add temporary savings	1.677
Corporate/Shared Services Studies Impact	(0.455)
Adjusted 2018 Base O&M	$ 239.915
2019 Inflator	1.02198
2019 Base O&M before adjustments	$ 245.188
Adjustments:	
Exogenous Factors:	
2019 Z factor (EHT net of MSP)	0.972
Deferrals:	
FAES overhead	0.786
BCUC levies	(2.778)
NGIF funding	(0.400)
Flow Through treatment:	
Integrity Digs	(2.600)
LNG Plant O&M	5.101
Total adjustments	1.081
New funding for MRP term	$ 10.416
2019 Base O&M	$ 256.685

2

3 On a per customer basis, the proposed 2019 Base O&M translates to $250 ($256.685 million
4 divided by 1,024,962 customers). To calculate the average number of customers, FEI has used
5 the 12-month average forecast for 2019.

6 ### *2.4.2.1 Temporary 2018 Net Savings*

7 Of the total net O&M savings above the formula achieved in 2018 of approximately $4.9 million,
8 $1.677 million, representing less than one percent of the overall O&M funding, were temporary
9 net savings that are not sustainable and that will require funding in during the term of the
10 Proposed MRPs.

11 The temporary savings consisted of approximately $0.770 million for meter reading and
12 approximately $0.900 million for bad debts.

[121] Corporate/Shared Service Impact is comprised of the 2019 amount of ($0.117) million for Corporate Services (Section D5) and ($0.338) million for Shared Services impact (Section D4).

2.4.2.1.1 METER READING

FEI has a contract with Olameter to provide meter reading services for gas customers. The contract requires FEI to pay for meter readings provided and includes penalties that Olameter is required to pay to FEI if it does not deliver on negotiated service levels.

In the last couple of years, Olameter has not met its contractual service levels to FEI due mostly to staffing and weather issues. In 2018, Olameter paid a penalty of $0.070 million based on 2017 performance. In addition, they were not able to complete all of the readings as set out in the contract, which resulted in FEI reducing payments to Olameter by approximately $0.700 million.

FEI considers these savings as not being sustainable, as we expect Olameter to meet their obligations under the contract in the future.

2.4.2.1.2 BAD DEBTS

Bad debt expense is difficult to forecast as it is affected by a number of factors including demand from customers which may be impacted by weather, changes in the price of the natural gas commodity, success of collection management practices, and general economic conditions which may impact the ability of customers to pay. In setting its bad debt funding required for a year, FEI considers and relies on actual historical bad debt expense to arrive at a reasonable forecast for bad debt expense.

In 2018, bad debt expense was very low relative to the previous five years. From 2014 to 2018, the average bad debt expense was approximately $1.8 million per year compared to the 2018 bad debt expense of $0.9 million. The $0.9 million of bad debt expense experienced in 2018 cannot reasonably considered to be representative of future bad debt expense. Contributing to the reduction in bad debt was the lower consumption due to the wamer weather experienced in 2018. Therefore, the lower bad debt spending in 2018 is considered temporary in nature with funding required in future years to be more reflective of historical levels of bad debt expense. In short, experience tells us that actual bad debt expense is typically higher than that observed in 2018.

2.4.2.2 Adjustments

2.4.2.2.1 EXOGENOUS FACTORS

FEI has one exogenous factor adjustment discussed below.

Employer Health Tax net of MRP

FEI was approved to adjust the 2019 O&M for the costs of the new Employer Health Tax (EHT) net of the Medical Services Plan (MSP) premiums reduction. The net increase of $0.972 million

($2.630 million EHT less the annual amount of ($1.658) million MSP premiums reduction)[122] has been adjusted in Table C2-1 above.

2.4.2.2.2 DEFERRALS

The three deferral items are discussed below.

FAES Overhead Recovery

As approved by BCUC Order G-138-14, the Thermal Energy Services Deferral Account (TESDA) Overhead Allocation Variance Deferral Account records the difference between the actual amounts for FEI support/overhead to FortisBC Alternative Energy Services Inc. (FAES) and the approved amounts, with any difference recovered from FEI customers in the following year. Included in the FAES overhead amount are direct costs for services provided and for support costs such as for facilities, telecommunications and information technology.

The approved overhead allocation for FAES support costs is currently approximately $0.9 million per year, an amount escalated annually according to the approved O&M formula. The approved amount was set at a time when the FAES business was evolving and maturing, and did not reflect the ongoing actual level of services provided to FAES. In addition to the annual formula amounts, Table C2-2 below provides the actual annual recoveries (services provided) since 2014, in the second line. As shown in the table, for each year of the Current PBR Plan, the O&M overhead recoveries for FEI that are embedded in the formula have exceeded the actual O&M overhead recoveries.

Table C2-2: FAES Overhead Recoveries

($ millions)	2014	2015	2016	2017	2018	2019 P
Budget O&M Overhead Recoveries	$ 0.870	$ 0.878	$ 0.887	$ 0.896	$ 0.907	$ 0.926
Actual O&M Overhead Recoveries	$ 0.635	$ 0.214	$ 0.160	$ 0.149	$ 0.137	$ 0.140
TESDA Overhead Allocation Deferral	$ 0.235	$ 0.663	$ 0.727	$ 0.746	$ 0.770	$ 0.786

Given the stable level of services provided to FAES and stable level of actual recoveries in recent years, there is no further need for the TESDA Overhead Allocation Variance Deferral Account. FEI, therefore, proposes to set the 2019 Base O&M to include an mount for the FAES overhead recoveries. As such, FEI's Base O&M needs to be adjusted to recognize the lower overhead recoveries, resulting in an increase in FEI Base O&M requirements of approximately $0.786 million, which is the difference between the recovery for services required and the amounts approved in rates.

[122] Order G-237-18 reflected the reduction of MSP premiums by 50 percent in 2019. MSP premiums will be eliminated as of January 1, 2020.

BCUC Levies

FEI has consistently had deferral account treatment for variances in BCUC levies. The deferral account recognizes that the funding required by the BCUC depends on a number of factors outside the control of FEI. Any difference between the approved and actual levies paid is captured in the deferral account and amortized in customer rates the following year. The O&M amount in the formula only reflects the 2013 Approved (Base) amount escalated by the formula.

BCUC levies have increased significantly over the Current PBR Plan term. In 2018, the BCUC actual levies were $5.267 million, compared to the approved amount of $2.778 million currently in the Base O&M[123], for a variance of $2.489 million added to the existing variance deferral account.

BCUC levies will continue to fluctuate outside of the control of FortisBC. As an example, while the BCUC levies for their fiscal 2019/20 have been set, the 2019 actual levies may vary.

For this Proposed MRP, because these levies are not controllable, FEI proposes to forecast the entirety of the BCUC levies outside of the formula instead of continuing the current treatment, which is to embed the current level in Base O&M subject to formula escalation. As a result, the $2.778 million that is currently in O&M will be removed from the Base O&M and BCUC levies will be forecast in each year's revenue requirements. FEI will record any difference between the forecast and actual levies paid in the BCUC Levies deferral account and amortize them in customer rates the following year.

Natural Gas Innovation Funding

FortisBC is proposing the creation of an Innovation Fund (discussed in Section C6) which, if approved, will fund future innovation initiatives, including FEI's contributions to the Natural Gas Innovation Fund (NGIF). FEI's 2018 O&M includes its current $0.400 million contribution to the NGIF. If FEI's Innovation Funding proposal is approved, then the amount currently provided by O&M will be removed.

2.4.2.2.3 FLOW-THROUGH TREATMENT

FEI is adding integrity digs as a category of costs afforded flow-through treatment, and is proposing a change to the amounts allocated between Base O&M and flow-through for its LNG operating costs.

Integrity Digs

FEI proposes to treat the costs of integrity digs, a critical element of the IMP, outside of the index-based O&M, as there is considerable uncertainty related to scope, cost, timing and volume of expected digs during the Proposed MRP term. The proposed flow through treatment of integrity dig costs during the Proposed MRPs relieves the constraints of index-based O&M on addressing pipeline safety issues and is appropriate based on the wide range of scope, costs,

[123] 2013 Approved escalated by the PBR formula to 2018 amounts.

timing and volume of integrity digs that may be experienced over the term of the Proposed MRPs.

For the period 2014 to 2019, expenditures for integrity digs have varied between a low of $2.3 million to a high of $3.2 million, with the costs incurred dependent on the required scope of work and the number of integrity digs.

Integrity digs are determined based on FEI's analysis of in-line inspection data (for piggable pipelines) or above-ground coating and cathodic protection survey data (for non-piggable pipelines) once they are completed. The results from these respective inspections determine the quantity, site-specific location, and timing of digs.

Table C2-3 below provides the number of integrity digs since 2011 showing an increasing trend in the number of digs. FEI is planning to complete approximately 100 digs in 2019 and this number is expected to continue to increase over the term of the Proposed MRPs as the number of kilometers of pipelines undergoing in-line inspection (ILI) increases and as the types of inspection tools and tool runs rise.

Table C2-3: FEI Integrity Digs 2011 to 2019

Reason for Digs	Number of Digs per Year								
	2011	2012	2013	2014	2015	2016	2017	2018 YEF	2019 Forecast
Dent digs (includes dig selections that were influenced by the strain-based criteria)	0	6	27	12	10	32	21	15	Under development (u/d)
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	27	20	11	44	39	u/d
Other ILI digs	45	24	21	19	32	33	25	36	u/d
Non-ILI digs	9	8	4	4	2	0	8	5	u/d
Total Integrity Digs	**54**	**36**	**52**	**62**	**64**	**76**	**98**	**95**	**≈ 105 +/- 10%**

It is challenging to predict the annual scope of this work and there is limited flexibility when scheduling the integrity digs. The scope of work required for integrity digs will have significant variation depending on location, surface and subsurface conditions, depth, proximity to geographic features (i.e., river crossings, environmental zones, and highways), season, and the number of imperfections requiring visual inspection. In addition, the actual work required to repair the imperfections is unknown until a physical inspection of the pipe is performed and an engineering assessment is complete. The cost of integrity digs will vary significantly and can range from $0.010 million (e.g., shorter-length excavation site, accessible to equipment, minimal permits and environmental impacts, minimal site restoration costs) to $0.150 million (e.g., dig below a remote stream location). The timing and volume of required digs is influenced by multiple factors including the number of imperfections requiring inspection/repair, and the kilometers of ILI run. Notably, when performing ILI in a pipeline for the first time, or when running a new ILI technology for the first time, the prediction of the quantity, site-specific location, and timing of digs is highly uncertain.

A related consideration is the impact of the IGU project. The IGU project is expected to result in an increase in the number and associated costs of integrity digs starting in 2022. This is because integrity digs are an integral component of the ILI process and, as the number of kilometres of pipelines inspected through ILI increases, so does the number of required integrity digs. In addition, the pipelines being added through the IGU project are being inspected for the first time using ILI.

In FEI's 2014 PBR Decision, the BCUC stated that FEI should evaluate the impact of CPCNs on O&M, as follows:

> The Panel recommends that, if capital associated with a particular CPCN is excluded from the formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made[124].

Although the comments above were in reference to the Current PBR Plan, the rationale for the recommendation is equally applicable to the Proposed MRP. If the IGU project results in increases in O&M costs related to integrity digs, then the alternatives would be to either re-base the index-based O&M or flow the additional costs of the integrity digs outside of the Base O&M. To provide greater transparency, FEI believes the preferred alternative is to flow all of the integrity dig costs outside of Base O&M.

Given the uncertainties associated with integrity digs, the importance of continuing to focus on this vital activity, the level of transparency gained, and the potential impacts of the IGU project, accounting for the integrity digs as a flow through provides an effective solution.

LNG O&M Costs

Allocation of LNG O&M Costs between Base O&M and Flow Through

LNG O&M costs, including labour, materials, contractors, electricity power and fuel, are necessary to operate the Tilbury and Mt. Hayes LNG facilities, as peaking storage facilities and in support of sales of LNG to customers. The Tilbury Expansion facility increases the LNG production capability at the site by approximately seven times the capability of the existing Tilbury plant.

During the Current PBR Plan term, FEI has recovered the total LNG O&M costs in two parts:

1. Costs related to providing peaking storage to service core utility customers were recovered as part of Base O&M; and

2. Costs related to providing Rate Schedule 46 service were forecast each year and flowed through to customers outside of the Base O&M.

[124] FEI 2014-2018 PBR Plan Decision, page 182.

This distinction was necessary primarily due to the unpredictable nature of the costs during a period of time when the Tilbury Expansion facility was under construction, and when the LNG for transportation service was undergoing a period of significant growth. As such, most of the costs at the time were variable in nature.

The Tilbury Expansion facility will be fully in service by the end of 2019, and the labour, materials and administration costs associated with running Tilbury as a combined operation will have stabilized by the start of the Proposed MRPs. Therefore, for the Proposed MRPs, FEI proposes to allocate LNG O&M costs based on whether they are fixed or variable costs, as follows:

- FEI will allocate to Base O&M the portion of the total O&M costs representing the fixed costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales). These costs are expected to be relatively stable over the term of the Proposed MRP.
- FEI will allocate the remaining portion of total O&M costs as a flow through outside the Base O&M. These costs represent the variable costs for the production of LNG (liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers with LNG, etc.) where the costs fluctuate and are dependent on sales volumes. Accounting for these costs as flow-through recognizes that these costs are dependent on sales volumes which are difficult to forecast and expected to increase over time.

This revised cost allocation approach will provide a clear and representative picture of the fixed costs to operate and maintain the LNG facility safely, regardless of the final use of the LNG, while providing transparency on the variable costs of production of LNG which are correlated with FEI's LNG sales volumes and revenues and peak shaving activities. The allocation also avoids FEI having to make a judgement-based determination of the amount of costs in support of Rate Schedule 46. This concern was highlighted in BCUC Order G-86-15 in FEI's Annual Review for 2015 Delivery Rates, where, due to difficulties in forecasting, the BCUC had recommended that FEI utilize an "embedded O&M rate" multiplied by the Rate Schedule 46 forecast volumes to forecast the LNG O&M outside of the formula.[125]

Table C2-4 below provides the total O&M expenditures incurred in 2018 related to both the pre-existing Tilbury and Mt. Hayes LNG facilities and the Tilbury Expansion facility.

[125] Order G-86-15 page 17.

Table C2-4: FEI Allocation of 2018 Expenditures for LNG Facilities

Description / Facility	2018 Actuals ($ millions)		
	Base	Flow Through	Total
Tilbury LNG Facility	$ 2.134	$ 6.401	$ 8.535
Mt Hayes LNG Facility	$ 2.767	$ 0.145	$ 2.913
Supporting Functions including management and engineering	$ 1.390	$ -	$ 1.390
Total	$ 6.291	$ 6.547	$ 12.838

Table C2-5 below provides the same LNG costs, but allocated between fixed (Base O&M) and variable (flow-through). The proposed cost allocation was determined based on a review of costs in recent years. As discussed above:

- Fixed costs are costs to operate the LNG plant, regardless of its use (i.e., for peak shaving storage, LNG production for sales). Fixed costs include operating and maintenance costs to ensure the safe and reliable operation of the facilities and the necessary management and administration required in order to remain compliant with regulations and permits.
- Variable costs are for the production of LNG (i.e., liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers to load LNG, etc.). Variable costs include employee and vehicles costs for truck loading and shunting activities, costs for liquefaction related materials, and shipping of production related wastes, contractor costs for shipping of materials, electricity charges and own use gas for the facilities.

Classifying the LNG production costs as variable and linking them to the LNG sales revenues is akin to a cost of goods sold approach to reporting, where the direct costs attributable to the production of the goods are matched to the revenues from the goods sold, consistent with accounting principles.

Table C2-5: FEI Proposed Allocation of 2018 Expenditures for LNG Facilities Reallocated

Description / Facility	Proposed Reallocation of 2018 Actuals ($ millions)		
	Base	Flow Through	Total
Tilbury LNG Facility	$ 5.449	$ 3.086	$ 8.535
Mt Hayes LNG Facility	$ 2.629	$ 0.284	$ 2.912
Supporting Functions including management and engineering	$ 1.391	$ -	$ 1.391
Total	$ 9.469	$ 3.370	$ 12.838

Under the proposed allocation approach, Base O&M will increase by approximately $3.177 million, with an offsetting decrease to future costs that are flowed through outside of Base O&M. Regardless of the allocation between Base and Flow-through, the total O&M costs to operate the LNG facilities will be the same; however, if the proposed reallocation was not made, the Flow-through component of the Tilbury LNG facilities O&M would continue to carry a fixed cost component.

Additional Funding Required for LNG Facilities

For the Proposed MRPs, FEI will require incremental Base O&M funding to operate and maintain the LNG facilities safely and in compliance with relevant regulations and permit requirements. The incremental funding required also reflects the increased plant size of the Tilbury expansion which is effectively seven times larger than the previous Tilbury base plant. More equipment and processes are required to operate and maintain the expanded Tilbury facility.

All LNG facilities within B.C, including the Tilbury and Mt. Hayes facilities, are required to meet the operating permit requirements specified by the BC OGC including the adoption of all aspects of the Canadian Standards Association (CSA) standard CSA-Z276, which is a technical standard developed and maintained by the CSA for the production, storage and handling of LNG. One of the core requirements of CSA-Z276 is to develop and maintain a safety and loss management program. The requirements of the safety and loss management program include components such as an equipment integrity management program, an emergency preparedness program, a security management program, a fugitive emissions management program and management of change program. In practice, the safety and loss management program incorporates rigor into all aspects of the operation, maintenance and management of each plant with the key focus being the safety of both the public and employees that work at the regulated facility.

In 2017, the BC OGC began the Compliance Assurance Process to support facility permit holders toward meeting the evolving standards for safety and loss programs within the oil and gas industry. This required facility permit holders to provide a self assessment of their respective safety and loss management program. In 2018, the BC OGC published the "Compliance Assurance Protocol - Integrity Management Program for Facilities" document, which outlines the required standard of performance for permit holders, and then began formally auditing the safety and loss management programs of facility holders across B.C. including FEI. As such, in order to maintain an effective safety and loss management program that is compliant with BC OGC requirements, while recognizing the increase in maintenance and operational activity with the start up of the Tilbury Expansion, FEI requires the following additional operational and technical resources.

Table C2-6 below lists the incremental amounts, totalling $1.853 million, with discussion provided below.

Table C2-6: Total Base O&M Funding Required to Operate and Maintain the LNG Facilities[126]

Description / Facility	Proposed Funding in Base O&M ($ millions)		
	Adjusted Base	Incremental	Proposed Base
Tilbury LNG Facility	$ 5.569	$ 1.201	$ 6.770
Mt Hayes LNG Facility	$ 2.687	$ 0.263	$ 2.949
Supporting Functions including management and engineering	$ 1.422	$ 0.389	$ 1.811
Total	$ 9.677	$ 1.853	$ 11.530

<u>Tilbury</u>

The Tilbury Base O&M will require an additional of $1.201 million consisting of $0.856 million for labour and $0.345 million for non labour expenses.

The $0.856 million for labour costs includes the hiring of two additional maintenance employees at an approximate cost of $0.274 million and $0.582 million for full year funding for positions hired part way through 2018. In 2018, six new positions were added part way through the year at an approximate cost of $0.353 million. An additional $0.582 million is required in the Base O&M representing the full year cost for the positions.

The remaining incremental costs of $0.345 million include $0.295 million for additional contractor support for maintenance of the facility and $0.050 million for fees and permits.

<u>Mt. Hayes</u>

The Mt. Hayes Base O&M will require an additional $0.263 million comprised of $0.048 million for additional contractor support to support the reliability of the plant, $0.123 million for an additional maintenance employee, and $0.092 million for full year funding for a positon hired part way through 2018. In 2018, one position was added part way through the year at an approximate cost of $0.035 million. An additional $0.092 million is required in the Base O&M representing the full year cost of the position.

<u>Supporting Functions</u>

$0.250 million is required in the Base O&M for one additional operations manager, one safety and compliance manager and related employee expenses and full year funding for a management position hired part way though 2018, with costs offset partially with expected cross charging of labour to capital activities. Additionally, $0.139 million is required for contractor work related to developing technical standards, as well as continual improvement and maintenance of the IMP for the LNG group within the safety and loss management program, and for technical software license fees. This is necessary to ensure compliance with the BC OGC requirement to develop and maintain a safety and loss management program.

Since the flow-through O&M amounts are based on the most recent forecast of LNG throughput, and will change as LNG sales activity evolves, FEI is not seeking approval of the flow-through

[126] Adjusted Base of $9.677 million includes $9.469 million proposed reallocation of 2018 actuals to base plus 2019 inflator factor of 1.02198 ($0.208 million).

amounts in this Application, but will forecast these costs each year in the Annual Review process.

2.4.2.3 New Funding for Term of Proposed MRP

FEI's requirements for increased O&M funding over the term of the Proposed MRP are influenced by a number of drivers. FEI requires incremental O&M funding added to its 2019 Base O&M to address these future issues and challenges in its operating environment, including changes in regulations, compliance requirements, customer expectations, growing customer base, and climate policy.

The following table and discussion describes the incremental O&M funding required over the term of the Proposed MRP, organized by the themes and broad-based business drivers discussed in Section B1.

Table C2-7: FEI New Funding for the Term of Proposed MRP

Incremental to Base	$ millions
Customer Expectations	$ 1.360
Engagement	$ 3.360
Indigenous Relations	$ 0.888
System Operations, Integrity and Security	$ 4.808
Total	$ 10.416

2.4.2.3.1 CUSTOMER EXPECTATIONS

As discussed in Section B.1.3.3 Providing Cost Effective Energy Solutions, offering cost effective, accessible and innovative energy solutions is a cornerstone of our future and, therefore, our focus. Table C2-8 below provides a summary of the proposed Customer Expectations incremental funding request to support this key priority. Historical expenditures since the start of the Current PBR Plan in 2014 are provided for context along with the available funding in 2019. The proposed incremental funding represents the additional funds to be added to the 2019 Base O&M.

Table C2-8: FEI Customer Expectations

	Historical Expenditures ($ millions)					Base	Proposed	Proposed
	2014	2015	2016	2017	2018	2019	2019	Incremental
Connect to Gas	$0.977	$2.100	$2.227	$2.112	$2.276	$2.380	$3.580	$1.200
In-house Resources to address customer preferences	$0.051	$0.072	$0.125	$0.027	$0.271	$0.271	$0.431	$0.160
Total	$1.028	$2.172	$2.352	$2.139	$2.547	$2.651	$4.011	$1.360

FEI is requesting an incremental $1.200 million to continue efforts focusing on customer growth and retention through its "Connect to Gas" activities. Activities under the "Connect to Gas" umbrella have supported the addition of new customers, fostered customer retention and helped increased the adoption of additional natural gas appliances. This will help to mitigate rate pressure, contribute to keeping natural gas affordable and maximize the use of FEI's energy delivery systems for the benefit of customers.

Connect to Gas

Table C2-9 below outlines the different types of proposed incremental expenditures for "Connect to Gas" activities. Each category of incremental expenditures is discussed below the table.

Table C2-9: FEI Connect to Gas Incremental Funding

Anticipated Breakdown of Expenditures	Incremental Funding ($ millions)
Advertising – New and Conversion Customer Additions	$ 0.600
Natural Gas Appliance Incentives	$ 0.350
Stakeholder Engagement	$ 0.250
Total	$ 1.200

Advertising – New Customer Additions and Conversions - $0.600 million

Advertising and outreach efforts have played an important role in increasing awareness of FEI's programs, incentives and appliance solutions which, in turn, informs customer decisions. Campaigns have focused on educating customers on cost impacts, ease of attaching to the natural gas system, as well as technologies that may be suitable for customers' heating and appliance needs.

Advertising initiatives that help increase customer energy literacy have produced positive results. Campaigns help FEI educate customers on the use of natural gas – its affordability, versatility and lifestyle features. Outreach also helps to educate customers on FEI's product offerings and how they can support their personal and/or business objectives. Various channels are used including out of home advertising, such as Skytrain and bus shelter ads, digital media, as well as fleet vehicle decals.

Although FEI has been successful in adding new customers in recent years, the current market environment is becoming increasingly complex with numerous sources of information on energy options, making it challenging for customers to decipher information to make informed choices that meet their needs. For instance, many British Columbians are not using natural gas despite their proximity to the natural gas distribution system. In many cases, they are using alternative fuels such as oil or propane and have expressed a strong desire to become natural gas customers.

FEI needs to increase its communication efforts to make customers aware of the programs under the "Connect to Gas" umbrella and the incentives that are available that make natural gas more accessible and enable FEI to assist these customers in switching from higher emission fuels to natural gas.

FEI will also need to increase its communications efforts to respond to the changing market landscape that is being driven by multiple factors such as changing customer expectations, new technologies and new entrants in the energy space. The goal is to maintain or grow throughput on the system by educating and informing customers about the use of natural gas.

Natural Gas Use and Appliance Incentives - $0.350 million

FEI is seeking additional incentive funds to help with its efforts to retain customers and encourage the adoption of additional natural gas appliances in residential homes.

Our data shows that currently there are over 54,000 customers in the Vancouver Island area alone who are within 30 metres of a natural gas main and would benefit from accessing the Connect to Gas program. FEI's investment in incentive programs[127] will allow FEI to better serve customer needs by providing them access to a cost effective and cleaner energy source (in most conversion projects), and enable FEI to mitigate rate increases to existing natural gas customers.

Incentives have demonstrated their effectiveness in influencing the market to use natural gas and install natural gas appliances in new developments. There is a need to implement additional incentives to move to new technologies in response to the changing market and building landscape. For example, appliance options such as wall furnace units that are compact in size will support natural gas heating in basement suites. Another initiative is basement suite metering, which will enable landlords to separate the utility costs for the occupants of a suite, and allow the occupants to have the opportunity to benefit from affordable energy costs and control their own usage with the separate metering.

The need for a natural gas solution for the condominium market is also critical to match the housing trend. Incentives to drive vertical common venting is an innovative solution towards having full, individualized load in multi-family condominiums. The venting requirements of gas appliances and associated costs is making it difficult for customers who reside in high and low rise condominiums to access natural gas. Vertical common venting leverages existing technology of combination systems (most commonly seen in townhouses) and will allow FEI to serve this market by leveraging incentives.

In 2014, there were a total of 763 participants that received incentive funding under the "Connect to Gas" umbrella. This has increased to 1,312 participants in 2018. Participant results to date confirm that customers consumed less energy, reduced GHG emissions and lowered their operational costs as a result of connecting to lower cost natural gas and using

[127] Incentives have been offered to convert from a high carbon energy source to lower carbon natural gas. As noted in the 2018 Annual Review, this component of the Connect to Gas initiative was previously referred to as "Switch & Shrink".

high efficiency natural gas equipment. Incentives also helped influence new conversion customer additions. FEI has seen a 150 percent increase in conversion customers since 2014, from 1,799 to 4,486.

Collaboration with Stakeholders - $0.250 million

As the market environment becomes more complex, it is important for FEI to increase its efforts in engaging and collaborating with stakeholders who are influencers in the market. There is a diverse group of stakeholders that have an impact on the acceptance and adoption of natural gas. These stakeholders range from builders, developers, and architects to appliance manufacturers and distributors. FEI needs to engage closely with such partners. This includes investment in activities such as lunch and learn sessions, campaigns, collaborative case studies and pilot programs.

In summary, FEI is committed to furthering its outreach and collaboration with customers and stakeholders. The $1.200 million additional funding request will enable FEI to continue to meet evolving customer needs and expectations, which allows FEI to both attract and retain customers to maximizing the use of its energy delivery systems for the benefit of customers.

In-House Resources to Address Customer Communication Needs

FortisBC's customers value ease of interaction, convenience, and responsiveness. In addition, customers now expect flexible communication channels and proactive communication from the utility to allow for informed customer choice and decision making. This is a notably different environment from the recent past when customer engagement was traditionally on the utility's terms and on a transactional basis.

Changes in customer preferences provide an opportunity to leverage technology and connect with customers at a different level. Interactions through non-traditional channels such as text messaging, mobile applications and social media offer a means to engage the customer more closely in order to continue to strengthen the relationship with FortisBC as their energy advisor.

Additional in-house resources including a Digital Advisor and Communications Writer/Researcher are required to support these activities. Total funding required is $0.200 million with FEI's share $0.160 million (80 percent) and FBC's share $0.040 million (20 percent).

2.4.2.3.2 ENGAGEMENT

As discussed in Section B.1.4 Stakeholder Engagement and Indigenous Relations, as energy and environmental policies shift and the Companies' operating environment evolves, expectations for public consultation and engagement increase.

Table C2-10 below provides a summary of the proposed Engagement incremental funding requests. Historical expenditures since the start of the Current PBR Plan in 2014 are provided for context along with the available funding in 2019. The proposed incremental funding represents the additional funds to be added to the 2019 Base O&M.

Table C2-10: FEI Engagement Incremental Funding

	Historical Expenditures ($ millions)					Base	Proposed	Proposed
	2014	2015	2016	2017	2018	2019	2019	Incremental
Raising Awareness for Consumers in a Lower Carbon Future	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.000	$ 2.000
Climate Action Partners program	$ -	$ -	$ -	$ 0.414	$ 0.211	$ 0.400	$ 1.400	$ 1.000
Other Supporting Resources	$ -	$ -	$ -	$ 0.110	$ 0.110	$ 0.110	$ 0.470	$ 0.360
Total	$ -	$ -	$ -	$ 0.524	$ 0.321	$ 0.510	$ 3.870	$ 3.360

Each of the listed items is discussed below.

Raising Awareness for Consumers in a Lower Carbon Future - $2.000 million

FEI delivers affordable, clean-burning natural gas to over one million customers in the province while also providing innovative energy solutions, including RNG, NGT and DSM programs, which help customers meet their energy and emissions objectives. FEI's infrastructure will play a key role in supporting the transition to a lower carbon future and, as discussed in Section B 1.4.4 Research on Enhancing Stakeholder Communication, educating customers and the public on the important role of natural gas and FEI's infrastructure is necessary to maintain and stimulate new demand while meeting our customers' energy needs.

Increasing public and customer awareness of FEI's traditional and innovative energy solutions is not only key to developing new demand, but it is also essential for demonstrating that FEI is meeting customer expectations in bringing forward energy solutions that are innovative, cost effective and that have lower emissions. This supports FEI's ability to attract and retain customers, and has important implications for FEI as research confirms that it costs four to five times more to win back a customer than to keep an existing one.

While significant funding has been committed to initiatives including safety and energy efficiency over the past several years, no funding has been allocated to increasing awareness of FEI's products and services and their fit within a lower carbon economy. The incremental funding is required to address this gap. According to an FEI survey in 2018, only 41 percent of consumers identified as being very familiar with FortisBC. Messages that communicate what FEI is doing for communities, customers and the environment will retain customers, promote increased demand, and protect the viability of the energy delivery system.

Raising awareness will occur through an annual investment in advertising and will consist of various media channels strategically placed throughout the year with consistent messaging. The incremental annual total of $2.0 million translates to an approximate 85 percent reach to British Columbians an average of 33 times over a one-year period. This level of funding is appropriate and necessary in order for the messaging to provide good awareness and recall for British Columbians, and will be achieved through an annual 26-week campaign over various communications channels including television, digital platforms and out of home sites. This repeated messaging will ensure that customers are aware of how FEI's products and services can meet their needs even in a lower carbon future.

Climate Action Partners program - $1.000 million

As described in Section B.1.4.3 Partnering for Climate Action, it is important for FEI to work closely with key stakeholders so that both FEI's suite of services and customer interests are considered in broad-based GHG reduction agendas. All levels of government have signalled that electrification is expected to play a large role in B.C.'s energy transition, and also noted are some of FEI's initiatives such as renewable gas, NGT and LNG bunkering. The Climate Action Partners program increases understanding and adoption of the services we provide. FEI must be involved in assisting government in understanding specific barriers and opportunities for utility infrastructure and energy services delivery so that gas utility interests are considered in future policy planning and development.

The $1.0 million in incremental funding is required to increase relationship building efforts with federal, provincial and local governments on policy planning and implementation. Following a similar path as the CoV, other local governments throughout B.C. have adopted aggressive renewable energy and climate action targets, and FEI will need to commit additional effort and resources toward ensuring access to natural gas services for residents and customers. The Climate Action Partners program also supports public sector organizations, Indigenous communities and stakeholder partnerships by providing resources to develop, deliver and promote FEI's renewable and low carbon energy solutions throughout B.C. such as identifying opportunities to upgrade to more energy efficient natural gas appliances, or switching medium and heavy duty diesel fuel users to CNG or RNG.

The Climate Action Partners program provides an important means to educate our stakeholders on FEI's energy offerings and on the role of the gas delivery system in driving progress toward the province's CleanBC targets.

Table C2-11 below provides details of the funding and activities planned.

Table C2-11: FEI Climate Action Partners Program Incremental Funding

Climate Action Partner Program Funding Request	$ millions
Senior Energy Specialists Roles and associated administration	$ 0.570
18 positions in total (8 positions fully funded at 100% and 10 positions partially funded at 80%)	
Total funding $1,650 thousand with $570 thousand funded in O&M and remaining $1,080 thousand as part of C&EM funding.	
Expanding the program's partnerships with indigenous communities, non-profit and academic organizations	$ 0.180
Targeted support to stakeholders (i.e. supporting climate action workshops, investing in events to educate FortisBC's customers of the Company's low carbon and renewable energy solutions)	$ 0.250
Total	$ 1.000

As set out above, FEI is planning to expand the Climate Action Partners program by:

- Funding additional Senior Energy Specialist roles. For these roles, FEI provides funding to various levels of government, Indigenous communities and other organizations to hire a person to implement a pre-defined work plan that aligns with the organizations' energy objectives. Only seven municipalities, the provincial Climate Action Secretariat and the Port of Vancouver are currently covered, with interest expressed by many more organizations looking to participate in the program. The additional funding will be used to increase the number of Senior Energy Specialist roles by 18 positions from today's nine, providing service more broadly to all parts of the province. The percentage of funding for the positions can be either 100 percent or 80 percent depending on the geographical location of the position. Total funding for these positions ($1.650 million) will come from approved DSM funding ($1.080 million) and O&M funding ($0.570 million).
- Expanding the program's partnerships with Indigenous communities, non-profit and academic organizations to leverage the unique expertise and communication channels of these partners. This will help educate, promote and implement low carbon energy solutions. Activities include providing strategic support through sponsorships, training, education, workshops and multilevel communications to ensure initiatives are effective.
- Providing targeted support to stakeholders including supporting climate action workshops, investing in events to educate FEI's customers about available low carbon and renewable energy solutions, and promoting dialogue on the role of the gas system in achieving the province's CleanBC targets.

The Climate Action Partners program enables FEI to further strengthen awareness of the role of the gas system and its products and services while gaining a direct and immediately accessible line of communication with local government organizations. This is important as public sector organizations continue to look for ways for their organizations and communities to become carbon neutral. This program provides a unique means for FEI to assist its customers through local governments, Indigenous communities and other strategic partners in contributing to CleanBC objectives through a variety of low carbon and renewable energy solutions.

Other Supporting Resources - $0.360 million

As described in Section B.1.4.2 Enhanced Project Consultation and Engagement, greater expectations for regulatory and public engagement mean that FEI will need to increase consultation with stakeholders and right holders. The following is a discussion of the additional resources to address overall stakeholder engagement expectations.

Web-Based Platforms Support

FortisBC uses two web-based platforms to communicate with customers and school-based stakeholders, Talking Energy and Energy Leaders. Funding for an additional Digital Communications Advisor position and supporting costs is required to support ongoing changes to the sites and to draft additional content. Without the additional resources, the Companies' web-based platforms will become outdated and less timely, and our communication reach limited.

Total funding required is $0.200 million with FEI's share $0.160 million (80 percent) and FBC's share $0.0400 million (20 percent).

Program Development

This funding is required for early stage policy and program development including legal fees associated with regulatory developments. As an example, there are jurisdictional considerations pertaining to the federal government's Clean Fuel Standard as it potentially overlaps with the Provincial government's Renewable and Low Carbon Fuel Requirements Regulation. Additional funds will allow for investigation of legal considerations at the early stages of policy and regulatory development, which will enable more timely and effective customer advocacy for policies and regulations that will mitigate risk and increase customer benefits by reducing longer-term compliance costs.

Total funding required is $0.200 million.

2.4.2.3.3 INDIGENOUS RELATIONS

As discussed in Section B.1.4.1 Expanding Indigenous Relations Efforts, Indigenous relationships are critical to continue to provide safe and reliable utility service through capital infrastructure projects. Table C2-12 below provides a summary of the proposed incremental funding requests to renew and strengthen Indigenous relationships, particularly with respect to access to land. Historical expenditures since the start of the Current PBR Plan in 2014 are provided for context along with the available funding in 2019. The proposed incremental funding represents the additional funds to be added to the 2019 Base O&M.

Table C2-12: FEI Indigenous Relations Incremental Funding

	Historical Expenditures ($ millions)					Base	Proposed	Proposed
	2014	2015	2016	2017	2018	2019	2019	Incremental
Relationship Protocol Agreements with the Indigenous community	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.488	$ 0.488
Indigenous Community Investments	$ 0.054	$ 0.096	$ 0.092	$ 0.096	$ 0.096	$ 0.096	$ 0.296	$ 0.200
Indigenous Supporting resources	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.200	$ 0.200
Total	$ 0.054	$ 0.096	$ 0.092	$ 0.096	$ 0.096	$ 0.096	$ 0.984	$ 0.888

Each of the items listed in the table is discussed separately below.

Relationship Protocol Agreements with the Indigenous Community

Given the elevated status of UNDRIP implementation at both the federal and provincial levels of government, incremental O&M resources (2 additional positions and support funding) are required to renew and strengthen Indigenous relations, particularly with respect to access to land. As indicated in the most recent Speech from the Throne, B.C. intends to become one of the first provinces in Canada to introduce legislation to implement the UNDRIP. There are over

46 articles contemplated in the UNDRIP with 203 First Nations, the most frequently quoted for B.C. pertains to "obtaining free, prior and informed consent" from Indigenous people before approving "any project" affecting their lands or territories and other resources. Additional work and funding is required to enhance FEI's consultations with Indigenous communities and to begin modernizing Indigenous operating arrangements. Annual increases in related legal costs for negotiations, engagement and capacity funding will also be required. The consequence of not undertaking this work is failing to obtain project permit approvals, license to operate throughout Indigenous communities as well as a higher cost to implement projects in the longer term if engagement and consultation are not addressed upfront.

Indigenous Community Investments

Additional funding for community investments and sponsorship is required to build capacity in the Indigenous communities in which we operate, and is also related to the changing external environment and increased expectations for engagement.

Indigenous Supporting Resources

FEI requires $0.140 million for an Indigenous Employment Advisor to support Indigenous activities. This position will focus on the employment, training, awareness and engagement of Indigenous candidates. An additional $0.060 million is required for consultant support to help with the upcoming Indigenous land code issues.

2.4.2.3.4 SYSTEM OPERATIONS, INTEGRITY AND SECURITY

As discussed in Section B.1.5 System Operations, Integrity and Security, our operations are focused on meeting customer expectations by improving processes concerning the efficient and effective completion of work. Table C2-13 below is a summary of the proposed funding requests. Historical expenditures since the start of the Current PBR Plan in 2014 are provided for context along with the available funding in 2019. The proposed incremental funding represents the additional funds to be added to the 2019 Base O&M.

Table C2-13: FEI System Operations, Integrity and Security Incremental Funding

	Historical Expenditures ($ millions)					Base	Proposed	Proposed
	2014	2015	2016	2017	2018	2019	2019	Incremental
System Operations, Integrity and Safety								
Integrity Management	$ 3.500	$ 4.000	$ 4.900	$ 5.000	$ 5.300	$ 6.200	$ 7.550	$ 1.350
Maintaining System Infrastructure	$ 38.800	$ 38.900	$ 40.500	$ 40.700	$ 43.200	$ 44.200	$ 44.900	$ 0.700
Operations Compliance and Safety	$ 15.700	$ 17.000	$ 19.000	$ 19.200	$ 19.500	$ 19.600	$ 20.200	$ 0.600
Cyber Security	$ -	$ -	$ -	$ -	$ 0.676	$ 1.312	$ 1.820	$ 0.508
Data Analytics	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.300	$ 0.300
Gas Control	$ 1.686	$ 2.113	$ 2.235	$ 2.156	$ 2.206	$ 2.580	$ 3.230	$ 0.650
CEPA Participation	$ -	$ -	$ -	$ -	$ -	$ 0.100	$ 0.800	$ 0.700
Total	$ 59.686	$ 62.013	$ 66.635	$ 67.056	$ 70.882	$ 73.992	$ 78.800	$ 4.808

Each of the listed items is discussed below.

System Operations, Integrity and Security

Integrity Management - $1.350 million

FEI needs to continue to improve its IMP to remain in compliance with CSA Z662-15 and adopt industry practices. Due to FEI's aging infrastructure, there is an increasing risk of time-dependent failure mechanisms, such as corrosion. To manage these mechanisms and risk of failure, FEI needs to expand its current IMP for pipeline assets to include facilities (e.g., compressor stations), to perform incremental asset condition assessments of non-piggable assets (e.g., non-piggable laterals and buried facilities piping), and to enhance its current lifecycle integrity management practices for its transmission pipelines.

Standard CSA Z662-15, published in June 2015, and CEPA membership requires pipeline operators to continually improve practices. Consistent with this requirement, industry practices and technology have evolved significantly in recent years. Specifically, in part to respond to pipeline failures due to time-dependent threats such as corrosion, the industry has focused on systems to manage these threats and is increasingly adopting in-line inspection technologies where they are proven commercially. Consistent with industry practice, FEI has determined that it is prudent to continue the application of proven commercialized in-line inspection technologies.

The funding will enable FEI to expand its current integrity management system for pipelines to facilities such as compressor stations, to perform incremental pipeline condition assessments of non-piggable assets, and to progress in a timely manner towards implementation of evolving integrity management practices for transmission pipelines. Activities included are inspection of non-piggable transmission pipe (e.g., facilities piping in stations), and inspection and assessment of compressor stations.

The incremental funding is separate from the IGU and Transmission Integrity Management Capabilities (TIMC) projects. The IGU project is focused on transmission pipelines that are 6 inches and larger, as that is currently the smallest diameter for which proven commercialized ILI tools exist. Following the implementation of the IGU project, FEI will still have some non-piggable transmission pipe. This includes transmission pipe less than 6 inches, as well as short segments of pipe within stations (e.g. compressor stations, transmission valve stations, connections between looped lines, etc.). The TIMC project is focused on providing FEI with the capabilities required for adoption of crack-detection tools for selected pipelines within its in-line inspection program.

Not included in this category are the costs of the integrity digs resulting from running ILI tools. As there is uncertainty regarding the impact of the ILI results on the extent of integrity digs required during the Proposed MRP, FEI proposes to treat the costs of integrity digs as a flow through item, outside of formula O&M as discussed above in Section C2.4.2.2.3.

Maintaining System Infrastructure - $0.700 million

FEI is adding new assets each year and requirements are changing as technology advances. As a result, equipment and systems are more complex and need more site or asset-specific maintenance planning and execution. Existing infrastructure is also aging and requires more frequent maintenance to extend its life, and minimize life cycle costs. Maintaining both aging and new infrastructure appropriately helps prevent major outages, ensures security of supply, and enables the system to operate according to design parameters.

FEI therefore needs to hire a Maintenance Planning Engineer and a Maintenance Planner to enable continuous improvement of the FEI asset management strategy.

In addition, Vancouver Island line heaters will be undergoing inspections in accordance with internal standards. Some line heaters have not been maintained for several years as they could not be pulled out of service due to lack of redundancy. In recent years, capital programs have added redundancy or the ability to bypass, making the inspection and maintenance work possible without service interruption. These heaters, along with the additional heaters installed for redundancy, now require maintenance activities to be undertaken.

Operations Compliance and Safety - $0.600 million

Codes, regulations, FEI standards and industry practices continue to evolve and FEI needs to comply with the requirements. Additional resources (i.e., construction crews, OSRs) are required to enable compliance with current codes, regulations, internal standards and agreements.

The following are items that are driving the need for additional resources and funding:

- Vehicle safety – Improving vehicle safety by implementing improved vehicle ergonomics and outfitting the fleet with minor enhancements such as slip resistant steps, improved binning, and high visibility stripping as required.
- Encroachments - FEI is experiencing right of way encroachments that are limiting the ability to access the pipelines safely and reliably. Legal guidance is needed to successfully resolve the encroachment issues.
- BC One Call - Responding within 48 hours to requests for information from people planning to dig around underground gas assets is a legal responsibility in the Gas Safety Act. BC One Call Ticket volumes continue to increase annually and additional resources are required to meet response time requirements in the best interests of customers and improve public safety in and around gas lines.
- FEI Construction Crew Resources - FEI needs additional construction crews because of retirements and increased maintenance requirements. Funding is required for the training of these employees.

Cyber Security - $0.508 million

In recent years, FortisBC has increased expenditures for cyber security as the Companies respond to the evolving cyber risks. Additional resources provide the ability to implement and maintain technologies that recognize and address the increased threat landscape, support the ability to respond to cyber security events, keep the Companies' systems secure, and manage risk to the gas distribution system. The new resources will also be required to actively identify and respond to cyber security threats through participation in industry groups, security audits and internal investigations.

The threat landscape has evolved and malicious persons are becoming more advanced. There has been an increase in phishing scams, not only online but via phone and even in person. In some cases, these scams are targeting FortisBC customers with the goal of gaining access to customer funds or information. FortisBC believes that an increased cyber security focus in support of our customers is required to prevent these types of scams from being successful.

The total additional resources are comprised of three positions: one customer-focused cyber security position (shared between FEI and FBC) and two operational technology cyber security positions, each at an average cost of $0.150 million per position. The remaining costs are for managed service and tools such as increased end-point licensing and enhanced security awareness to secure, and manage risk to the gas distribution system while maintaining reliability.

Data Analytics – $0.300 million

Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions.

The requested funding is for additional staff required to support the increased use of data analytics at FortisBC. The costs are shared - $0.300 million for FEI and $0.099 million for FBC.

All businesses have data that can be assessed, analyzed and used to inform decision-making. Better decisions will lead to improved business operations and customer services. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. Neither FEI or FBC a centralized data repository, meaning that information across all aspects of the business is currently kept in separate systems.

FortisBC expects to bring on new data sources in priority sequence over the term of the Proposed MRPs. As the amount of data and the breadth of analytic tools available increases, the number of staff required to support analysis will increase. The staff will be used to:

- Create and maintain a centralized data source easily accessible by FEI and FBC employees (subject to appropriate restrictions on sensitive and personal information).

- Create and manage the data extraction and transformation processes.
- Provide training and support for standardized analytics tools to employees.
- Provide centralized advanced analytics services.
- Support a governance committee that will oversee data analytics at FortisBC and create appropriate guidelines and policies for use and analysis of data.

Data analytics initiatives identified to date that FortisBC will further develop are described below.

Reducing planned customer outages

By combining field work from different sources together (e.g., maintenance work orders, system growth projects, new customer installation and upgrade requests) and using accurate system connectivity models (e.g., GIS, SCADA), FortisBC expects to be able to combine more scheduled work during the same planned outage windows. This will reduce the number and total duration of customer outages.

Improved asset management

Machine learning techniques combined with data from multiple sources (SCADA, AMI, pictures, videos, field work orders, weather information) can create asset failure prediction scores, asset health indices, predictive analytics, historical trending, relational trending and notifications/alerts. This would reduce the likelihood of unplanned failures and potentially allow assets to be in service longer.

Optimizing workforce deployment

Using multiple data sources including employee turnover, regional workloads, trends in skill set requirements, house prices, and salary data, FortisBC expects to be better able to predict where and when employees may be required, and the type of skill sets they are likely to require.

Predicting Gas Line Hits – FEI only

Using data from external sources such as building permits and BC One Call tickets, and internal data such as new service installations and real-time localized gas flows, we expect to be able to predict areas with a higher probability of gas line hits. This will enable FEI to take a variety of pro-active measures to mitigate the risk of gas line hits, methane emissions, public and employee safety risk, and consequent service interruptions to customers.

Gas Control - $0.650 million

Incremental funding for four additional gas controller positions will allow FEI to provide two-person Gas Control room coverage on a 24/7 basis. Further, the incremental funding includes operating costs for additional SCADA communications lines to enable system monitoring of increased field devices.

Gas Control provides 24/7 monitoring, control and emergency response functions, as well as gas load tracking and forecasting to support Gas Supply in managing gas supply requirements.

Gas Control's primary focus is on monitoring, controlling and responding to alarms on the FEI transmission and intermediate pressure assets, which includes liaising with interconnecting pipelines such as Enbridge, TransCanada, and Williams Pipelines, liaising with customers in managing gas loads, dispatching transmission, compression and measurement crews for emergency responses, and coordinating outages for gas assets.

Gas Control is also responsible for generating daily gas consumption forecasts for the various FEI service territories, which are used by Gas Supply for nomination and balancing purposes. On a daily and hourly basis, Gas Control makes the determination of the sourcing of gas, based on Gas Supply nominations, operational status of the system, gas load balancing, and changes in the weather forecast.

The proposed Gas Control staffing level is necessary to ensure FEI will be able to meet the requirements of its customers, align with industry standards, and continue to operate in a safe and reliable manner. Current staffing levels allow two persons during the day and one person at night to oversee the entire province of BC, with occasional gaps of only one person during the day as well. These current levels present increasing challenges in responding to alarms and emergencies in a progressively complex and demanding operational environment. They are also among the lowest coverage levels compared to regional industry peers, both local distribution and transmission pipeline companies. The proposed increased staffing will bring FEI's Gas Control Room coverage up to two Gas Controllers at all times, on a 24/7 basis. This will provide more appropriate coverage for normal FEI operational requirements so that there are enough resources and attention devoted to monitoring and ensuring the safe operation of the entire FEI gas network, and will be closer in line with the level of control room coverage provided by other companies within our peer group.

Canadian Energy Pipelines Association Participation - $0.700 million

As discussed in Section B1.5.1.3, FEI has joined CEPA as an Integrity First Partner. During 2019, FEI will be working with CEPA to establish a baseline performance level and an action plan for any areas identified as requiring improvements. At this time, FEI is forecasting expenditures of approximately $0.400 million related to annual membership fees and additional resources (senior engineer) to meet the required performance level (i.e., level 3, "Continually Improving"). Additionally, $0.300 million is required for Gas Control costs. The costs are comprised of $0.165 million for a Gas Control employee to handle the additional auditing, reviewing and reporting duties and $0.135 million for non-labour expenditures required for the implementation of CEPA defined control room management practices as part of CEPA membership requirements.

Control room management improvements driven by CEPA are focused on risk reduction, such as improved SCADA system security, quicker operator response times, and minimization of operator risk. These improvements include the development and implementation of the following: cyber security policies, alarm management philosophy, emergency response protocols, and operator fatigue management strategies.

2.5 *FBC O&M BASE*

2.5.1 O&M Spending from 2013 to 2018

Since the outset of the Current PBR Plan, FBC's O&M spending has trended favourably, both in total and on a per customer basis.[128] FBC's O&M per customer also compares favourably to other peer utilities. As shown in the FBC Benchmarking Study in Appendix C2-2 and discussed in Section B.2.4, FBC's Distribution O&M and Total A&G per customer compares favourably (i.e., below the median) to the Canadian medians and the Pacific Northwest U.S. peer companies group median on a dollar-per-customer basis. The Benchmarking Study also shows that FBC had a similar annual growth rate as its peers for its distribution O&M and total A&G per customer. This means that FBC was able to maintain its favourable position relative to its peers over the period of the study. These results confirm that FBC has been successful in realizing efficiencies and costs savings for the benefit of customers as a result of a broad based productivity focus.

2.5.2 Proposed 2019 O&M Base

FBC is using the 2018 actuals expenditures as the starting point for the O&M Base as it is representative of FBC's current level of O&M funding required to operate its system safely and reliably, maintain its overall service quality level and is reflective of the cost pressures that FBC has been managing in recent years. Examples of cost pressures recently discussed in the Annual Reviews include cyber security and additional staffing needs. Additionally, 2018 actual expenditures reflect efficiencies and productivity improvements, as evidenced by FBC's ability to contain 2018 actual O&M below the formula O&M level, which includes the cumulative impact of the annual PIF of $8.5 million[129] approved as part of the Current PBR Plan.

Using the 2018 actual expenditures as the starting point for the O&M Base, adjustments are then made to arrive at the 2019 Base. The adjustments are as follows:

- Add back temporary O&M net savings included in the 2018 actual expenditures and the corporate and shared services adjustments that result from the updated studies included in Sections D4 and D5;
- Multiply by the 2019 formula inflator as approved in the Annual Review for 2019 Rates[130];
- Adjust for approved 2019 exogenous factors, items held in deferral accounts in the Current PBR Plan that are now included in Base O&M, and items currently in O&M that will be recorded in a deferral account in this Proposed MRP (and vice versa); and
- Add new incremental funding required for the upcoming MRP term.

[128] Figure B2-2 in Section B2.2.1.2 O&M Expenditures.
[129] Section B2.3.1.2, equal to total Current PBR term savings of $12.0 million less 2019 projected savings of $3.5 million.
[130] Financial Schedule 3, FBC's Compliance filing Order G-246-18 for Annual Review for 2019 Rates.

The goal of these adjustments is to determine the appropriate starting point for O&M expenditures in the upcoming MRP period, incorporating known and measurable adjustments as appropriate.

Using the above method, the 2019 Base O&M is calculated as shown in the following table. Each adjustment is discussed below.

Table C2-14: FBC 2019 Base O&M[131]

2018 actual Base O&M	$	53.839
Add temporary savings		0.500
Corporate/Shared Services Studies Impact		0.705
Adjusted 2018 Base O&M	$	55.044
2019 Inflator		1.02382
2019 Base O&M before adjustments	$	56.355
Adjustments:		
Exogenous Factors:		
2019 Z factor (EHT net of MSP)		0.240
2019 Z factor - MRS		1.540
Deferrals:		
Manual meter read		0.180
Flow Through treatment:		
AMI Project cost reductions		(1.161)
BCUC levies		(0.231)
Total adjustments		0.568
New funding for MRP term	$	0.763
2019 Base O&M	$	57.686

On a per customer basis, this translates to $416 ($57.686 million divided by 138,649 customers). To calculate the average number of customers, similar to FEI, FBC has used a 12-month average forecast.

2.5.2.1 Temporary 2018 Net Savings

Of the total net O&M savings above the formula achieved in 2018 of $0.940 million, approximately $0.5 million for bad debts, representing approximately one percent of the overall

[131] Corporate/Shared Service Impact is comprised of the 2019 amount of $0.367 million for Corporate Services (Section D5) and $0.338 million for Shared Services impact (Section D4).

O&M funding, were temporary savings that are not sustainable and will be required in the Proposed MRP term.

Bad debt expense is difficult to forecast as it affected by a number of factors including demand from customers which may be impacted by weather, changes in the price of electricity, success of FBC's collection management practices, and general economic conditions which may impact the ability of customers to pay. In setting its bad debt funding required for a year, FBC considers and relies on actual historical bad debt expense to arrive at a reasonable forecast for bad debt expense.

In 2018, bad debt expense was very low relative to the previous five years. From 2013 to 2018, the average bad debt expense was approximately $1 million per year compared to the 2018 bad debt expense of $0.5 million. The $0.5 million of bad debt expense experienced in 2018 cannot reasonably be considered to be representative of future bad debt expense. Contributing to the reduction in bad debt was the lower consumption due to the wamer weather experienced in 2018. Therefore, the lower bad debt spending in 2018 of approximatey $0.5 million is considered temporary in nature with funding required in future years to be more reflective of historical levels of bad debt expense. Experience tells us the actual bad debt experienced is typically higher than that observed in 2018.

2.5.2.2 Adjustments

2.5.2.2.1 EXOGENOUS FACTORS

EHT net of MRP

FBC was approved to adjust 2019 O&M for the costs of the new EHT net of the MSP premiums reduction. The net increase of $0.240 million ($0.576 million EHT less the annual amount of ($0.366) million MSP premiums reduction)[132] has been adjusted in Table C2-14 above.

Mandatory Reliablity Standards Increase for Assessment Report (AR 10)

FBC has also been approved to recover incremental costs of MRS compliance not included in Base O&M. The $0.940 million[133] projected in 2019 will be required on an ongoing basis and, as such, will be included as part of the 2019 Base O&M along with an additional $0.600 million for the expected increase in costs beginning in 2020 to maintain compliance with AR 10.

[132] Order G-246-18 reflected the reduction of MSP premiums by 50% in 2019. MSP premiums will be eliminated as of January 1, 2020.

[133] Order G-246-18 and Decision, page 11.

2.5.2.2.2 DEFERRALS

Manual Meter Reading costs

FBC permits customers the option of having an AMI meter installed that has the wireless transmit function disabled. Pursuant to Order G-202-15, FBC has been recording the associated revenue net of expenses in the Radio-off Shortfall deferral account. In its 2017 Cost of Service and Rate Design Application (RDA), FBC proposed to cease recording the net revenue and expenses in the deferral account as of December 31, 2019. This proposal was approved by Order G-40-19.

Effective January 1, 2020, FBC will eliminate the use of the deferral account and include the cost of the meter reads in O&M expense, resulting in an increase in O&M expense to the 2019 Base O&M of $0.180 million which is FBC's estimate of the cost to perform the meters reads. Revenue from the manual meter read fees will be recorded in Other Revenues.

2.5.2.2.3 FLOW-THROUGH TREATMENT

AMI Project Cost Reductions

Incremental O&M costs related to the implementation of the AMI project are being offset by post-implementation savings, resulting in a net decrease to O&M expense after implementation. Because of the high variability of AMI costs and savings during the implementation period, net AMI costs, including the costs of AMI-enabled billing options, were tracked outside of the Current PBR Plan formula during the PBR term.

As the AMI project is now complete, the ongoing savings of $1.161 million have been incorporated into the Base O&M.

BCUC Levies

Under the Current PBR Plan, any difference between the actual BCUC levies paid and the amount embedded in Base O&M is shared equally between FBC and ratepayers through the earnings sharing mechanism. In this Application, similar to FEI, FBC proposes to forecast all of the BCUC levies outside of the O&M formula and to record variances in a deferral account. Refer to the discussion in Section C2.4.2.2 regarding BCUC Levies.

In 2018, the BCUC actual levies were $0.231 million. The $0.231 million will be removed from the Base O&M.

2.5.2.3 New Funding for Term of Proposed MRP

Requirements for increased O&M funding over the term of the Proposed MRP will be influenced by a number of drivers. FBC requires incremental O&M funding added to its 2019 Base O&M to address these issues and challenges in its operating environment, continue to maintain its service levels to customers and address increasing customer expectations.

The following table and discussion describes the incremental O&M funding required over the term of the Proposed MRP, organized by the themes and broad-based business drivers discussed in Section B1.

Table C2-15: FBC New Funding for the Term of Proposed MRP

Incremental to Base	$ millions
Engagement	$ 0.080
System Operations, Integrity and Safety	$ 0.683
Total	**$ 0.763**

2.5.2.3.1 ENGAGEMENT

This $0.080 million for engagement is for FBC's share of resources for supporting web-based platforms and in-house resources as described above in Section 2.4.3.2 for FEI.

2.5.2.3.2 SYSTEM OPERATIONS, INTEGRITY AND SECURITY

As discussed in Section B.1.5 System Operations, Integrity and Security, FBC's operations are focused on ensuring customer expectations are met by improving processes concerning the efficient and effective completion of work. Table C2-16 below is a summary of the proposed funding requests. Historical expenditures since the start of the Current PBR Plan in 2014 are provided for context along with the available funding in 2019. The proposed incremental funding represents the additional funds to be added to the 2019 Base O&M.

Table C2-16: FBC System Operations, Integrity and Security Incremental Funding

	Historical Expenditures ($ millions)					Base	Proposed	Proposed
	2014	2015	2016	2017	2018	2019	2019	Incremental
System Operations, Integrity and Safety								
Tree Management	$ 0.763	$ 0.585	$ 0.186	$ 0.184	$ 0.185	$ 0.268	$ 0.343	$ 0.075
Generation Dam Safety	$ 0.015	$ 0.042	$ 0.019	$ 0.025	$ 0.061	$ 0.130	$ 0.362	$ 0.232
Network Operations Apprentice Program	$ 0.036	$ 0.071	$ 0.080	$ 0.054	$ 0.139	$ 0.068	$ 0.265	$ 0.197
Cyber Security	$ -	$ -	$ -	$ -	$ 0.431	$ 0.515	$ 0.595	$ 0.080
Data Analytics	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.099
Total	$ 0.814	$ 0.698	$ 0.285	$ 0.263	$ 0.816	$ 0.981	$ 1.565	$ 0.683

Each item in the table is discussed below.

Tree Management

FBC is experiencing a high number of outages in the Kootenay area resulting from trees falling on the conductor. Some of these outages have been escalated to the BCUC from Kootenay area customers. These trees are coming from outside the boundaries of the ROW and cannot be removed unless they are assessed and considered unhealthy. FBC has a forest health program where we address problem trees when they are identified. The $0.075 million in funding will allow FBC to hire a qualified professional to identify, assess, and map root rot centres. FBC is working to identify areas where root rot is a concern and will assess the next steps to be taken from a safety and reliability perspective.

Network Operations, Engineering and Generation

Generation Dam Safety - $0.232 million

The funding will enable FBC to better meet the requirements under the BC Dam Safety Regulation by implementing document control, completing required dam safety reviews, and penstock assessments. Dam owners are required to take reasonable care to avoid the risk of significant harm resulting from defects, insufficiency or failure of the dam(s). FBC has no record of condition assessments of the penstocks. Baseline inspections are required to determine the structural condition.

Network Operations Apprentice program $0.197 million

FBC needs to provide reliable service to customers, and maintain SAIDI, SAIFI and trouble response service quality in an environment where employee demographics continues to be a challenge. The FBC apprentice program is not currently producing International Trade Administration apprentices at a rate that meets anticipated demand. It can take up to four years to complete an apprenticeship program. FBC will use these funds to hire four additional apprentices.

Cyber Security

This is for FBC's share of one cyber security position and managed services and tools as discussed above for FEI. The $0.080 million is FBC's share of resources required overall with $0.062 million for managed services and tools and the remaining $0.018 million for FBC's portion of the shared customer cyber security position with FEI.

Data Analytics

Please refer to the discussion in FEI for a description of the Data Analytics funding needs.

In addition to the list of data analytics initiatives common to both FEI and FBC discussed earlier, following is an initiative specific to FBC.

Determining electrical connectivity between meters, transformers and electrical phases

Like many utilities, FBC's electrical system maps at the distribution level are not 100 percent correct. Meters may be connected to the wrong transformer and transformers may be connected to the wrong phase in the GIS model. This problem is not uncommon and can, for example, lead to the wrong customers being identified in outages and imperfect load flow modeling. Utilities traditionally have corrected system maps by physically inspecting the assets. FBC has been working with the University of California and other organizations on statistical techniques that use hourly AMI voltage data and existing connectivity models to mathematically determine meter-transformer-phase connectivity and allow for automated map corrections.

2.6 O&M DETERMINATION DURING THE TERM OF PROPOSED MRPS

Similar to the Current PBR Plans, rates during the Proposed MRPs will reflect the recovery of both indexed-base O&M and forecast O&M. For indexed-based O&M, each year the O&M expense will reflect the previous year's indexed-based O&M per customer amount adjusted by inflation and then multiplied by a forecast of the Average Number of Customers[134] (calculated as the twelve-month average of the forecasted number of customers). For forecast O&M, the Companies will continue to forecast certain O&M expenditures annually as discussed in Section C4.

FortisBC proposes to determine indexed-based O&M on a per customer basis. A 2019 Base O&M is set out above in Section 2.4.2 FEI O&M Base, Table C2-1 and Section C2.5.2 FBC O&M Base, Table C2-13. The 2019 Base O&M is expressed as a function of the average number of customers for 2019, which is referred to as the Unit Cost O&M (UCOM). A 2019 Base UCOM is set by dividing the 2019 Base O&M by a projection of 2019 Average Number of Customers. The Companies' 2019 UCOM is set out in the sections referred to above and is equal to $250 per customer for FEI and $416 per customer for FBC.

The UCOM is then escalated using inflation during the term of the MRP. The inflation factor that FortisBC proposes to use is the same as the one that was approved for the Current PBR Plans and is described in more detail in Section C1.1.3.

In summary, each year's indexed-based O&M is determined by applying an inflation factor to the previous year's UCOM and then multiplying by a forecast of the average number of customers, expressed as follows:

$$OM_t = UCOM_{t-1} \times (1 + I) \times AC_t$$

Where: *OM = Indexed-based Operating and Maintenance Expense*
UCOM = Unit Cost O&M
t = Forecast Year
I = Inflation Factor
AC = Average Number of Customers

FEI and FBC will each forecast the average number of customers (as opposed to lagged actuals in Current PBR) for the rate making year as part of the Annual Review process during the Proposed MRPs and include a true-up to O&M in the following year. The proposed growth factor true-up process, discussed in Section C1.1.4, will recover from or return to ratepayers any O&M variance caused by a difference between the forecast and actual average number of customers and will mitigate any forecast error. The Section C1.1.3 also explains the relationship between the average number of customers and the O&M costs.

[134] As opposed to a 50 percent lagged actuals used in the Current PBR Plans.

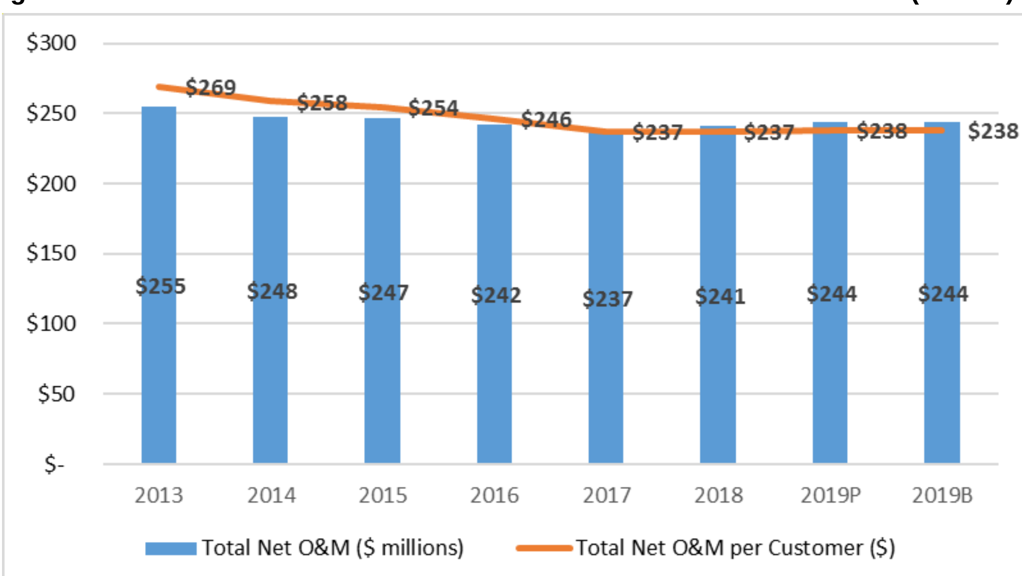
2.7 CONCLUSION

FEI and FBC's proposed 2019 Base O&M requirements are reasonable and necessary to provide safe and reliable service to customers. FortisBC has been a responsible steward in prioritizing and managing its overall O&M expenditures during the term of the Current PBR Plans and will continue to do so over the term of the Proposed MRPs.

In Section B2.2.1.1 and B2.2.1.2, FortisBC discussed the recent trends in Gross O&M, both in total and on a per customer basis. Since many of the drivers of increase O&M costs for FortisBC are related to increasing capital activities, it is important to also consider Net O&M (after capitalized overhead).

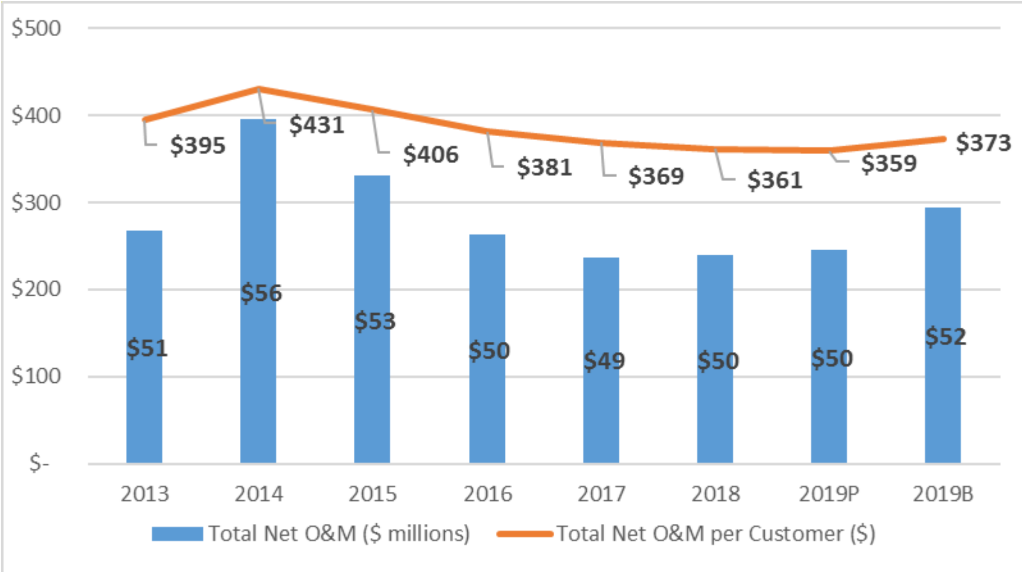
When viewed on a Net O&M per customer basis, spending has also trended downwards for both FEI and FBC during the term of the Current PBR Plans while service quality levels were maintained. Additionally, as shown in Figures C2-1 and Figure C2-2 below, FEI's and FBC's proposed 2019 Base O&M, even with the incremental funding proposals, is lower on a Net O&M per customer level basis compared to the start of the Current PBR Plans. This reinforces that there are permanent savings from the Current PBR Plans that have been embedded in the O&M levels going forward.

Figure C2-1: FEI Actual Net O&M in Real Dollars from 2013 to 2019 Base (2019 B)[135]



[135] FEI capitalized overhead rate is proposed to change from 12 percent to 16 percent in 2020; this is reflected in the graph.

Figure C2-2: FBC Actual Net O&M in Real Dollars from 2013 to 2019 Base (2019 B)[136]



The O&M per customer funding presented on a Net O&M per customer basis in the above two tables provides a broader and complete perspective, taking into consideration that some of the O&M funding is related to the support of capital activities as described earlier.

As shown in the above tables, both FEI's and FBC's 2019 Base O&M reflect the permanent savings achieved in the Current PBR Plans. This Base O&M, when indexed as proposed, should be sufficient for FEI and FBC to maintain safe and reliable service while encouraging the Utilities to do more with what they have over the term of the Proposed MRPs.

[136] FBC capitalized overhead rate changed from 20 percent to 15 percent of Gross O&M in 2014.

3. CAPITAL FORECAST

3.1 *INTRODUCTION*

The Companies' capital expenditures involve projects of many types and sizes that are required to meet increasing requirements to maintain the safety, reliability and integrity of the gas and electric facilities used to provide service to existing and new customers, respond to the information needs and inquiries of customers, and to provide the information and systems necessary to support the business.

This section discusses the capital expenditures of FortisBC[137] during the Current PBR Plans, forecasts of capital expenditures over the 2020-2024 period, and the proposed formula for FEI's Growth capital. A discussion of anticipated Major Projects is also provided in Sections C3.3.3 and 3.4.2 below.

3.2 *CAPITAL PLANNING PROCESS*

FortisBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan is built to contain a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change and the plan must be capable of adapting. This plan flexibility allows FortisBC to manage and execute normal levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan.

FortisBC has been pursuing the development of a common asset management strategy across both the Gas and Electric divisions with the objective of continuing to improve upon maintenance and capital investment decisions, planning, and execution. These enhancements will help to demonstrate how FortisBC's decisions mitigate risks, improve performance and reduce non-essential costs.

The first step in the asset management strategy development was a high-level review of asset management competencies and practices compared to established industry practices derived from the international PAS55[138] standard. This was undertaken with the objective of identifying opportunities for improvement. The following four key principles were derived from this process:

1. Consistent and defendable decisions - Asset management decisions are made using consistent and objective processes across all asset classes.

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[137] Excluding Cost of Removal, Capitalized Overhead and Allowance for Funds Used During Construction (AFUDC) which will be forecast or calculated annually utilizing approved rates where applicable.

[138] BSI PAS 55: 2008 is the British Standards Institution's Publicly Available Specification for the optimized management of physical assets. PAS 55 is an internationally recognized specification defining good asset management practices.

2. Optimized decisions - Decisions are supported by the best data available, improving the ability of FortisBC to effectively balance decisions on safety, reliability and cost.
3. High accountability and ownership over assets – Employees are accountable and are engaged in their role in delivering safe, cost effective, and reliable services to ratepayers. Employees take on their day-to-day responsibilities like "owners" of the assets they are responsible for.
4. Integrated partnership model – The asset management planning department works closely with other departments and stakeholders to develop robust and achievable plans which balance sustainable system needs and regional priorities.

Since 2012, FortisBC has taken several steps to deliver on these principles, including:

- Placing asset management personnel within each region of the service territory to leverage local operational knowledge to inform decision making, while maintaining a consistent approach across all areas.
- Enhancing and standardizing the existing project planning methodology that moves investments through the stages of planning including need identification, scope definition, cost estimating, and execution.
- Improving the ability to generate and manage detailed multi-year capital plans to facilitate resource planning and deployment.

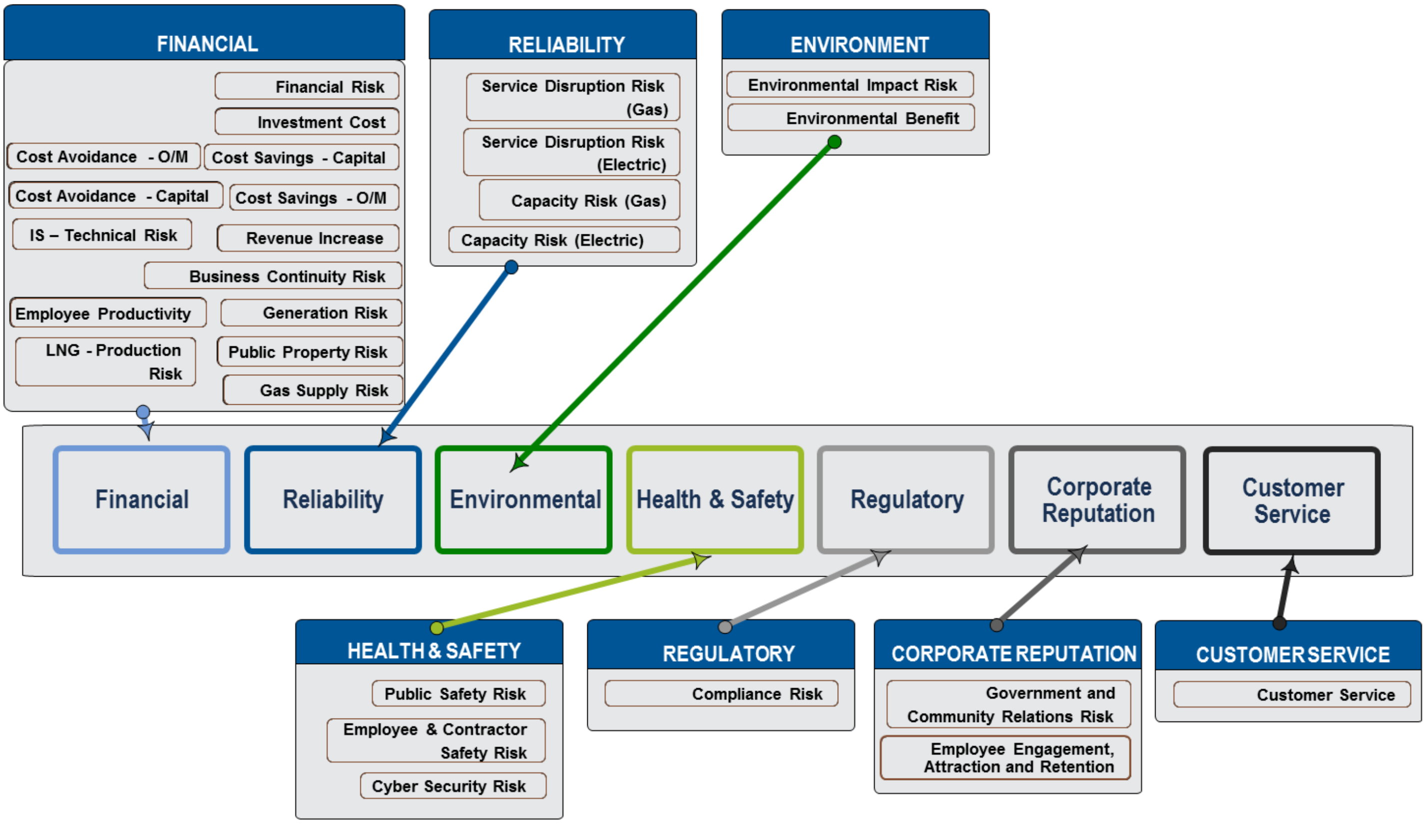
As introduced in FEI's Annual Review for 2018 Delivery Rates and FBC's Annual Review for 2019 Rates, FortisBC is implementing an Asset Investment Planning (AIP) process. The AIP process will help demonstrate decision-making processes to stakeholders and contribute to the goal of consistent decisions across asset classes.

In 2017, FortisBC implemented the first phase of an AIP tool[139]. The scope of implementation included the installation of Copperleaf C55 software and the development of processes and methodologies to support the consistent quantification of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types in the Gas Sustainment portfolio. The second phase of implementation is currently underway and includes Electric Sustainment, Information Systems, Fleet, and Facilities.

The foundation of the AIP tool is the value framework that is used to quantify the value of potential investments. The value framework is made up of seven overarching values that were derived from FortisBC's strategic objectives and core values. They are: financial, reliability, environmental, health & safety, regulatory, corporate reputation, and customer service. Under each value, there are measures that contribute to and impact each value. These measures, and which value they impact, are shown below in Figure C3-1 and described in greater detail below.

[139] Phase 1 applies to Gas asset management and to information systems. Gas general plant and Electric asset management will be part of future phases.

Figure C3-1: Asset Investment Planning Value Framework Overview



The AIP process and tool supports risk-informed decision-making in capital planning by quantitatively valuing investments through a value framework that is common to all asset classes. FortisBC actively manages the planning and execution of its capital plan to achieve the best value. For example:

- During the planning stages of capital projects, FortisBC bundles work that is at a common location or that is similar in nature to save on mobilization costs and material purchasing costs;
- Where possible, FortisBC develops standardized designs to save on material purchases, spare parts, and to reduce training needs and improve efficiency of the workforce;
- FortisBC uses a contracting strategy that reduces costs overall by leveraging a flexible workforce that is scalable and able to move to where the work is needed and when it is needed;
- FortisBC prioritizes projects and programs in such a manner as to allow for early engineering and design, procurement of materials and equipment, and comprehensive pre-job planning; and
- FortisBC works closely with municipalities in its operating territory to coordinate planned capital work to minimize project costs and disruption to the public, including in some

cases negotiating municipal operating agreements with many municipalities to bring cost certainty and improve working relationships.

Due to the non-repetitive nature of some capital work, efficiencies and savings achieved in one project are not necessarily applicable to the next project, and may be negated by cost pressures elsewhere. However, FortisBC has embedded productivity into the forecasts set out below by endeavoring to maintain capital spending increases at a level less than inflation over the course of the 2020-2024 term. Due to the timing and size of certain capital projects, fluctuations in capital spend from year to year are at times greater than inflation.

3.3 *FEI CAPITAL EXPENDITURE FORECAST*

Capital expenditures fall under two main categories: Major Projects and Regular capital[140].

Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a separate process, usually CPCN applications. FEI's Major Projects are discussed further in Section C3.3.3 below.

Regular capital expenditures include Growth, Sustainment and Other capital. Consistent with the Current PBR Plan, FEI's Regular capital expenditures are divided into the following categories:

- Growth capital, which consists of expenditures for the installation of new mains, services, meters, and distribution system improvements to support customer additions;
- Sustainment capital, which consists of expenditures for meter exchange programs, replacements and upgrades to the distribution and transmission systems related to safety, integrity and reliability, and expenditures for mains and service renewals and alterations; and
- Other capital, which consists of expenditures for information systems, equipment (including fleet vehicles) and facilities

System reinforcements to the distribution system required to maintain capacity to meet existing and forecasted loads have historically been included in the Sustainment capital category. For the Proposed MRP, FEI has categorized these capital expenditures in the Growth capital category. Similar to other Growth capital, these expenditures are driven by the addition of new customers onto the system. Transmission and intermediate pressure system improvements will remain in Sustainment capital, as will new stations. The relationship between these larger system upgrades and customer growth is often less direct, since a new station or pipeline looping project could lag a significant portion of the customer additions that drove the need.

[140] In addition, FEI has capital expenditures that are forecast each year during the Annual Review process and are discussed in Section C4.

The Regular capital additions are discussed below in terms of Growth (Section C3.3.1), and Sustainment and Other capital (Section C3.3.2).

3.3.1 FEI Growth Capital

3.3.1.1 Description of Growth Capital

FEI's Growth capital expenditures are necessary to attach new customers to the gas distribution system. These expenditures include the installation of new mains, services, meters and distribution system improvements to serve new customers.

The primary driver for Growth capital expenditures is gross customer additions, which is the number of new customers attaching to the gas distribution system with new mains and/or service installations and includes all customer segments. Gross customer additions for residential customers are in turn dependent on a number of factors including new housing starts, land development activity, and homeowners converting from other fuels to natural gas along with market capture. Gross customer additions for commercial and industrial customers are influenced by a number of factors including natural gas prices relative to other fuels, growth in specific economic sectors, and government policies and incentives.

When the capacity of the gas distribution system is insufficient to meet the needs of existing and new customers at the service location, system improvements are required to reinforce the distribution system to provide adequate inlet pressures to customers and ensure reliable service. Distribution system improvement costs have historically been included in Sustainment capital, but the driver for these costs is more closely tied to customer additions. FEI is accounting for these costs in Growth capital starting in 2020, and has restated the historical tables below to show them on that basis.

A description of the four categories of Growth capital follows.

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 (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.

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 new or conversion service header mains and 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.

While the MX test described above is used to determine if a contribution is required from customers wishing to connect to new mains, 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.

New Customer Meters

Meter expenditures include the cost to install new meter sets (meter, regulator, valve, piping, fittings) required to serve new customers.

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.

3.3.1.2 FEI Growth Capital during the Current PBR Plan

Growth capital expenditures both in total and on a per customer basis for mains, services, meters, distribution system improvements, and growth-related CIAC are summarized in Table C3-1 below.

Table C3-1: FEI Growth Capital Expenditures 2014-2018 ($000s)[141]

Growth Capital	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
New Customer Mains	8,420	13,752	12,823	16,467	24,494
New Customer Services	24,675	30,064	31,246	39,149	53,993
New Customer Meters	1,583	1,960	3,430	3,927	4,397
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)
Total Growth (Net)	33,360	48,694	47,947	60,339	84,787
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439
Growth Unit Cost (Net)	2,456	3,003	2,778	2,897	3,779

Subject to the MX test, FEI is obligated under the section 28 of the UCA to provide service if a supply line is near. Due to strong growth in gross customer additions, FEI was required to incur significant increases in Growth capital over the Current PBR Plan period in order to meet this mandate, as shown in Table C3-1 above. The strong growth in gross customer additions over the Current PBR Plan period is attributable to a number of factors, including a buoyant housing market, low commodity prices, and an increase in households converting from other fuels such as oil or propane to natural gas. FEI's efforts in proactively working with developers and customers to provide cost effective energy solutions that meet their needs contributed further to the strong growth in gross customer additions over term of the Current PBR Plan. The increase in gross customer additions, along with a higher cost per installation than was utilized in calculating the approved Base Growth capital amounts, were the primary drivers for the higher Growth capital expenditures under the unit cost approach in the Current PBR Plan.

Gross customer additions are counted as the number of new residential, commercial and industrial customers for which new service lines and meters have been installed in a given year. The growth in customer additions over the Current PBR Plan is shown in Table C3-2 below.

Table C3-2: FEI Gross Customer Additions 2014-2019

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	18,540

A summary of the factors that contributed to Growth capital variances during the Current PBR Plan term, including the impacts of customer growth, is included in Appendix B8-1.

3.3.1.3 Growth Capital for Proposed MRP

With this Application, FEI proposes to continue with a unit cost approach to determining Growth capital, but use a forecast of gross customer additions (instead of lagging 50 percent of actual service line additions), along with a re-based cost per customer amount, to enable better alignment between available capital and cost drivers while connecting new customers.

[141] Excluding pension and OPEB amounts which are added separately.

Consistent with the Current PBR Plan, FEI proposes to use a single unit cost measurement for all activities in Growth capital (mains, services, meters and distribution system improvements).

The proposed Growth capital formula is described in more detail in the next section, followed by further discussion of the proposed 2019 Base unit cost for Growth.

3.3.1.3.1 FEI GROWTH CAPITAL FORMULA

As in the Current PBR Plan, FEI is proposing a unit cost approach to determine Growth capital requirements for each year of the MRP term.

The inputs used for calculating Growth capital under the Proposed MRP include:

1. The 2019 Unit Cost Growth Capital Base which is discussed below;
2. A forecast of gross customer additions; and
3. The composite I-Factor value.

The following equation illustrates the formula applied to Growth capital (GC):

$$GC_t = UCGC_{t-1} \times (1 + I) \times GCA_t$$

Where: $GCA = Gross\ Customer\ Additions$
$UCGC = Unit\ Cost\ Growth\ Capital$
$I = Inflation\ Factor$
$t = Forecast\ year$

FEI proposes to use gross customer additions, instead of service line additions, in its Growth capital formula. FEI will forecast the gross customer additions for the test year in each Annual Review. In Section C1.1.4, FEI explains why the use of a forecast growth factor, rather than 50 percent lagged growth factor, as was approved for the Current PBR Plan term, is the appropriate approach and describes its proposed true-up process for growth factors to mitigate any forecast errors. The use of gross customer additions rather than service line additions is explained below.

A gross customer addition is a new service to a new customer or customers. A gross customer addition is not a "move-in", which is a change in the occupancy of a premise with an existing service, requiring the meter to be activated, but not typically requiring a capital expenditure[142].

The correlation between service line additions and the spending on mains, services, and system improvements is roughly equivalent to the correlation between gross customer additions and the spending on mains, services, and system improvements. Expenditures on meters, however, are more closely tied to gross customer additions, with a correlation of 0.94, than to service line additions, with a correlation of 0.88. This is due to ongoing changes in the housing market. FEI

[142] This differs from the growth in average customers, which is the net customer additions (gross customer additions less net of discontinued services).

is experiencing a higher proportion of multi-family additions. This change increases the number of customer attachments per service line addition which, as discussed in the Annual Review for FEI's 2018 and 2019 Delivery Rates filings, is increasing the cost per service line addition. The reason for this increase is discussed below.

In the case of a single detached home, there is generally one customer attachment per service line addition. In the case of a multi-family development, there can be upwards of 10 to 40 customers attaching to a single service line. The average customer attachment per service line addition ratio for 2016-2018 has been approximately 1.35, up from 1.2 in 2012.

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. A multi-family development requires a service line addition with larger pipe, additional fittings, and a larger riser, contributing to a higher service line addition cost.

Thus, to mitigate the unit cost variance experienced in the Current PBR Plan that was due to an upward trend in customer attachments per service line addition, FEI proposes to use gross customer additions instead of service line additions in its Growth capital formula.

3.3.1.3.2 PROPOSED GROWTH CAPITAL BASE UNIT COST

To set the base unit cost for 2020, the calculation starts with the average 2016-2018 actual unit costs as this amount is representative of FEI's level of capital investment required to provide service to new customers.

Two adjustments are then made to the 2016-2018 average actual[143] unit cost to arrive at the '2019 Base unit cost'. The adjustments are shown in lines 13 and 14 of Table C3-3 below. The goal of these adjustments is to determine the appropriate starting point for Growth capital unit costs for the Proposed MRP, incorporating known and measurable adjustments as appropriate. The two adjustments listed in the table are described in greater detail below.

143 Inflation adjusted to 2019 dollars.

Table C3-3: FEI Growth Capital Proposed Base Unit Cost

Line	Growth Capital ($000)	2016 Actual	2017 Actual	2018 Actual	Average	Reference
1	New Customer Mains	$ 12,823	$ 16,467	$ 24,494		
2	New Customer Services	31,246	39,149	53,993		
3	New Customer Meters	3,430	3,927	4,397		
4	System Improvements (DP)	2,953	3,566	4,433		
5	**Subtotal Growth (Gross)**	$ 50,452	$ 63,108	$ 87,316		Sum of Lines 1 through 4
6	CIAC	(2,505)	(2,770)	(2,529)		
7	**Total Growth (Net of CIAC)**	$ 47,947	$ 60,339	$ 84,787		Line 5 + Line 6
8	**Inflation Adjustment**	107.30%	104.86%	102.08%		
9	**Infl Adj Growth (Net)**	$ 51,447	$ 63,271	$ 86,551	$ 67,090	Line 7 x Line 8
10	**Gross Customer Additions**	17,261	20,825	22,439	20,175	
11	**Unit Cost Growth Capital $/CGA (Net of CIAC)**				$ 3,325	Line 9 / Line 10
12						
13	Construction Price Increase				$ 9,146	
14	Muster Kit & Material alloc impact				642	
15	**Incremental**				$ 9,787	Line 13 + Line 14
16	**Average Gross Customer Additions**				20,175	Line 10
17	**Unit Cost Growth Capital $/CGA Incremental**				$ 485	Line 15 / Line 16
18						
19	**Total Unit Cost Growth Capital $/CGA (Net of CIAC)**				$ 3,811	Line 11 + Line 17

<u>Construction Price Increases</u>

The average unit cost of Growth capital activities is impacted by a wide range of factors, including such factors as service size and length, site conditions, labour costs, municipal permitting, and system characteristics. Overall, FEI's analysis of historical volume mix incorporating updated pricing indicates an increase in the average construction price of approximately 13 percent ($9.146 million) in 2020 as compared to the 2016-2018 average in aggregate across all of the Growth capital activities. The main factors that make up the 13 percent increase are described below.

- **Contractor Price Increases:** FEI uses a combination of internal and contract resources to execute construction of mains and services. FEI's mains and services contracts were competitively bid in 2018, with the new terms, including pricing, coming into effect in 2019. As a result, FEI has agreements in place with two different mains and services contractors. The final unit costs negotiated with the two successful bidders are higher than the unit costs in place in the 2016-2018 period. In aggregate, and taking into consideration historical regional allocations of new services, the new contractor pricing represents a 9 percent increase to unit costs compared to historical.
- **Regional Growth Activity:** FEI experienced a significant increase in growth activities on Vancouver Island through the 2014-2018 period. In 2017 and 2018, approximately 31 percent of all new customer attachments were on Vancouver Island, compared to 25 percent in 2015 and 2016. This increase in activity has resulted in cost pressures from

the higher unit costs associated with installation in this region (due to its subsurface conditions and the corresponding municipal, pavement and traffic control requirements). Due to these unique construction challenges, each mains and services contractor has agreed upon pricing for each of the three main regions of FEI's service territory (Interior, Lower Mainland, Vancouver Island) to represent the different construction challenges present in each. The increase in contractor pricing in the new contract is 10 percent for the Interior and Lower Mainland and 13 percent for Vancouver Island. FEI is anticipating sustained growth on Vancouver Island that will increase the average unit cost due to the higher proportion of more costly Vancouver Island services. The net result is a further 1 percent increase to the overall unit cost.

- **Field Quality Assurance:** FEI is conducting increased field audits of Growth capital construction to continue to ensure quality requirements are met and to maintain documentation and records quality. These audits serve to verify that the quality of works remains high and to identify workmanship or procedures that require correction with the goal of avoiding defects in the system that are difficult to identify at a later date. This oversight also enables us to maintain the standards for and quality of records information provided by our contractors so that we are able to maintain accurate information about the installations we have. The net result is a further 2 percent increase to the overall unit cost.
- **Testing Installations:** FEI has also increased requirements for testing installations. This testing will identify material defects or installation errors before installations are placed into service. While the probability of the occurrence of such defects or errors is low, the consequence of failure should they not be identified is high. The net result is a further 1 percent increase to the overall unit cost.

Muster Kit & Material Allocation Impact

Muster kits and material allocations are the standard parts and fittings for routine work that are stocked in bulk at local musters and allocated out to completed jobs. The muster kit material charge for services was increased in 2017 to better reflect the actual cost for the materials used in an average service installation. Conversely, there was a reduction in the muster kit material charge for mains muster kits based on an evaluation of actual materials used in an average mains installation. The net impact of the changes is an increase of 1 percent ($642 thousand) on average Growth expenditures.

3.3.1.4 FEI Growth Capital Summary

The proposed mechanism and base unit cost for Growth capital is intended to allow FEI to make the capital investments necessary to add customers that request service as required by the UCA, while allowing a fair and balanced recovery mechanism for the costs necessary to ensure that service to existing customers is not eroded and the ability to sustain the existing gas system assets is not impacted. The proposed unit cost approach to Growth capital allows expenditures to vary based on customer growth while maintaining accountability for expenditures to attach new customers based on the unit cost.

3.3.2 Sustainment and Other Capital Overview

In this Application, FEI is seeking approval of the level of Sustainment and Other capital expenditures to be incorporated in rates over the term of the Proposed MRP. Due to its evolving operating environment and other uncertainties inherent in a five-year forecast, FEI proposes to review its forecast for 2023 and 2024 in its Annual Review for 2023 delivery rates. Should FEI deem necessary, it will file an updated forecast of the 2023-2024 expenditures in 2022 to account for any material changes to the forecast that occur over that time period and ask for approval of the changes.

Table C3-4 below summarizes the actual and projected Sustainment and Other capital expenditures from 2014 to 2019.

Table C3-4: FEI Sustainment and Other Capital Expenditures 2014-2019 ($000s)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Sustainment Capital	89,688	92,947	93,468	108,036	115,210	109,187
Other Capital	35,670	24,430	28,977	40,219	43,997	44,693
Total Capital	**125,358**	**117,377**	**122,445**	**148,255**	**159,207**	**153,880**

As Table C3-4 above illustrates, and as discussed during the Annual Reviews in the Current PBR Plan term, in years 2014-2016 FEI attempted to manage the pressures being experienced in Growth capital by reprioritizing some Sustainment and Other capital projects that were assessed as having some flexibility in timing to future years. However, as high volumes of customer additions continued to create pressures in Growth capital, it became untenable to continue to offset those costs. This resulted in higher spending levels in 2017-2019 for Sustainment and Other capital relative to 2014-2016. These higher levels are more consistent with the longer-term system requirements.

In 2017-2018 FEI exceeded the formula allowed amount and expects to do so again in 2019. The main reasons for the increased expenditures in these years are:

- Capital expenditures to catch up on an accumulation of work that had been re-prioritized from previous years of the PBR term.
- System improvements and new stations to support the added load generated by the higher than expected customer growth that took place during the PBR term.
- Increased in-line inspection activity to inspect transmission lines that were not previously capable of inspection, and the adoption of additional industry-standard technologies.

As a result of all of these factors, FEI's cumulative Sustainment and Other capital expenditures exceeded the formula amount by 15.9 percent over the PBR term. The contributing factors are discussed further in Appendix B8-1 FEI Capital Directives.

Table C3-5 below summarizes the 2020-2024 forecast expenditures for Sustainment and Other capital. Additional details of the forecast Sustainment and Other capital expenditures are provided in the following sections, under Section C3.3.2.1 FEI Sustainment Capital and Section C3.3.2.2 FEI Other Capital.

Table C3-5: FEI Sustainment and Other Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sustainment Capital	110,811	113,408	114,214	119,399	118,541	124,527
Other Capital	42,970	49,770	49,916	46,474	46,403	45,351
Total Capital	153,781	163,178	164,130	165,873	164,945	169,878

FortisBC has endeavored to maintain Sustainment and Other capital spending increases at a level less than inflation over the course of the 2020-2024 term. Due to the timing and size of certain capital projects, fluctuations in capital spend from year to year are at times greater than inflation. However, the cumulative capital expenditure forecast from 2020-2024 represents less than annual inflationary increases over that term.

3.3.2.1 FEI Sustainment Capital

The expenditures within Sustainment capital include gas system improvements to the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system. Sustainment capital includes expenditures for meter recall programs, replacements and upgrades to the distribution and transmission systems, and expenditures for mains and service renewals and alterations.

The actual and projected Sustainment capital expenditures from 2014-2019 are summarized in Table C3-6 below.

Table C3-6: FEI Sustainment Capital Expenditures 2014-2019 ($000s)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Customer Measurement	24,375	28,516	30,140	31,485	33,271	30,837
Transmission System Reliability & Integrity	22,043	30,409	31,738	37,596	39,095	42,301
Distribution System Reliability	13,634	18,346	14,213	18,232	17,686	13,088
Distribution System Integrity	29,635	15,676	17,378	20,722	25,158	22,960
Sustainment CIAC	(1,882)	(3,530)	(3,799)	(3,844)	(4,077)	(4,118)
Sustainment Capital – Total	**87,806**	**89,417**	**89,669**	**104,192**	**111,133**	**105,069**

Table C3-7 summarizes the Sustainment and Other capital expenditures required over the 2020-2024 term.

Table C3-7: FEI Sustainment Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Customer Measurement	31,864	30,559	31,328	31,781	32,461	32,979
Transmission System Reliability & Integrity	39,663	42,213	37,599	41,021	45,792	47,355
Distribution System Reliability	16,336	14,996	11,949	19,235	12,541	21,890
Distribution System Integrity	22,946	24,219	31,615	25,080	28,924	22,168
Sustainment CIAC	(4,013)	(3,902)	(3,902)	(3,902)	(3,902)	(3,902)
Sustainment Capital – Total	106,796	108,085	108,589	113,215	115,815	120,490

The forecast capital expenditures for each of the categories shown in the table above is described in more detail in the following sections, along with a description of larger projects (>$2 million) that are forecast within the 2020-2024 term. Cost estimates for projects that are planned for execution 2 or more years in the future are generally at a Class 4 (-30 percent to +50 percent) or Class 5 (-50 percent to +100 percent) level. Depending on the size and complexity of the project, a Class 3 estimate will be developed one to two years prior to execution.

3.3.2.1.1 CUSTOMER MEASUREMENT

Customer Measurement includes expenditures related to meter exchanges and meter set upgrades. Customer Measurement capital is further broken down into the four broad categories shown in the table below.

Details of the Customer Measurement capital expenditures from Table C3-7 above are summarized in Table C3-8 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table.

Table C3-8: FEI Customer Measurement Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Meter Materials	21,576	21,048	21,469	21,898	22,336	22,783
Residential Meter Alteration & Exchange	7,280	7,085	7,226	7,371	7,518	7,669
Small Commercial / Industrial Meter Alteration & Exchange	963	955	1,027	1,004	1,013	1,034
Large Commercial / Industrial Meter Alteration & Exchange	2,045	1,472	1,606	1,508	1,593	1,494
Customer Measurement - Total	**31,865**	**30,559**	**31,328**	**31,781**	**32,461**	**32,979**

Overall, Customer Measurement spending over the Proposed MRP is forecast to grow at less than one percent per year relative to the 2017-2019 average expenditure, and forecast expenditure levels are stable from year to year. For Customer Measurement capital, there are no projects over $2 million that are planned to be completed within the 2020-2024 term so no discussion of individual projects is provided.

3.3.2.1.2 TRANSMISSION SYSTEM RELIABILITY & INTEGRITY

The Transmission System Reliability & Integrity capital category includes activities related to the ongoing safe and reliable operation of the transmission system. The main areas of expenditure under this category include:

- Pipeline alterations to mitigate the threat of natural hazards, comply with codes and standards, and facilitate maintenance and inspections;
- Alterations to transmission facilities, including pressure control, compression, and LNG to ensure safe, reliable, and efficient operation; and
- Pipeline major inspections including inline inspections and marine crossing inspections.

Details of the Transmission System Integrity & Reliability capital expenditures from Table C3-7 above are summarized in Table C3-9 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table below.

Table C3-9: FEI Transmission System Reliability & Integrity Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Pipeline Alterations	16,503	20,736	15,250	16,484	17,702	16,918
Pipeline Capacity Improvements	3,943	-	-	-	-	-
Pipeline Station Alterations	4,632	4,494	5,639	5,536	6,426	5,996
Transmission System Telemetry Alterations	1,532	562	520	531	541	552
Compressor Station Alterations	2,362	3,582	4,874	4,132	3,728	3,798
Compressor Unit Overhauls	899	10	1,091	2,471	2,562	5,931
LNG Plant Alterations	4,551	5,006	5,806	7,144	6,579	7,322
Transmission System Cathodic Protection	292	441	450	459	468	362
Pipeline Inspection	4,869	7,382	3,937	3,759	7,775	6,476
Pipeline SRW Acquisition	80	-	32	507	11	-
Transmission System Reliability & Integrity – Total	**39,664**	**42,213**	**37,599**	**41,021**	**45,792**	**47,355**

Overall, Transmission System Reliability & Integrity spending over the term is growing less than four percent per year relative to the 2017-2019 average expenditure. In addition, most of the categories shown above have either lower or relatively stable spending forecast in comparison to the 2017 to 2019 average. Areas that have a significant variance are Pipeline Alterations, Pipeline Capacity Improvements, Compressor Unit Overhauls, LNG Plant Alterations, and Pipeline Inspection. Each of these areas is discussed further below.

- **Pipeline Alterations:** The relatively higher expenditure forecast in 2020 is attributable to a single larger (>$2 million) class location upgrade project that is discussed below, as well as a number of valve automation projects on the Coastal Transmission System. These valve automation projects are part of a multi-year program scheduled to be complete in 2022 that will improve FEI's ability to isolate the system for maintenance and emergencies. Spending levels in all other years are consistent with 2017-2019 average expenditure and are generally below inflationary increases.
- **Pipeline Capacity Improvements:** The 2017-2019 average expenditures include the Whistler IP pipeline capacity upgrade project. The forecast expenditures in this category are zero because there are no identified pipeline capacity improvements projects during the 2020-2024 term that fall within Sustainment capital.
- **Compressor Unit Overhauls:** Compressor Unit overhauls are scheduled based on manufacturer recommendations and the units' operating hours. Spending in this category was very low over the 2017-2019 period, with very few scheduled overhauls. Units 1, 2 & 3 at the V1 Compressor station are scheduled for major overhauls in the 2022-2024 period based on their current and projected operating hours.
- **LNG Plant Alterations:** With the addition of the Tilbury Expansion facility to the asset base, the increasing age of the Tilbury and Mt. Hayes facilities, as well as the increased usage of the LNG plants **both** as peak shaving resources and to provide LNG to FEI's transportation customers, additional investment in these assets is required to ensure ongoing compliance and reliability. Spending levels for LNG Plant Alterations are forecast to increase an average of 10 percent per year relative to the 2017-2019 average expenditure.
- **Pipeline Inspection:** Inline inspection programs are developed by FEI's System Integrity department based on the age, attributes, and condition of the pipeline. Spending levels for Pipeline Inspection are forecast to increase an average of 18 percent per year relative to the 2017-2019 average expenditure. The increased forecast expenditures are attributable to the following factors:
    - FEI has been increasing the length of inspectable pipeline in its system by removing obstructions;
    - FEI has adopted circumferential magnetic flux leakage technology for all in-line inspected pipelines; and

- FEI's reruns of geometry and standard magnetic flux leakage tools are now planned on a maximum 7-year interval.

Table C3-10 shows the anticipated spend profile of the projects greater than $2 million in this category during the 2020-2024 term.

Table C3-10: FEI Transmission System Reliability & Integrity Capital Expenditures on Projects Greater than $2 million for 2020-2024

	Portfolio	2020	2021	2022	2023	2024
Grand Forks to Trail 273 Pipeline Alteration	Pipeline Alterations	3,480	109			
V1 Compressor Unit 1, 2 & 3 Engine Overhaul and Emissions Reduction to 15 PPM*	Compressor Unit Overhauls	-	278	2,468	2,435	2,708
TIlbury LNG Air Cooler Upgrade	LNG Plant Alterations	-	-	-	3,184	-
5 Year Turnaround at Tilbury LNG Expansion	LNG Plant Alterations	-	-	612	1,873	-
Huntingdon to Nichol In Line Inspection	Pipeline Inspections	-	-	-	2,760	-

** parts per million*

Each of these projects is described further below.

- **Grand Forks to Trail 273 Pipeline Alteration:** The replacement of approximately 2.7 km of the Grand Forks to Trail pipeline is being undertaken to increase safety in response to population encroachments around the pipeline. The estimated cost of this project is approximately $4.1 million with the bulk of capital expenditures in 2020.
- **V1 Compressor Unit 1, 2 & 3 Engine Overhauls:** This project involves the regularly scheduled compressor overhaul of the engines at V1 Compressor Station. The overhaul will bring the units up to current emissions standards with a reduction from 25 PPM nitrogen oxide (NOx) emissions to 15 PPM NOx emissions to comply with the emission permit granted by Metro Vancouver. The estimated cost of this project is approximately $7.9 million. The overhauls are planned to be staged, starting with Unit 1 in 2022, Unit 2 in 2023, and Unit 3 in 2024.
- **Air Cooler Upgrade at Tilbury LNG:** The boil off fan at the Tilbury LNG facility is the original installed and is showing signs of corrosion. Repair or replacement options are currently being evaluated. The estimated cost of this project is approximately $3.2 million in 2023.
- **5 Year Turnaround at Tilbury LNG Expansion:** The pressure vessels at the Expanded Tilbury LNG Facility will undergo inspection as per the five-year inspection plan. The inspection will require drawing down the plant, depressurizing and isolating each pressure vessel, cleaning the vessels and performing inspections, and

recommissioning the plant. The plant is expected to be offline for one to two weeks. The estimated cost of this project is approximately $2.4 million with spending primarily in 2023.

- **Huntingdon to Nichol ILI:** The Huntingdon to Nichol pipeline will undergo in-line inspection using Magnetic Flux Leakage (MFL), Circumferential Magnetic Flux Leakage (CMFL) and Geometry tools as per the seven-year inspection program for this pipeline. The estimated cost of this project is approximately $2.8 million in 2023.

3.3.2.1.3 DISTRIBUTION SYSTEM RELIABILITY

Distribution System Reliability expenditures consist primarily of new pressure control stations or improvements to existing pressure control stations due to condition, load change, obsolescence and regulatory compliance. Also included in this category are alterations or improvements to distribution telemetry installations and distribution sectioning valves. As discussed in Section C3.3.3.1, Distribution System Improvements, which have historically been included in this category have been moved to Growth capital to better reflect the investment drivers, and any tables have been restated to reflect this.

Details of the Distribution System Reliability capital expenditures from Table C3-7 above are summarized in Table C3-11 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table.

Table C3-11: FEI Distribution System Reliability Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020 YEF	2021 YEF	2022 YEF	2023 YEF	2024 YEF
Distribution Stations Alterations	9,723	9,673	9,524	14,131	7,023	11,940
Distribution System Telemetry Alterations	1,130	1,356	1,207	1,486	2,779	2,173
Distribution System Capacity Alterations	4,549	489	64	2,412	1,331	5,508
Distribution Stations NEW	679	2,787	766	846	955	1,619
Revelstoke Propane Plant Alterations	248	162	312	274	311	650
Distribution Sectioning Valves	7	72	529	75	87	141
Total Distribution System Reliability	16,336	14,539	12,403	19,223	12,486	22,032

Distribution System Reliability spending has significant fluctuations from year to year due to the timing of specific projects in this category and to offset years of higher expenditure in other Sustainment capital categories. Overall, Distribution System Reliability spending over the 2020-2024 term is growing an average of 14 percent per year relative to the 2017-2019 average expenditure. Most of the categories shown above have relatively stable spending forecast in comparison the 2017 to 2019 average. Areas that have variances are Distribution Stations Alterations and Distribution System Capacity Alterations. Each of these areas is discussed further below.

- **Distribution Stations Alterations:** Expenditures in 2022 and 2024 are forecast to be higher than the other years of the term. The increased expenditures in these years are caused by capital portfolio optimization to offset expenditure fluctuations in other portfolios. Overall spending over the term is growing an average of 13 percent per year relative to the 2017-2019 average expenditure. The overall increase is due to the number of stations that require upgrades to address capacity shortfalls, obsolete equipment, and worker safety risks.

- **Distribution System Capacity Alterations:** For the 2020-2024 forecast, only IP system improvements are included in this category. These projects tend to be less frequent and higher cost than the DP system improvements. As such the expenditures in this category fluctuate greatly from year to year. The reason for the elevated forecast in 2022 and 2024 are large IP system improvements, discussed below, that are scheduled to be completed those years.

Table C3-12 shows the anticipated spend profile of the projects in this category greater than $2 million during the 2020-2024 term.

Table C3-12: FEI Distribution System Reliability Capital Expenditures on Project Greater than $2 Million 2020-2024 ($000s)

	Portfolio	2020	2021	2022	2023	2024
240 St & 102 Ave Station - Insufficient Capacity	Distribution Stations Alterations	260	2,184	78	-	-
SI - 1850m x 168 IPST McLeod	Distribution System Capacity Alterations	-	53	2,351	-	-
SI - 1300m x 323 IPST Riverside	Distribution System Capacity Alterations	-	-	-	51	3,536
Penticton Second Supply	Distribution Stations New	2,100	-	-	-	-

Each of these projects is described further below.

- **240 St. & 102 Ave. Station, Maple Ridge – Insufficient Capacity:** The station vault at 240 St. & 102 Ave. Station is approaching its first run capacity limit and requires upgrades to continue to serve customers in the area. Due to issues finding a suitable location for the new station, it is expected to cost $2.5 million in 2021.

- **SI – 1850m x 168 IPST McLeod, Chilliwack:** This system is experiencing significant load growth and is expected to require a system improvement in order to meet growing capacity demands. This upgrade involves installation of 1850m of 168 IPST from Yale Rd to Chilliwack Central Rd parallel to the existing 114mm DP main. The estimated cost of this project is approximately $2.4 million in 2022.

- **SI – 1300m x 323 IPST Riverside, Abbotsford:** This upgrade involves looping the existing 168mm IP with 1300m of 323mm STIP on Riverside Rd. from Hallert Rd. to Grace Rd. The estimated cost of this project is approximately $3.6 million in 2024.

- **Penticton Second Supply:** The City of Penticton and surrounding area are currently supplied through a single station. This project includes the installation of a second source of supply for the Penticton area to ensure reliable service to customers. The estimated cost of this project is approximately $4.3 million in 2020.

3.3.2.1.4 DISTRIBUTION SYSTEM INTEGRITY

Distribution System Integrity expenditures consist primarily of main and service alterations and replacements due to condition or at the request of third parties.

Details of the Distribution System Integrity capital expenditures from Table C3-7 above are summarized in Table C3-13 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table.

Table C3-132: FEI Distribution System Integrity Capital Expenditures 2020-2024 (000s)

	Average 2017-2019	2020	2021	2022	2023	2024
Main and service alterations	8,380	8,807	9,493	9,564	12,077	8,566
Main and service renewals	11,829	12,079	18,540	11,981	13,243	11,144
Service hazards mitigation	1,482	2,029	2,070	2,111	2,154	1,211
Distribution System Cathodic Protection	1,255	1,304	1,512	1,424	1,450	1,247
Distribution System Integrity - Total	**22,946**	**24,219**	**31,615**	**25,080**	**28,924**	**22,168**

Overall, Distribution System Integrity spending over the 2020-2024 term is growing an average of 1 percent per year relative to the 2017-2019 average expenditure. Most of the categories shown above have either lower or relatively stable spending forecast in comparison the 2017 to 2019 average. Areas that have variances are Main and Service Alterations and Main and Service Renewals. Each of these areas is discussed further below.

- **Main and Service Alterations:** The increased forecast expenditure in 2023 is attributable to a proposed project to install a secondary supply to NW Kamloops by installing an IP pipeline across the North Thompson River from Rayleigh to Westsyde. This would include a district station on the west side of the river. The estimated cost of this project is approximately $3.9 million in 2023.
- **Main and Service Renewals:** This category is an ongoing program to proactively replace aging distribution mains based on their condition and rate of leaks. Each year numerous main renewals are completed across the province. Due to the short planning horizon and the availability of external contractors to execute this work, it is well suited to scale up and down from year to year to accommodate other work. The fluctuations that are reflected in the forecast in this category are a function of capital plan optimization to accommodate larger, more valuable work in other categories. Overall, the forecast

expenditures in this category are higher as compared to the 2017-2019 average to ensure that the rate of main replacement is high enough to address areas where recurring leaks or mains in poor condition are identified.

For Distribution System Integrity capital, the secondary supply to NW Kamloops described in the discussion above on Main and Service Alterations is the only project over $2 million that is planned to be completed within the 2020-2024 term in these categories so no further discussion of individual projects is provided.

3.3.2.1.5 FEI CONTRIBUTIONS IN AID OF CONSTRUCTION

The recoveries in this category are forecast based on the anticipated receivable work for third party alterations and historical levels of receivable work for Transmission crossing replacements and identified recoverable projects. The forecasts reflect an anticipated stable level of contributions compared to recent years.

Table C3-14: FEI Sustainment CIAC 2014-2019 ($000's)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Sustainment CIAC	($1,882)	($3,530)	($3,799)	($3,844)	($4,077)	($4,118)

Table C3-15: FEI Sustainment CIAC 2020-2024 ($000's)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sustainment CIAC	($4,013)	($3,902)	($3,902)	($3,902)	($3,902)	($3,902)

3.3.2.2 FEI Other Capital

Other capital is further broken down into Equipment, Facilities and IS expenditures.

Equipment expenditures include costs associated with specialized tools and equipment, fleet vehicles and radio system upgrades. Facilities expenditures include costs associated with the acquisition or leasing of land, facilities including musters and office buildings, and facilities equipment. IS expenditures include costs associated with information systems hardware, infrastructure and software requirements.

The actual and projected Other capital expenditures from 2014-2019 are summarized in Table C3-16 below.

Table C3-16: FEI Other Capital Expenditures 2014-2019 ($000's)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Equipment	8,242	7,319	7,706	12,611	15,990	13,156
Facilities	4,062	2,473	3,632	5,023	5,254	5,020
Information Systems	23,366	14,639	17,638	22,585	22,753	26,517
Total Other Capital	35,670	24,430	28,977	40,219	43,997	44,693

Table C3-17 summarizes the forecast Other capital expenditures required over the 2020-2024 term.

Table C3-17: FEI Other Capital Expenditures 2020-2024 ($000's)

	Average 2017-2019P	2020	2021	2022	2023	2024
Equipment	13,919	15,106	13,378	12,288	12,100	12,110
Facilities	5,099	6,356	7,977	5,760	6,803	5,636
Information Systems	23,952	28,308	28,561	28,426	27,500	27,605
Total Other Capital	42,970	49,770	49,916	46,474	46,403	45,351

3.3.2.2.1 FEI EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles and equipment, telecommunication infrastructure, specialized tools and equipment and radio system upgrades. Expenditures for the equipment category are driven by obsolescence, excessive wear and regulatory compliance.

Details of the Equipment capital expenditures from Table C3-17 above are summarized in Table C3-18 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table.

Table C3-18: FEI Equipment Capital Expenditures 2020-2024 ($000's)

Equipment	Average 2017-2019P	2020	2021	2022	2023	2024
Tools and Equipment	2,565	4,450	3,300	3,300	3,300	3,300
Fleet Services	8,737	8,160	7,710	6,800	6,710	6,720
Measurement Services	412	503	505	505	507	507
Radio Communications	1,874	1,580	1,450	1,350	1,250	1,250
Supply Chain	332	413	413	333	333	333
Total Equipment Capital	13,919	15,106	13,378	12,288	12,100	12,110

Overall, Equipment spending over the term is declining approximately 3 percent per year relative to the 2017-2019 average expenditure, with the exception of 2020 that shows a 9 percent increase. Most of the categories shown above have either lower or relatively stable spending forecast in comparison the 2017 to 2019 average. Areas that have a variance are Tools and Equipment and Fleet Services. Each of these areas is discussed further below.

- **Tools and Equipment:** The increased expenditure in Tools and Equipment is driven by the introduction of a five-year modified tools replacement program costing approximately $1.2 million per year. Operations uses a variety of tools to operate and maintain the distribution and transmission systems. Many of the tools were designed and fabricated, or modified by the FEI machine shop and lack appropriate engineering documentation. The additional funding is to eliminate modified tools or ensure appropriate engineering documentation is available for all tools, components and sub-components that are used for pressure control or are pressure bearing.

- **Fleet Services:** Expenditures have been higher in recent years because of changes in headcount associated with new crews in the province, and because of reprioritization of vehicle purchases from earlier years of the Current PBR Plan as discussed above. As such, Fleet replacement costs are lower and trending downward over 2020-2024 period compared to the 2017-2019 average expenditure.

3.3.2.2.2 FEI FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and facilities furniture and equipment. 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 internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

For 2020 to 2024, the anticipated spending in the Facilities category is fairly consistent with historical Facilities spending, which fluctuates from year to year from approximately $5.6 million to $7.9 million based on the cyclical nature of the building assets' lives and condition.

Facilities will continue to support replacement and upgrade programs of HVAC, mechanical, electrical, security, building envelope, building finishes and office furniture and equipment as the assets reach the end of its service life. The increased capital expenditures for 2020, 2021 and 2023 are for larger projects to address muster replacements (as either the asset is near end of life or migrating from leased to own due to real estate lease market issues) and large roof replacements for the Coastal Facilities group of buildings (as the roofs are nearing the end of life).

3.3.2.2.3 FEI INFORMATION SYSTEMS CAPITAL

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 Management 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.

In situations where the utility is implementing infrastructure and/or applications that will benefit both gas and electric customers FEI has established a shared asset framework. The framework provides for equitable distribution of costs for assets that have a shared use and benefit from combined ownership. The allocation of asset ownership is defined through licensing and separate requisitioning for components based on usage of the shared asset by the respective organizations.

Details of the IS capital expenditures from Table C3-17 above are summarized in Table C3-19 below. Please refer to Appendix B8-2 for a description of the capital that is included in each of the categories shown in the table.

Table C3-19: FEI IS Capital Expenditures 2020-2024 ($000s)

IS	Average 2017-2019P	2020	2021	2022	2023	2024
Information Systems Sustainment	12,268	11,218	11,811	11,676	10,750	10,855
Application Enhancements	1,999	2,850	2,850	2,850	2,850	2,850
Cybersecurity	1,217	2,900	3,100	3,100	3,100	3,100
Business Technology Applications	8,467	10,800	10,800	10,800	10,800	10,800
Total	23,952	27,768	28,561	28,426	27,500	27,605

The annual average IS spending for all of the categories shown in the table was almost $24 million for 2017 to 2019. Overall, IS expenditures are growing approximately 3 percent per year relative to the 2017-2019 average expenditure. There has been a continued increase in spending from 2017 to 2019 in all categories except Sustainment. Each of the four categories is discussed below.

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, local area network (LAN) and wide area network (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.

Application Enhancements:

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. The increased implementation of business tools over the last 5 years has increased the amount of applications requiring enhancements.

Cyber security:

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 required the business to engage in testing, custom configuration and code updates to deploy the updates. Tools to monitor and counteract these threats have to be evaluated and implemented to maintain an acceptable level of cyber security.

Business Technology Applications:

This category includes capital funding for initiatives that impact the way business is conducted and that support business units' 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.

Expenditures in this category show an initial increase in 2020, followed by stable spending thereafter. The increased expenditures forecast for 2020 to 2024 are for projects required to improve business processes and productivity, retain and attract customers, continue to meet compliance requirements, retain and attract new employees, replace outdated applications, and increase the use of data analytics. The prioritization and selection of projects for each year are completed by the fall of the year previous. This process is designed to ensure that projects with higher value will be considered first when allocating finite resources.

In general, the pace of change in the IS portfolio is greater than what FEI has experienced in the past. There is an expectation of and increased sophistication from customers and employees on the types of services and capabilities provided that is dependent on technology. In addition, the rapid pace of change of technology necessitates more frequent replacement of systems due to obsolescence, loss of technical support, or risk of cyber threats, or to leverage the benefits of new functionality. Prudent investments in technology are not only key to realizing efficiencies in the day-to-day operation of the utility, but also to advancing innovation in the way we interact with customers and the energy services that we provide.

3.3.2.3 Sustainment and Other Capital Summary

FEI is forecasting consistent spend levels over the course of the 2020-2024 term. Due to the timing and size of certain capital projects, fluctuations in capital spend from year to year are at times greater than inflation. However, the cumulative capital expenditure forecast from 2020-2024 represents less than annual inflationary increases over that term.

FEI actively manages the capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall Sustainment and Other capital forecast included in rates are subject to change, and FEI may identify different projects and programs that need to be added over the term of the Proposed MRP.

There are also a number of external factors that could lead to increases or decreases in the actual expenditures over the term. Significant pressures include:

- Internal and external labour costs;

- Currency exchange rates;
- Renegotiation of municipal operating agreements;
- Permitting costs; and
- Trade restrictions and tariffs.

Of these, the first two have been experienced in the past, but the last three are new or changing factors that could put pressure on FEI's capital costs, as discussed in Section B1. FEI proposes to review its forecast for 2023 and 2024 in its Annual Review for 2023 delivery rates. Should FEI deem necessary, it will file an updated forecast of the 2023-2024 expenditures in 2022 to account for any material changes to the forecast that occur over that time period and ask for approval of the changes.

3.3.3 FEI Major Projects

As noted above, Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a separate CPCN or other application. Thus, Major Projects are generally works that cost greater than $15 million for FEI. Below, FEI provides examples of the Major Project applications that may arise during the course of the 2020-2024 MRP Application.

- FEI Inland Gas Upgrades;
- FEI Transmission Integrity Management Capability;
- FEI Okanagan Capacity Upgrade;
- FEI Pattullo Bridge Gas Line Replacement;
- FEI Southern Crossing Class Location Upgrades;
- FEI Sun Peaks Gas Conversion;
- FEI Sunshine Coast Capacity Upgrade; and
- FEI Advanced Metering Infrastructure.

Each of these projects is described in more detail below.

3.3.3.1 FEI Inland Gas Upgrades

Forecast Construction Timeline: 2020-2024

This project comprises upgrades to 29 gas transmission pipelines of NPS 6 and larger that do not currently have ILI capability in order to meet FEI's objective of further reducing the external corrosion hazard and/or limiting potential consequences associated with time-dependent threats. Upgrades are primarily comprised of retrofits to enable ILI (≈ 360 km), although other alternatives are being recommended due to lower impact and/or reduced cost. Pressure regulation is being recommended for ≈ 55 km of line, with pipe replacement recommended for ≈ 8 km of line.

This project has been filed with the BCUC as a CPCN.

3.3.3.2 FEI Transmission Integrity Management Capability

Forecast Construction Timeline: 2021-2024

FEI has detected instances of cracking on its system. Due to the potential consequences of failure associated with its transmission pipeline system, FEI believes that the hazard of cracking requires managing through higher-confidence methods (i.e., ILI). A common response to integrity concerns on pipelines (both operator-imposed and regulator-imposed) is a 20% pressure reduction (equivalent to a 1.25 pressure test).

This project comprises upgrades to gas transmission pipelines to enable their inspection with crack-detection (EMAT) technology. Upgrades will deliver:

- Capability to run crack-detection ILI tools
- Capability to operate pipelines with pressure reductions to enable appropriate response to integrity concerns without loss of customer supply

In order to establish a repeatable process for the ongoing identification of appropriate safety and reliability mitigation projects for an aging transmission system, this project will also comprise the establishment of quantitative risk capabilities for transmission pipelines (people, process, tools, data).

3.3.3.3 FEI Okanagan Capacity Upgrade

Forecast Construction Timeline: Phased over 2022-2031

FEI forecasts that by 2022 inlet pressure to Kelowna Gate Station will drop below 2400 kPa and this will result in a shortage of supply to the Kelowna distribution system and the IP pipeline serving West Kelowna.

Several alternatives are currently being reviewed and estimated by FEI to evaluate the best alternative in consideration of the Okanagan capacity needs as well as FEI's long-term system integrity objectives. Although this analysis is not yet complete, the most likely option at this time is a phased approach that includes:

- replacing several sections of pipeline to allow the operating pressure to be increased,
- increased pipeline capacity on two laterals, and
- increased compression horse power at Kitchener.

3.3.3.4 FEI Pattullo Bridge Gas Line Replacement

Forecast Construction Timeline: 2020-2021

Ministry of Transportation and Infrastructure (MOTI) is planning the replacement of the Pattullo Bridge. Construction is scheduled to begin in the summer of 2019 with the new bridge to open in 2023. FEI has a 700 kPa pipeline on the existing bridge that provides critical supply to New Westminster. MOTI has requested that the pipeline be removed from the existing bridge by 2021. The crossing needs to be replaced to ensure continued supply to New Westminster.

MOTI has rejected a proposal to install a pipeline on the new bridge. Other options are still being evaluated, but the favored solution at this time is a new NP12 transmission pressure pipeline HDD crossing under the Fraser River to supply gas to a new TP-DP Gate Station in New Westminster.

3.3.3.5 FEI Southern Crossing Class Location Upgrades

Forecast Construction Timeline: 2021-2022

Pipeline upgrades are required on the Southern Crossing 610 pipeline due to the encroachment of structures around the pipeline. The upgrades are required on the Yahk to Rossland and the Rossland to Oliver segments of the pipeline where the class location has increased to Class 3 or to Class 2. The upgrades consist of replacing 11 segments of pipeline (approx. 8 km) with thicker walled pipe and adding 7 new valves to reduce valve spacing to meet the design requirements of the new class location. Combining all of these segments into a single CPCN is proposed to improve efficiency by grouping the work together, as well as to coordinate and minimize downtime on the Southern Crossing pipeline.

3.3.3.6 FEI Sun Peaks Conversion

Forecast Construction Timeline: 2020-2021

This project involves the conversion of the Sun Peaks community from propane to natural gas. FEI is currently evaluating alternatives including a connection to the natural gas system.

3.3.3.7 FEI Sunshine Coast Capacity Upgrade

Forecast Construction Timeline: 2020 - 2022

The project involves improving the gas supply to the tail end of the Sunshine Coast intermediate pressure system, which supplies natural gas from Sechelt south to Gibsons. System Capacity Planning forecasts that during the winter of 2019/20 there will be a shortfall in capacity in the existing intermediate pressure system, affecting the available supply through the Gibsons Gate Station. A short-term solution will be implemented to prevent customer outages. For a long-term solution, a number of options are being considered including some that will provide an alternate supply to the system.

3.3.3.8 FEI Advanced Metering Infrastructure (AMI)

Forecast Construction Timeline: 2020-2025

This project will provide FEI customers with customer service, sustainability, resilience, and safety benefits. The scope of work includes the replacement of existing mechanical diaphragm meters with new electronic metering that includes integrated shut-off valves and two-way communicating radios. Gas customers in British Columbia will be able to access detailed consumption information, allowing them to better manage their energy consumption. In the event of major infrastructure damage, as can occur during earthquakes or fires for example, the ability to remotely shut-off gas service to a building will provide an additional measure of safety for FEI customers. Should gas supply be disrupted for any reason, the remote shut-off valves will help ensure that system pressure is maintained, significantly reducing the amount of time required to re-establish service when supply is restored.

3.4 *FBC CAPITAL EXPENDITURE FORECAST*

FBC's capital expenditures fall under two main categories: Regular capital and Major Project capital expenditures.

Regular capital expenditures includes Growth, Sustainment and Other capital. Regular capital expenditures are explained further in Section 3.4.1 below.

Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a separate process, usually CPCN applications. FBC's Major Projects are discussed further in Section C3.4.2 below.

In this Application, FBC is seeking approval of the level of Growth, Sustainment and Other Regular capital expenditures to be incorporated in rates over the term of the Proposed MRP. In response to the evolving operating environment and other uncertainties inherent in a 5-year forecast, FBC proposes to review its forecast in its Annual Review for 2022 rates. Should FBC deem it necessary, it will file an updated forecast of the 2023-2024 expenditures in 2022 to account for any material changes to the forecast that occur over that time period and ask for approval of the changes.

3.4.1 FBC Regular Capital

FBC's Regular capital expenditures are divided into the following categories:

- Growth capital, which consists of expenditures for infrastructure upgrades required to meet demand for new customers and/or load growth;
- Sustainment capital, which consists of expenditures for system reinforcements, asset replacements and upgrades to the generation, transmission and distribution assets, to ensure safety, integrity and reliability; and

- Other capital, which consists of expenditures for information systems, equipment and facilities.

The majority of FBC's Regular capital expenditures is comprised of numerous ongoing programs that are required to meet load growth, maintain existing utility infrastructure and to support FBC's capital and operating activities. In the sections below, projects forecast to exceed $1 million are individually identified.

Table C3-20 below provides FBC's capital expenditures for the term of the Current PBR Plan. The 2014 through 2018 expenditures are actual; the 2019 expenditures are projected.

Table C3-20: FBC Actual and Projected Regular Capital Expenditures, 2014-2019 ($000s)

	2014	2015	2016	2017	2018	2019P
Growth Capital	$ 18,195	$ 21,267	$ 15,456	$ 22,333	$ 24,003	$ 17,519
Sustainment Capital	41,158	27,301	25,645	29,367	28,616	33,227
Other Capital	8,408	8,183	9,307	13,882	11,942	15,225
Total Regular Capital	67,761	56,752	50,408	65,582	64,561	65,971

Table C3-21 below summarizes 2020-2024 forecast expenditures for Regular capital for FBC. Details of the forecast capital expenditures are provided in Sections C3.4.1.1 to C3.4.1.5 of the Application.

Table C3-21: FBC Regular Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Growth Capital	$ 21,285	$ 27,029	$ 23,042	$ 24,339	$ 26,283	$ 23,170
Sustainment Capital	30,403	50,743	50,098	43,110	44,657	53,901
Other Capital	13,683	15,752	14,712	14,756	15,281	15,134
Total Regular Capital	65,371	93,524	87,853	82,205	86,220	92,204

Growth, Sustainment and Other capital expenditures for 2020-2024 are forecast to be higher than 2017-2019 expenditures. The primary drivers for the increase in capital expenditures are increased requirements for system improvements to accommodate load growth, upgrades to aging generation assets to meet current codes and standards, and equipment replacements necessary to address condition, aging infrastructure and improve reliability. Regulatory requirements and the need to address cyber threats also contribute to an increase in capital expenditures in comparison to previous spending levels.

3.4.1.1 FBC Growth Capital

FBC's Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The average 2017-2019 and forecast Growth capital expenditures are summarized in Table C3-22 below.

Table C3-22: FBC Growth Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Transmission Growth	$ 1,572	$ 5,172	$ 2,063	$ 2,740	$ 5,195	$ 1,086
Distribution Growth	1,232	3,716	1,876	1,807	1,899	1,921
New Connects	18,481	18,141	19,104	19,792	19,188	20,163
Total	$ 21,285	$ 27,029	$ 23,042	$ 24,339	$ 26,283	$ 23,170

Growth capital expenditures in 2020-2024 are forecast to be higher on average than 2017 to 2019 expenditures. Electric system capacity additions are generally comprised of discrete projects sufficient in size to meet future load growth, as opposed to small incremental additions. FBC requires a number of such projects for both the transmission and distribution systems over the 2020-2024 timeframe, as described in the following sections.

Each of the three areas – Transmission Growth, Distribution Growth, and New Connects, is described further below.

3.4.1.1.1 TRANSMISSION GROWTH CAPITAL

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load, for adequate supply during periods of peak demand and adverse weather conditions. Annual expenditures are variable, as can be seen in Table C3-23 below.

Table C3-23: FBC Transmission Growth Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	$ 278	$ 4,633	$ -	$ -	$ -	$ -
Summerland Transformer Replacement	n/a	539	2,063	-	-	-
Beaver Park Substation Upgrade	n/a	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	n/a	-	-	-	-	1,086
Other Transmission Growth	1,295	-	-	-	-	-
Total	$ 1,572	$ 5,172	$ 2,063	$ 2,740	$ 5,195	$ 1,086

Projects over $1 million that are planned to be completed within the 2020-2024 term include:

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer is forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer will be installed at the Sexsmith substation. The estimated cost of this project is $5.4 million. FBC forecasts spending $0.8 million in 2019 and $4.6 million in 2020 with an expected in service date of 2020.
- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to new commercial development in Summerland, peak load at this wholesale delivery point is forecast to exceed 95 percent of the contract demand limit in 2021. Per the terms of the wholesale supply contract, FBC will need to

upgrade the capacity of the transformer in order to continue to provide reliable service. The estimated cost of this project is $2.6 million. FBC forecasts spending $0.5 million in 2020 and $2.1 million in 2021 with an estimated in service date of 2021.

- **Beaver Park Substation Upgrade:** This project is driven by capacity constraints and equipment condition. The area load for the Beaver Park substation near Trail is forecast to exceed the nameplate capacity of this single-transformer substation in winter 2021. The project includes the replacement of the existing transformer due to the condition of the tap changer, which can no longer be adequately maintained, and the installation of a second transformer and associated switchgear in order to support N-1 contingency planning criteria. The estimated cost of this project is $7.9 million with an in-service date of 2023. This in-service date is consistent with FBC's planning criteria, which permit loads to exceed nameplate rating by 25 percent during winter peak.
- **DG Bell Second Transformer Addition:** The 2018 distribution load forecast indicates that planning criteria will not be met for the Upper Mission area of Kelowna in summer 2025. FBC will install a second distribution transformer to increase the substation supply capacity, to maintain the current level of reliability and support N-1 contingency planning criteria. The estimated cost of this project is $5.4 million. FBC forecasts spending $1.1 million in 2024 and $4.3 million in 2025 with an estimated in-service date of 2025.

3.4.1.1.2 DISTRIBUTION GROWTH CAPITAL

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included. Table C3-24 below provides the 2017-2019 average and the 2020-2024 forecast for Distribution Growth capital expenditures.

Table C3-24: FBC Distribution Growth Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Small Growth Projects	$ 419	$ 1,040	$ 1,070	$ 1,102	$ 1,122	$ 1,137
Unplanned Growth Projects	813	707	805	704	777	784
DG Bell Feeder 4 Addition	n/a	1,970	-	-	-	-
Total	$ 1,232	$ 3,716	$ 1,876	$ 1,807	$ 1,899	$ 1,921

These projects include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades and conductor upgrades that are necessary due to load growth. The Small Growth Projects program consists of planned projects less than $0.5 million in size. The Unplanned Growth Projects program consists of unforeseen projects typically less than $0.2 million in size and the forecast expenditures are based on historical expenditures.

The following project is forecast to exceed $1 million:

- **DG Bell Feeder 4 Addition:** The addition of a fourth feeder is required to meet the significant residential customer growth occurring in the upper Mission area of Kelowna. The expected in-service date of this $2.0 million project is 2020.

3.4.1.1.3 NEW CONNECTS

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on historical expenditures adjusted for anomalous years and inflation.

3.4.1.2 FBC Sustainment Capital

The expenditures within Sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects.

Sustainment capital is further classified into five categories of expenditure, each of which is described in more detail in the following sections, along with a description of projects forecast to exceed $1 million that are expected to proceed within the 2020-2024 term. Table C3-25 below summarizes the average 2017-2019 actual and projected expenditures and forecast 2020-2024 expenditures for these categories of sustainment capital.

Table C3-25: FBC Sustainment Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Generation	$ 3,475	$ 6,697	$ 6,766	$ 6,309	$ 7,008	$ 6,514
Transmission Sustainment	4,778	8,353	6,387	5,698	7,951	7,591
Stations Sustainment	4,915	13,538	13,624	5,279	3,793	15,971
Distribution Sustainment	17,952	20,337	20,338	19,542	19,990	20,353
Telecommunications	2,516	1,818	2,983	6,280	5,915	3,472
Total	$ 33,636	$ 50,743	$ 50,098	$ 43,110	$ 44,657	$ 53,901

Each of these five categories is described further below.

3.4.1.2.1 GENERATION CAPITAL

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees.

FBC's Generation capital is grouped into four capital programs.

Table C3-26 below provides the 2017-2019 average and the 2020-2024 forecast expenditures for FBC's four Generation capital programs.

Table C3-26: FBC Generation Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Hydraulic Dam Structures	$ 1,329	$ 4,130	$ 3,726	$ 2,206	$ 1,955	$ 2,730
Generating Equipment	616	1,058	1,207	2,148	3,277	866
Generation Auxiliary Equipment	876	955	1,033	809	809	823
Buildings and Structures	653	554	800	1,146	966	2,095
Total	$ 3,475	$ 6,697	$ 6,766	$ 6,309	$ 7,008	$ 6,514

FBC anticipates higher expenditures for Generation capital compared to the previous three-year period. The main drivers for the increased expenditures in this category include: compliance with Dam Safety and Occupational Health and Safety (OHS) regulations, upgrades to equipment due to condition and obsolescence, and the deterioration of aged concrete structures and buildings that pose a risk to operations and personnel safety.

Hydraulic Dam Structures

The Hydraulic Dam Structures program includes capital projects that are related to the following Generation assets: concrete structures, water flow control equipment (gates and stop logs), superstructures, lifting equipment (hoists and gantries), and dam safety equipment. Table C3-27 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for hydraulic dam structures.

Table C3-27: FBC Hydraulic Dam Structures Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	$ 462	$ 685	$ 821	$ 979	$ 1,128	$ 1,019
LBO Spillway Gates Refurbishment	92	1,467	1,396	-	-	-
Other Gates Upgrades	283	481	100	414	241	545
Dam Safety Instrumentation	428	715	765	-	-	806
Guarding of Rotating Parts	6	194	324	458	295	287
Other Hydraulic Dam Structures Projects	58	588	320	355	291	73
Total	$ 1,329	$ 4,130	$ 3,726	$ 2,206	$ 1,955	$ 2,730

The following projects over $1 million are planned to be completed within the 2020-2024 term:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 and the cost for this project is to address the BC Dam Safety Regulation and deterioration of concrete structures. The deterioration of concrete structures creates employee safety hazards and operational issues and could potentially contribute to structural failures. If not addressed proactively, the deterioration will continue to accelerate resulting in increased expenditures in future years to address the issues. In 2018, a comprehensive third party engineering inspection of the plants identified locations that require resurfacing of deteriorated concrete, repair of waterway structures such as spillway piers, forebay piers, forebay walls, spillway walls, tailrace piers. The locations were assessed and prioritized using the REMR (Repair, Evaluation, Maintenance, and Rehabilitation) condition rating system developed by the US Army

Corps of Engineers. The estimated cost of this project is approximately $4.6 million over the period 2020-2024.

- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project involves the refurbishment of the two spillway gates installed at LBO. The costs for this project in 2020 and 2021 are required to rectify age-related condition issues, meet current regulations, and minimize the risks to public and employee safety. The estimated cost of this project is approximately $2.9 million with an estimated in service date of 2021.
- **Other Gates Upgrade Project:** This project includes the refurbishment and upgrade of the intake, spillway, tailrace gates, stoplogs and associated operating devices (gantry and hoist) installed at Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan. The cost for this project in 2020-2024 is to rectify age-related condition issues, meet current regulations, and minimize the risks to public and employee safety. The estimated cost of this project is approximately $1.8 million over the period 2020-2024.
- **Dam Safety instrumentation project:** The cost for this project in 2020-2024 is to address the requirement in section 19 (1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. The estimated cost of this project is approximately $2.3 million for the period 2020-2024.
- **Guarding of Rotating Parts Project:** All of FBC's plants were constructed before current OHS requirements were developed and, as such, most of the equipment with rotating and moving parts installed in the plants (in the powerhouse and on the dam structure) does not contain guards and most of the covers installed do not have the strength required to meet OHS requirements. Thecost for this project in 2020-2024 is to address the OHS requirements under WorkSafe BC legislation[144]. The estimated cost of this project is approximately $1.6 million over the period 2020-2024.

Generating Equipment

The Generating Equipment program includes capital projects that are related to the following generation assets: turbine, generator, governor system, excitation system, unit control system, lubrication system, cooling water system, generator switchgear. Table C3-28 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for generating equipment. The forecast projects are required to address generation equipment that has reached the end of service life.

[144] This project is required to achieve compliance with OHS 12.16 and OHS 12.3 rules related to guarding of rotating parts and OHS 4.59 related to the load rating of hatches, plates and covers.

Table C3-28: FBC Generating Equipment Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
UBO Unit 6 Turbine Runner Replacement	$ -	$ -	$ 35	$ 582	$ 2,035	$ -
Generator Excitation and Control Systems	-	-	67	556	556	-
Generator Thrust Bearing Cooling System	100	247	271	295	198	198
Other Generating Equipment Projects	517	811	834	716	488	669
Total	$ 616	$ 1,058	$ 1,207	$ 2,148	$ 3,277	$ 866

The following projects over $1 million are planned to be completed within the 2020-2024 term:

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. The Unit 6 turbine runner is original and will be approximately 88 years old at its proposed date for replacement in 2023. The runner was designed based on manual calculations and was made of cast steel, with an expected life of 75 years based on industry experience. The estimated cost of this project is approximately $2.7 million with an expected in service date of 2023.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 due to obsolescence, and the replacement of two-unit control systems and one plant control system, which have reached the end of their service life. The estimated cost of this project is approximately $1.2 million over the period 2021-2024.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project includes the replacement or upgrade of the oil cooling system installed on the generator thrust bearing of FBC's generator equipment and installation of isolating valves on the water supply system. FBC has 15 thrust bearings and all are original between 78 to 110 years of age. The estimated cost of this project is $1.2 million over the period 2020-2024.

Generation Auxiliary Equipment

The Generation Auxiliary Equipment program includes capital projects that are related to the following generation assets: station service system, cranes, elevators, sump pumps, dewatering and drainage system, heating and cooling system, compressed air system, communication and network systems, and security systems. Table C3-29 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for generation auxiliary equipment. The forecast projects are required to address generation auxiliary equipment that is at the end of its service life.

Table C3-29: FBC Generation Auxiliary Equipment Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Dewatering and Drainage Systems	$ 60	$ 116	$ 349	$ 349	$ 349	$ 349
Station Service Upgrade	64	333	495	286	286	300
Other Auxiliary Equipment Projects	753	506	189	175	175	175
Total	$ 876	$ 955	$ 1,033	$ 809	$ 809	$ 823

The following projects over $1 million are planned to be completed within the 2020-2024 term:

- **Dewatering and drainage systems rehabilitation project:** This project is a continuation of the program started in 2011 and involves the rehabilitation of pipes, valves and other components of the dewatering and drainage systems, which are original to the plants, having service lives of over 75 years. The systems have begun to fail due to their service age, corrosion, wear and tear. The estimated cost of this project is $1.5 million over the period 2020-2024.
- **Station service upgrade project:** This project includes upgrading the protection system of FBC's station service system protection and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements projects. The estimated cost of this project is $1.7 million over the period 2020-2024.

Buildings and Structures

The buildings and structures category includes capital projects that are related to the following Generation assets: buildings and building components (walls, doors, windows, roofs, etc.) heating and ventilation systems, fences, access roads. Table C3-30 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for generation buildings and structures.

Table C3-30: FBC Generation Buildings and Structures Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
COR Annex Building Replacement	$ 76	$ -	$ -	$ -	$ 198	$ 1,606
Floor Covers Replacement	223	349	116	116	349	116
Roof Replacement	-	62	291	233	233	233
Other Buildings and Structures Projects	354	143	393	797	187	140
Total	$ 653	$ 554	$ 800	$ 1,146	$ 966	$ 2,095

The following project over $1 million is planned to be completed within the 2020-2024 term:

- **Corra Linn Annex Building Replacement Project:** The incremental cost of this project in 2023 to 2024 is to address deterioration of concrete structures and buildings that pose a risk to operations and personnel safety. The estimated cost of this project is $1.8 million with a planned in-service date of 2024.

3.4.1.2.2 TRANSMISSION SUSTAINMENT CAPITAL

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers. Future year sustainment budgets are developed based on condition assessments.

Transmission sustainment capital is further broken down into four programs, and the 2017-2019 average and the 2020-2024 forecast capital expenditures are provided in Table C3-31 below.

Table C3-31: FBC Transmission Sustainment Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Transmission Line Condition Assessment	$ 553	$ 740	$ 426	$ 632	$ 502	$ 594
Transmission Line Rehabilitation	3,186	6,013	4,332	3,354	5,819	5,290
Tranmission Urgent Repairs	573	501	525	591	502	570
Transmission Rights of Way	466	1,099	1,104	1,121	1,128	1,136
Total	$ 4,778	$ 8,353	$ 6,387	$ 5,698	$ 7,951	$ 7,591

Transmission Line Condition Assessment

The Transmission Line Condition Assessment program is based on an eight-year cycle of inspecting and testing all FBC transmission line facilities. The program consists of a pole test and treat component and an above ground visual condition inspection. The test and treat component of the program is aimed at the section of pole at the ground level and below. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying, apparatus and grounding) attached to the pole. If an issue is detected during the condition assessment the deficiency is documented and corrected under the following year's transmission rehabilitation budget. The program is managed in an eight-year cycle to levelize both the budget and the resources required. Expenditures vary from year to year based on the length of the lines and number of structures in each line.

Transmission Line Rehabilitation

The specific rehabilitation projects for various transmission facilities involve expenditures for stubbing poles, replacing poles, cross-arms, guy wires, as well as correcting other defects identified in previous years' assessments. Specific planned expenditures for each transmission line are identified after completion of the condition assessment in the previous year. Table C3-32 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for Transmission Line Rehabilitation projects.

Table C3-32: FBC Transmission Line Rehabilitation Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
30 Line Rehabilitation	$ 500	$ 1,100	$ -	$ -	$ -	$ -
Other Transmission Line Rehabilitation	2,686	4,913	4,332	3,354	5,819	5,290
Total	$ 3,186	$ 6,013	$ 4,332	$ 3,354	$ 5,819	$ 5,290

The following project over $1 million is planned to be completed within the 2020-2024 term:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project includes expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment. This includes stubbing poles and replacing poles and cross-arms. The total cost of this project is $2.6 million, with a forecast of $1.5 in 2019 and $1.1 million in 2020, and an estimated in service date of 2020.

Transmission Urgent Repair:

The Transmission Urgent Repair program is required to repair or replace components that are in poor condition and in danger of immediate failure on the transmission system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions or other unexpected reasons that can cause outages or present risks, and must be addressed in an expedient manner. Forecasts are based on historical spending however annual spending varies due to the severity and number of structure failures.

Transmission Rights of Way

This program is required for acquiring rights of way and easements for existing transmission facilities that are in trespass on private property. Expenditures for this category will also address access issues with respect to existing rights of way. Many of the transmission lines, when initially constructed, did not have formal road access to sections of the right of way. Access is required for ongoing operation and maintenance of these lines. Table C3-33 below provides the 2017-2019 average and the 2020-2024 forecast capital expenditures for the ongoing Transmission Line Rights of Way program in addition to specific requirements over the 2020-2024 period.

Table C3-33: FBC Transmission Line Rights of Way Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
30, 32, 19 Lines Rights of Way	$ 39	$ 647	$ 651	$ 658	$ 656	$ 652
Transmission Rights of Way	428	453	453	464	471	484
Total	$ 466	$ 1,099	$ 1,104	$ 1,121	$ 1,128	$ 1,136

The following project over $1 million is planned to be completed within the 2020-2024 term:

- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring additional right of way upslope of the existing ROW for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages.

3.4.1.2.3 STATIONS SUSTAINMENT CAPITAL

FBC's Substation Sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks. Increases in expenditures for the 2020-2024 period are mainly due to a small number of larger discrete projects to address transformer and equipment condition.

Stations Sustainment capital is further broken down into four programs, and the 2017-2019 average and the 2020-2024 forecast capital expenditures are provided in Table C3-34 below.

Table C3-34: FBC Stations Sustainment Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Station Urgent Repairs	$ 634	$ 574	$ 594	$ 687	$ 614	$ 655
Station Assessment/Minor Planned	1,209	1,317	1,354	1,394	1,419	1,438
Transformer Replacements	420	2,263	-	-	-	6,518
Salmo Station Upgrade	n/a	3,718	7,154	-	-	-
Fruitvale Station Upgrade	n/a	-	-	-	-	3,802
Station Equipment	2,652	5,667	4,522	3,198	1,760	3,559
Total	$ 4,915	$ 13,538	$ 13,624	$ 5,279	$ 3,793	$ 15,971

Station Urgent Repairs

The Station Urgent Repairs program is required to address unexpected failures of in-service equipment. Factors that can result in component failures in substation systems include inclement weather, defective equipment, animal intrusions, and vandalism. These failures can cause outages or present safety or equipment risks that must be addressed in an expedient manner to maintain safe and reliable service. Forecasts are based on historical spending; however, actual annual spending varies due to the severity and number of equipment failures.

Station Assessment/Minor Planned Projects

This program involves ongoing condition assessments of FBC's 65 transmission and distribution substations for environmental, safety and reliability issues on a six-year cycle, and the completion of the required work identified from these assessments.

The Station Assessment and Minor Planned Projects program address the whole substation system, including equipment such as transformers, breakers, and batteries. The work resulting from the condition assessments is planned and executed in the subsequent years as Station Minor Planned Projects.

Station (T&D) Transformer Replacements

To maintain adequate levels of reliability, station transmission and distribution transformers will be replaced based on condition assessment which includes asset health, reliability, age, risk of failure, loading, outdated load tap changers and the impact to the FBC system. Specific planned expenditures for each transformer replacement are identified after completion of the condition assessment in the previous year. Coordination with growth planning will be pursued to identify areas where voltage conversions can result in station consolidation.

Table C3-35: FBC Station (T&D) Transformer Replacement Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
AS Mawdsley Transformer Replacemer	n/a	$ -	$ -	$ -	$ -	$ 3,802
Trout Creek Transformer Replacement	n/a	2,263	-	-	-	-
Kaleden Transformer Replacement	n/a	-	-	-	-	2,716
Total	n/a	$ 2,263	$ -	$ -	$ -	$ 6,518

The projects planned to be completed within the 2020-2024 term, as shown in the table above, are as follows:

- **AS Mawdsley Transformer Replacement:** The T1 transformer is currently 53 years old. Based on age and current condition, this transformer ASM T1 is due for replacement in 2024. The total estimated cost of this project is $5.0 million, with a 2024 forecast expenditure of $3.8 million and in service date of 2025.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition. This transformer is 52 years old and uses one of the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546); the acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicate a cracked LTC terminal board. The oil migrating between LTC and main tank will lead to carbon deposits on insulating materials and an unforeseen failure. The estimated cost of this project is $2.3 million in 2020 with an estimated in service date of 2020.
- **Kaleden Transformer Replacement:** This project is driven by asset condition. This transformer is 59 years old. A concerning fracture was detected in the LTC cast; the temporary fixing will be double-checked in 2018. Based on site observation, it was determined that the unit has a loose iron core which eventually can lead to the units' failure. The estimated cost of this project is $2.7 million in 2024 with an estimated in service date of 2024.

Salmo Station Upgrade

This project is driven by aging infrastructure and equipment condition at the Ymir and Salmo substations. Due to its outdated preservation system, the Ymir transformer has experienced periods with high moisture content in the paper insulation and unit failure is now only a matter of time. In addition, mercury was found to be used to seal the LTC link board for this unit. The Ymir station will be decommissioned and the load transferred to Salmo station. The Salmo transformer must also be replaced due to the unreliability of its LTC. With the retirement of Ymir station, the capacity at Salmo will need to be increased to support the additional load, and a second transformer installed to support contingency planning criteria. The estimated cost of this project is $10.5 million with an in-service date of 2021.

Fruitvale Station Upgrade

Similar to the Salmo Station Upgrade project, the Fruitvale Station Upgrade project involves decommissioning the Hearns Station because of equipment condition. The Hearns transformer is 68 years old and consists of three single phase units. Due to its outdated preservation system, the unit has experienced periods with high moisture content in the paper insulation and unit failure is now only a matter of time. The Hearns station will be decommissioned and the load transferred to Fruitvale Station, which requires a capacity increase and a second transformer to support contingency planning criteria. The metal-clad switchgear at Fruitvale, which has been in service since 1967, also requires replacement based on condition assessment. The estimated project cost is $10.6 million with an in-service date of 2025.

Station Equipment

Station Equipment expenditures include new and existing programs required to replace or refurbish obsolete or aging equipment, maintain or improve reliability of the substations. Specific planned expenditures for each substation are identified after completion of the condition assessment in the previous year. Table C3-36 below shows the components of Station Equipment capital expenditures, which are described below.

Table C3-36: FBC Station Equipment Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Generating Stations Assets	321	1,088	445	175	109	109
Ground Grid Upgrades	112	698	-	570	-	565
Minimum Oil Circuit Breaker Replacem	1,050	1,055	1,085	1,117	1,137	1,152
Bulk Oil Breaker Replacement	463	619	641	-	-	-
Station Oil Containment	237	700	326	274	273	380
Other Equipment	469	1,506	2,026	1,062	241	1,354
Total	$ 2,652	$ 5,667	$ 4,522	$ 3,198	$ 1,760	$ 3,559

Generating Stations Assets

This program is to address the condition of the FBC generator step-up stations assets. The areas of the stations that will be repaired are station connecting lines, ground grids, and metal, wood, and concrete structures. Based on the condition assessment of the generator step-up stations[145] on the Kootenay River hydro plants, an incremental expenditure is required in 2020, which will address the replacement of air-to-air bushings, concrete and metal structures repairs, transformer life extension and oil leak mitigation.

Ground Grids Upgrades

Station ground grids must function properly in order to minimize safety risk for employees and the general public who are in or around stations. In the event of an electrical fault on the system, the purpose of the ground grid is to provide a low impedance return path for fault current. If the ground grid is damaged or has deteriorated, the fault current can potentially follow other paths

[145] The scope of the ULE program did not include any upgrades of the generation stations assets.

such as through communications systems or water systems. This can result in increased hazard to employees and the general public.

Consistent with recommended Institute of Electrical and Electronics Engineers (IEEE) practices, FBC employs an ongoing program to test the effectiveness of ground grids at all stations. As part of the program, station ground grids are inspected and tested during scheduled Station Assessments. Both condition assessments and the ground grid studies are used to develop plans for any required remediation work.

In 2020, the expenditures are due to the requirement to add ground wells to the Grand Forks transmission station grid, and implement some of the recommendations from pervious grounding studies.

In 2022 and 2024, outstanding high priority deficiencies highlighted in the engineering condition assessments will be mitigated.

Minimum Oil Circuit Breaker Replacements

FBC's fleet of Minimum Oil Circuit Breakers (MOCBs) is aging and requires replacement to maintain acceptable standards of reliability. The average age of the MOCB asset class is 28 years, with the assets ranging in age from 20 to 44 years old. As this asset class ages, maintenance expertise and spare parts become increasingly scarce. When minimum oil circuit breakers operate, severe stress is put on the operating mechanism. These breakers will continue to be monitored and assessed, and replacement will be carried out.

Bulk Oil Breaker Replacements

FBC continues the replacement of bulk oil breakers with modern vacuum circuit breakers. The new units are more reliable and require less maintenance than bulk oil breakers. Replacing the breakers also removes the need to install oil containment pits and prevents stranding the oil containment pits when the breakers are removed from service at a later date. Replacement parts are also no longer available for these breakers and often have to be specially fabricated. This is program will be completed by the end of 2021.

Station Oil Containment

Some older FBC substations were often constructed without oil containment pits to prevent oil release into the environment. To reduce the risk of transformer oil contaminating soil, groundwater and nearby waterways, this program retrofits oil containment pits for legacy substations, either adding containment pits where none currently exist or upgrading containment pits that are considered inadequate. The work is prioritized to mitigate stations that pose the highest risk to the surrounding environment first**.** The increase in 2020 is due to work to be completed at F.A. Lee station prior to the Kelowna Bulk Transformer Addition.

Other Station Equipment

Expenditures for Other Substation Equipment include:

- Metal-clad switchgear has a typical life span of 40 to 45 years, and FBC will replace metal-clad switchgear which is nearing the end of its operating lifespan in several stations, based on condition assessment. In 2020 the increase is due to the replacement of the unit station switchgear at Trout Creek, which is planned in coordination with the transformer replacement to gain efficiencies.
- The repair, refurbishment or replacement of station switches are required for safety, operational and maintenance purposes. FBC has a population of more than 1100 switches in service across the full voltage range, and failures and unplanned maintenance interventions have risen in the last several years due to deteriorating/aging switch operating condition.
- Due to the inherited design, some instrument transformer types represent a safety hazard in the event of failure. Proactive replacement of instrument transformers are required to prevent such events.
- Animal protection cover-up of substation equipment to reduce the number of animal-caused outages.

3.4.1.2.4 DISTRIBUTION SUSTAINMENT CAPITAL

Distribution Sustainment capital expenditures are required to proactively manage the condition and integrity of FBC's distribution line facilities, manage the risk to employees and public safety, and ensure an acceptable level of service is maintained for customers.

The majority of Distribution Sustainment capital expenditures are forecast based on recent historical expenditures. Overall, expenditures in this category increase compared to the most recent three-year period as a result of the necessary replacement of aging conductors and potentially hazardous porcelain cutouts on distribution feeders, the replacement of sodium and mercury vapour street lights with more efficient LED lighting, and the mandated replacement of distribution equipment containing Polychlorinated Biphenyls (PCBs).

Table C3-37 below shows the 2017-2019 average and the 2020-20024 forecast distribution sustainment expenditures. Each category of expenditure is discussed below.

Table C3-37: FBC Distribution Sustainment Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Distribution Line Condition Assessment	$ 1,544	$ 1,645	$ 1,691	$ 1,632	$ 1,713	$ 1,864
Distribution Line Rehabilitation	3,146	2,802	3,148	2,872	2,680	3,150
Distribution Line Rebuilds	2,019	2,183	2,244	1,942	1,938	1,925
Distribution Urgent Repairs	3,112	2,620	2,748	2,732	2,823	2,865
Distribution Small Planned Capital	926	1,034	1,105	1,210	1,247	1,407
Forced Upgrades and Line Moves	2,264	2,578	2,564	2,656	2,570	2,758
PCB Environmental Compliance	731	2,677	2,721	2,663	3,124	2,444
Porcelain Cutouts Replacement	n/a	3,233	3,322	3,421	3,483	3,527
Meter Exchanges	55	127	130	140	140	141
LED Street Light Retrofits	370	787	-	-	-	-
Other Distribution Sustainment Projects	552	652	664	274	273	272
Total	$ 14,719	$ 20,337	$ 20,338	$ 19,542	$ 19,990	$ 20,353

Distribution Line Condition Assessment

The Distribution Line Condition Assessment program is based on an eight-year cycle of inspecting and testing all FBC distribution line facilities. The program consists of a pole test and treat and a condition assessment. The test and treat component of the program is aimed at the section of pole at the ground level and below. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying, apparatus and grounding) attached to the pole. If an issue is detected during the condition assessment, the deficiency is documented and corrected in the following year. The program is managed on an eight-year cycle to levelize both the annual costs and the resources required.

Distribution Line Rehabilitation

The specific rehabilitation projects for various distribution facilities involve expenditures for stubbing poles, replacing poles, cross-arms, insulators, guy wires, and correcting other defects identified through the previous years' assessments. The distribution line rehabilitation program deals with issues that, while not severe enough to require immediate repairs (in which case they would be carried out immediately under the distribution urgent repairs program), are serious enough that they must be addressed in the year following the condition assessment.

Distribution Urgent Repairs

The distribution urgent repairs program is required to repair or replace components that are in poor condition and in danger of immediate failure on the distribution system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions or other unexpected reasons that can cause outages or present risks, and must be addressed in an expedient manner. Forecasts are based on historical spending; however annual spending varies due to the severity and number of structure failures.

Distribution Line Rebuilds

This category involves the replacement of aged and deteriorated equipment on a larger scale than would typically be performed under the distribution line rehabilitation program. Items include rebuilding failing overhead and underground conductors, replacing rotted poles and platforms, replacing leaking transformers, and installing ground grids at ungrounded services, as well as the replacement of copper conductor in areas considered to be a risk to public or employee safety. These deficiencies are identified through condition assessment data, site assessments and normal daily operations.

Small Planned Capital

This program is similar to the distribution condition assessment and rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. Each year operational and safety concerns on the distribution system including storm damage, clearance problems and aging equipment are identified by field staff outside of the normal assessment cycle. Repairs to address these concerns are required to maintain a safe and reliable distribution system. The repairs are generally non-urgent in nature and consequently are not completed under the distribution urgent repair program.

Forced Upgrades and Line Moves

This program is required to complete distribution upgrades driven by third party requests. The following are potential situations where upgrades or line moves are required:

- Requests from governing authorities (e.g., MOTI or municipalities) to relocate distribution lines located on road allowance or highway right of ways to accommodate road widening or improvements;
- Requests to relocate distribution lines where FBC does not have sufficient land rights for the distribution line facilities located on customer property; and
- Third party utility requests for upgrade of FBC transmission and distribution line plant to accommodate a shared use arrangement.

Environmental Compliance – Distribution Equipment (PCB)

The federal PCB Regulations (SOR/2008-273) came into force on September 5, 2008. As per the PCB Regulations, the release of one gram of PCBs into the environment is prohibited. This prohibition applies to all PCBs, without exception and at all times, including during the conduct of activities permitted by the PCB Regulations. Although pole mounted transformers have an in-service exemption until 2025, the one-gram release prohibition still applies.

FBC has approximately 38,600 pieces of oil-filled distribution-class field equipment including transformers (pole and pad mount), reclosers, capacitors banks, metering units and regulators. Currently, the PCB level for majority of the equipment has been confirmed through testing or nameplate information. The proposed expenditures for this project are for the remediation plan which begins in 2019.

Porcelain Cutouts Replacement

FBC's distribution system uses fused cutouts for overcurrent protection and switching of distribution equipment, feeder branches and taps. These devices are necessary for the proper operation of FBC equipment. They provide a level of safety for employees, public, and equipment downstream from the cutout. Opening for faults, they limit the outage to the equipment affected rather than having the entire feeder trip.

Failures of porcelain cutouts are becoming more frequent and can potentially create a safety hazard. A faulty cutout may break apart causing falling debris and create an arc hazard from a potential phase to ground fault. Arc flash energy can create a safety hazard for employees, and cause damage to equipment. It can also cause prolonged outages to any customers that may be downstream from the failed cutout. Cutout failure reduces the reliability of FBC's service and is a potential hazard for employees and the public.

The cause of the failures may be from environmental effects, manufacturing processes, lack of quality control, or improper installation. Locating faulty in-service porcelain cutouts is almost impossible as only a close-up visual and physical inspection reveals the hair line fractures that lead to equipment failure.

The scope of this program is to replace 10,000 in-service porcelain cutouts, or 2,000 in-service porcelain cutouts per year, in the 2020 – 2024 period at an estimated cost of $17.0 million.

Meter Exchanges

This category includes the meter replacements and exchanges for metering equipment that fails during the metering compliance or meter re-test program. Metering infrastructure includes meters, current transformers, potential transformers and ancillary equipment.

The AMI project was complete in 2016; therefore, FBC has not had to exchange any meters for compliance purposes during the 2014 – 2019 period. Instead, FBC has only had expenditures for meters and ancillary equipment to cover meter damage, and meter failures. Beginning in 2020 FBC will begin the compliance sampling program again.

Other Distribution Sustainment Projects

Other distribution sustainment expenditures include the following:

- FBC has a number of padmount switchers in critical locations that are near end of life. These switches are 1980's vintage and often serve significant load that cannot be supplied from any other source. When these switches fail, they result in significant outages with long restoration times. The replacement of end-of-life SF6 gas and oil insulated switchers will continue to be prioritized based on condition and criticality. An added benefit with the new standard switchers installed is the Vacuum Fault Interrupter (VFI) protection that the manufacturer offers. Having more customers connected to these VFI protected switches allows much better protection coordination on the system, resulting in fewer customers affected by faults and in quicker fault location.
- The Underground Cable Replacement program began in 2011 and continues to be an important program for sustainment of the Kelowna network. The replacement of main 350MCM feeder cables manufactured pre-1990 continues to be the focus of this program. FortisBC has also experienced problems with aged 1/0 aluminum cables of similar vintage in recent years. This program may also include some proactive replacements of age 1/0 cable.
- Fault indicators provide a significant operational benefit by supporting the quick identification and localization of faults and subsequent repair of faulted cables. Without these fault indicators outage times can be greatly lengthened which negatively impacts customer reliability. In general, fault indicators should be installed on each primary phase conductor on every switcher node, every junction box node, and on cables leaving feed-through transformers. Fault indicators will allow failures to be located much

more easily and therefore improve fault isolation and system restoration in a cost-effective manner.

- FBC is retrofitting approximately 2,500 Type III legacy street lights with LED streetlights. This work began in 2018 and has a completion date of December 2020.

3.4.1.2.5 TELECOMMUNICATIONS CAPITAL

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

Telecommunications capital is further broken down into four programs, and the average 2017-2019 and forecast capital expenditures for the 2020-2024 period are provided in Table C3-38 below. Increases in the 2020-2024 timeframe are mainly driven by the need to upgrade or replace aging systems and by regulatory requirements.

Specific planned expenditures for telecommunications are identified after completion of the condition assessment in the previous year. Forecast expenditures are set based on historical expenditures.

Table C3-38: FBC Telecommunications Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Communications Upgrades	$ 247	$ 367	$ 379	$ 390	$ 397	$ 402
Station Smart Device Upgrades	428	323	380	329	328	326
SCADA Systems Sustainment	570	937	945	1,685	970	1,451
Systems Upgrades and Replacements	1,086	-	1,086	3,677	4,016	1,086
Other Telecommunications	186	190	194	200	204	206
Total	$ 2,516	$ 1,818	$ 2,983	$ 6,280	$ 5,915	$ 3,472

Communication Upgrades

This ongoing project funds upgrade projects for FBC telecommunications facilities. These upgrades will enhance the system operators' ability to monitor the status of the transmission and distribution system and respond to system events. Furthermore, the upgrades will maintain the integrity of the existing infrastructure used to protect the power system, FBC employees and the general public from damages and outages resulting from major system faults and events.

Some FBC telecommunication equipment is near or beyond its designed operational life. Individual components are unreliable, and manufacturers no longer supply spare parts or provide product support. In some extreme cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, resulting in long delays putting equipment back in service.

System Smart Device Upgrades

FBC has a number of aging and failing electronic relays that also do not meet current monitoring and protection industry standards. Replacement of these relays is a priority and will facilitate efficiencies in the operations, engineering and planning areas, and enhance system reliability by providing co-ordination of protective devices, accurate information and real time telemetry on system status, faults and other problems and decreasing the need for complex protection schemes. This ongoing sustainment program will update these devices and integrate them into the telecommunications network. In addition, ongoing upgrades to obsolete or failing intelligent electronic devices at substations will occur as needed.

The program will be managed by prioritizing upgrades based on several factors including device malfunctions, obsolescence and vintage, complexity of troubleshooting, probability of failure and the potential for cost and operational efficiencies benefiting system operation and planning.

SCADA Systems Sustainment

The SCADA sustainment program funds annual sustainment projects for SCADA software systems and infrastructure located at the System Control Centre or the Backup Control Centre and communications infrastructure directly connecting the System Control Centre to the Backup Control Centre. Additionally, as MRS standards continue to evolve, this program will fund MRS-related system upgrade projects that are necessary to maintain compliance with these standards.

Systems Upgrades and Replacements

A number of FBC's telecommunications systems have reached end of life and require upgrades or replacement, as described below. Also included in this category is the 2019 acquisition of fibre optic cable on FBC's transmission lines between Vernon and Penticton and some fibre spans near Christina Lake and Castlegar. Included in this category are three projects in excess of $1 million. Each one is discussed further below.

Backbone Transport Technology Migration

The current core data transport technology used by FBC for operational communications is Synchronous Optical Networking (SONET). The current network consists of four SONET rings, comprising about 30 sites supplemented by approximately five lower speed spur links. The balance of FBC facilities are served with several other technologies where appropriate including cellular, private radio, Ethernet, satellite, dial-up, and in some cases are not served at all.

The general trend in telecommunications industry has been to deploy high speed Ethernet Industrial Protocol (Ethernet/IP) technology to replace SONET. This technology has a much lower installed cost, higher bandwidth, is standards-based for interoperability and is more efficient for converged networks (voice plus data) than legacy technologies such as SONET. It is expected that the pool of vendors offering SONET equipment will continue decreasing and the operating and capital costs will increase in the future.

This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. This project will begin in 2022 and be completed in 2023. The estimated cost is $1.9 million.

SCADA System Replacement

FBC purchased and installed the current SCADA system in the 1980s. During this time, the SCADA system was very simple and monitored/controlled points only included some generation and major transmission assets.

Electric utility SCADA environments have changed significantly during the 2000s, due to the proliferation of inexpensive and near ubiquitous communications technologies and the growth of technology. Today, network security and MRS requirements are some of the most important considerations for SCADA networks and bolt on modules such as OMS, ADMS and Real Time Contingency Analysis that enhances the abilities of these systems adds to the complexity.

This project, with an estimated cost of $6.6 million, will begin in 2021 and be completed in 2024.

VHF Radio System Replacement

The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice.

In the last five years, FEI has been replacing its legacy system with a new digital system. While the system needs to be replaced, an opportunity exists to evaluate whether it will be advantageous to combine the FEI and FBC radio systems providing more contiguous coverage throughout both service territories and sharing costs.

The current system consists of 14 VHF repeaters (6 Okanagan, 3 Boundary, 5 Kootenays) and several VHF and UHF links connecting the system together.

The estimated cost of this project is $0.5 million in 2022 and $0.8 million in 2023 with an estimated in service date of 2023.

Other Telecommunications

This program includes the purchase of new or replacement communications equipment in support of field staff. This equipment includes landline equipment, radio communications for field use, and the installation of fibre cabling and wireless systems intended for multiple applications. These installations provide voice as well as data communications as required. This program supports the communications infrastructure needed for FBC to carry out general business operations, addressing the need for replacing or supplementing communications systems based on identified deficiencies. This program does not include any work for communications systems installed specifically for protection and control of the power system.

3.4.1.3 FBC Other Capital

Other capital is further broken down into Equipment, Facilities and IS expenditures.

Equipment expenditures include costs associated with specialized tools and equipment and fleet vehicles. Facilities expenditures include costs associated with the acquisition or leasing of land, facilities including office buildings and facilities equipment. IS expenditures include costs associated with information systems hardware, infrastructure and software requirements

Table C3-39 summarizes the forecast Other capital expenditures required over the 2020-2024 term.

Table C3-39: FBC Other Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Equipment	$ 2,791	$ 3,407	$ 3,338	$ 3,274	$ 3,681	$ 3,388
Facilities	1,978	3,264	2,346	2,346	2,346	2,346
Information Systems	8,915	9,081	9,028	9,136	9,254	9,400
Total	$ 13,683	$ 15,752	$ 14,712	$ 14,756	$ 15,281	$ 15,134

3.4.1.3.1 FBC EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

Fleet Vehicles

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 FBC.

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.

FBC depends on the availability of specialized, reliable, safe, and efficient vehicles. Deferring these planned vehicle expenditures increases the risk of negatively impacting employee and public safety, degrading service response times and increasing operating costs resulting from excessive repair costs, down time and equipment shortages. As such, the replacement of heavy fleet vehicles, service vehicles, passenger/light duty vehicles, specialty equipment and off-road vehicles is necessary for FBC to ensure the continued provision of safe and reliable service.

Tools and Equipment

This category provides tools required by employees to do their job safely, efficiently and at a level expected for the business. The tools and equipment budget is used to purchase and/or replace tools that have a value greater than $1,000. This budget covers tools and test equipment that is required by the various technical and trades employees at FBC. New tools are also purchased to improve ergonomics, to meet new equipment needs, and to replace outdated test equipment and other items to meet the broad range of operations tasks.

3.4.1.3.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. 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 internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

FBC has 17 non-plant office sites ranging from new to 80 years in age. When it is determined that an asset is no longer adequate, FBC will determine whether to upgrade or replace assets depending on condition, age and capacity to provide a suitable work environment with safe and efficient building workspaces. Facilities will continue to support replacement and upgrade programs of HVAC, mechanical, electrical, security, building envelope, building finishes as the assets reach the end of its service life.

This category also includes the replacement of furniture that has reached the end of its life cycle, as well as the replacement of fixtures to accommodate changing needs within the organization.

3.4.1.3.3 INFORMATION SYSTEMS

FBC'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. FBC relies on a base of core enterprise applications, SharePoint for document management and collaboration, ESRI GIS for mapping the utility electric network, Clevest Workforce Management for FBC field workers to receive and update work orders, and Cascade Plant Maintenance for Transmission and Generation. These applications are used to support FBC's business technology requirements. FBC 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.

In situations where the utility is implementing infrastructure and/or applications that will benefit both gas and electric customers FBC has established a shared asset framework. The framework provides for equitable distribution of costs for assets that have a shared use and benefit from combined ownership. The allocation of asset ownership is defined through licensing and separate requisitioning for components, based on usage of the shared asset by the respective organizations.

The 2017-2019 average and 2020-2024 forecast IS capital expenditures are summarized in Table C3-40 below.

Table C3-40: FBC Information Systems Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Information Systems Sustainment	$ 4,200	$ 3,631	$ 3,537	$ 3,604	$ 3,679	$ 3,782
Application Enhancements	773	1,100	1,122	1,144	1,167	1,190
Cybersecurity	1,790	950	969	988	1,008	1,028
Business Technology Applications	2,151	3,400	3,400	3,400	3,400	3,400
Total	$ 8,915	$ 9,081	$ 9,028	$ 9,136	$ 9,254	$ 9,400

The annual average IS budget for all of the categories shown in the table was approximately $9 million for 2017 to 2019. Overall, IS expenditures are growing at less than two percent per year relative to 2017 to 2019 average expenditures. Each of the four categories is discussed further below.

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.

Application Enhancements

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. The increased implementation of business tools over the last 5 years has increased the amount of applications requiring enhancements.

Cyber security

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 has required FBC to engage in additional testing, custom configuration and code changes to deploy the updates. Tools to monitor and counteract these threats have to be evaluated and implemented to maintain an acceptable level of cyber security. Also included in this category are expenditures required to meet BC's Mandatory Reliability Standards regarding cyber security.

Business Technology Applications

This category includes capital funding for initiatives that impact the way business is conducted and that support business units' 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.

The prioritization and selection of projects for each year are completed by the fall of the previous year, which ensures that projects with higher value to the Companies will be considered first when allocating finite resources.

In general, the pace of change in the IS Portfolio is greater than what FBC has experienced in the past. There is an expectation of and increased sophistication from customers and employees on the types of services provided that is dependent on technology. In addition, the rapid pace of change of technology necessitates more frequent replacement of systems due to obsolescence, loss of technical support, or risk of cyber threats, or to leverage the benefits of new functionality. Prudent investments in technology are not only key to realizing efficiencies in the day-to-day operation of the utility, but also to advancing innovation.

3.4.1.4 FBC Contributions in Aid of Construction

FBC's customer contribution policy provides customers a capital credit or allowance based on the amount of investment in distribution poles, conductors, and transformers for the rate classes covered in the applicable retail rate. Any investment in poles, conductors and transformers necessary to provide service to a customer in excess of this credit or allowance will be paid as a capital CIAC by the new customer. The recoveries in this category are forecast based on the anticipated receivable work for forced upgrades and historical levels of receivable work for new connects and identified recoverable projects.

The two tables below provide the realized and projected CIAC over the 2014 to 2019 period, and the forecasts for 2020 to 2024. The forecast for the CIAC is based on the historical ratio between the actual CIAC and the total New Connects or Forced Upgrades actual expenditures.

Table C3-41: FBC Actual and Projected Contributions in Aid of Construction, 2014-2019 ($000s)

	2014	2015	2016	2017	2018	2019P
New Connects	$ (7,618)	$ (6,562)	$ (6,779)	$ (8,649)	$ (10,657)	$ (7,587)
Forced Upgrades	(1,349)	(493)	(1,595)	(389)	(1,501)	(1,011)
Major Customer-Driven Projects	-	-	(61)	(3,317)	(1,057)	-
Total	$ (8,967)	$ (7,054)	$ (8,435)	$ (12,356)	$ (13,215)	$ (8,602)

Table C3-42: FBC Contributions in Aid of Construction Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
New Connects	$ (8,964)	$ (9,831)	$ (10,205)	$ (10,421)	$ (10,218)	$ (10,771)
Forced Upgrades	(967)	(1,276)	(1,260)	(1,293)	(1,253)	(1,354)
Major Customer-Driven Projects	(1,458)	-	-	-	-	-
Total	$ (11,389)	$ (11,107)	$ (11,465)	$ (11,712)	$ (11,473)	$ (12,125)

3.4.1.5 FBC Regular Capital Summary

Based on FBC's current knowledge of system requirements and industry drivers, FBC is forecasting increased levels of spending over the course of the 2020-2024 Proposed MRP term relative to 2014-2019.

FBC actively manages the capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall Regular capital forecast included in rates are subject to change, and FortisBC may identify new projects and programs that need to be added over the term of the Proposed MRP.

There are a number of external factors that could drive increases or decreases the forecast expenditures over the term. Significant pressures include:

- Internal and external labour costs;
- Currency exchange rates;
- Permitting costs; and
- Trade restrictions and tariffs.

Of these, the first two have been experienced in the past, but the last two are new or changing factors that could put pressure on FBC's capital costs. FBC proposes to review its forecast in its Annual Review for 2022 rates. Should FBC deem necessary, it will file an updated forecast of the 2023-2024 expenditures in 2022 to account for any material changes to the forecast that occur over that time period and ask for approval of the changes.

3.4.2 FBC Major Capital Projects

As noted above, Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a separate CPCN or other application. Pursuant to Order G-120-15, FBC is required to apply to the BCUC for a CPCN for projects in excess of $20 million in capital expenditures.

Below, FBC provides examples of the Major Project applications that it has identified to date which have been approved or which may arise during the course of the Proposed MRP Application.

- Upper Bonnington Old Units Refurbishment;

- Corra Linn Spillway Gate Replacement Project;
- Grand Forks Terminal Station Reliability Project; and
- Kelowna Bulk Transformer Addition.

Each of these projects is described in more detail below.

Upper Bonnington Old Units Refurbishment

Forecast Construction Timeline: 2017-2021

The Upper Bonnington Old Units Refurbishment Project (the UBO Project) was approved by Order G-8-17 and involves the replacement or refurbishment of various components of four of the generation plant's six units, which are at end of life and can no longer be operated in a safe, reliable, and environmentally responsible manner. The UBO Project will extend the productive life of the old Units for the next twenty years or more. The UBO Project is comprised of four smaller projects (one for each of the four generation units) in addition to project completion work on elements common to the four units.

Corra Linn Spillway Gate Replacement Project

Forecast Construction Timeline: 2017-2021

The BC Dam Safety Regulation amendments revised the "Dam Failure Consequence Classification", a measure that classifies dams based on the severity of the potential consequences of a dam failure. Due to the amendments to the BC Dam Safety Regulation, the Corra Linn Dam has been reclassified from a 'very high' consequence classification, to an 'extreme' consequence classification. Currently, the Corra Linn Dam spillway gates do not have the strength to withstand the recommended design earthquake for a dam with a consequence classification of 'extreme'. Accordingly, the spillway gates and the associated structures require either significant refurbishment or replacement, to align with these amendments and to be able to withstand the design earthquake. FBC is replacing the spillway gates and rehabilitating the associated infrastructure, as approved by Order C-1-17.

Grand Forks Terminal Station Reliability Project

Forecast Construction Timeline: 2019 – 2021

In the event of an outage to the Grand Forks Terminal transformer (GFT T1), the system is designed for a 63 kV backup supply from Warfield Terminal Station via the 63 kV transmission lines 9L and 10L. However, due to the condition of these lines, this backup 63 kV supply is not sufficiently reliable. A dependable secondary 63 kV supply is required to maintain reliability for the Grand Forks area in the event of a GFT T1 outage or failure. The Grand Forks Reliability project will install a second transformer at GFT (GFT T2), remove 44.6 km of 9L and 10L between Christina Lake and Cascade, and repurpose the remaining 20.8 km to distribution to continue supplying power to customers.

FBC filed a CPCN application for this project on November 19, 2018.

Kelowna Bulk Transformer Addition

Forecast Construction Timeline: 2020-2022

The addition of a new power transformer will be required to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions. Customers in Kelowna and the surrounding areas are currently served by two terminal stations: the FA Lee Terminal Station and the DG Bell Terminal Station. Following the outage of one of the two existing FA Lee Terminal transformers, the load on the remaining transformer can exceeds its emergency overload rating during the summer peak. This condition constitutes a violation of BC Mandatory Reliability Standard TPL-002, which requires that applicable thermal ratings are not exceeded following the loss of a single element. The standard requires that corrective plans must be implemented to eliminate the violation. FBC expects to file a CPCN application during 2019.

3.5 *CONCLUSION*

The forecast 2020-2024 capital expenditures reflect the appropriate level of capital expenditures needed to ensure the safety and reliability of the FortisBC gas and electrical systems and to provide service to new and existing customers. The proposed forecast approach for FBC Regular Capital and FEI Sustainment and Other Capital, coupled with the proposed formula approach for FEI Growth Capital, are needed to meet system requirements and customer needs in the changing operating environment while also providing incentive and flexibility to implement capital plans efficiently.

4. ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

4.1 INTRODUCTION

This section includes a description of the cost and revenue items required to determine the Companies' annual revenue requirements, which will be included in each year's Annual Review materials. FortisBC is proposing certain changes to the treatment of variances from forecast, which are also discussed.

As in the Current PBR Plans, where variances are proposed to be flowed through in future revenue requirements, they will be captured in a single Flow-through deferral account, except where a previously approved deferral account already exists. FortisBC is also proposing to align the manner in which FEI and FBC treat variances, where appropriate.

4.2 DELIVERY REVENUES (FEI)

Delivery revenues include amounts received from customers for the sale and delivery of natural gas[146], the provision of transportation service, revenues received under tariff supplements, and various other sources of tariff revenue. Natural gas usage rates are not under the control of FEI and the amount of natural gas customers consume can vary for many reasons.

Delivery revenues will be forecast each year and these revenues will be included in the determination of the revenue requirement and rates for the forecast year. Use rate-related revenue variations relating to residential and commercial customers (Rate Schedules 1, 2 and 3/23) will continue to be subject to the Revenue Stabilization Adjustment Mechanism (RSAM) mechanism which has been in existence since 1994. Flow-through treatment of all other variances in FEI's revenues was approved for the term of the Current PBR Plan and captured in the Flow-through deferral account. FEI proposes to continue this treatment as part of the Proposed MRPs.

4.3 REVENUE AND POWER SUPPLY (FBC)

Revenues include amounts received from customers for the sale of electricity, and various other sources of tariff revenue. The majority of variances in sales revenue are attributable to weather-related load variances, customer usage rate variances, and customer count load variances, all of which are not under the control of FBC.

Power supply expense includes power purchase expense, wheeling expense and water fees. Load variances due to variances in customer growth, usage, or weather also contribute to variances in power purchase expense. While unit prices, including market prices and regulated price changes (BC Hydro rates and other contracts whose prices are tied to BC Hydro rates) are not controllable, FBC has some ability to mitigate costs by optimizing its power supply portfolio

[146] The Commodity and Midstream (Storage and Transport) rates for FEI are set through separate processes.

in the short and medium term. FBC is proposing a Power Supply Incentive (PSI) which results in the sharing of power supply cost savings in order to provide an incentive FBC to reduce its Power Purchase Expense, as described in Section C8.3.7 and Appendix C7. FBC proposes to record the annual variances in Power Purchase Expense net of the PSI.

Revenues and Power Supply costs will be forecast each year and included in the determination of the revenue requirement and rates for the forecast year. Flow-through treatment of FBC's revenue and power supply variances was first approved by Order G-110-12, and during the Current PBR Plan, revenue and power supply variances were captured in the Flow-through deferral account. FBC proposes to continue this treatment in the term of the Proposed MRP.

4.4 *O&M*

In addition to index-based O&M, the Companies will continue to include a forecast of O&M for items that are excluded from the O&M indexing. The following items will be forecast each year by the Companies, for inclusion in rates for the forecast year, subject to approval by the BCUC:

- Pension and OPEB expenses;
- Insurance premiums;
- BCUC levies;
- FEI integrity digs;
- O&M (and the cost of service of related capital expenditures) to support the Companies' investments in a clean growth future. This category currently consists of NGT stations and tankers, variable LNG production, RNG, EV charging[147], but over the term of the Proposed MRPs either FEI or FBC may propose to include other initiatives in alignment with government policy; and
- Incremental costs to comply with legislatively mandated federal, provincial and municipal climate policy and with new Mandatory Reliability Standards (MRS). While the implications and associated costs to meet these and other draft requirements are currently being studied, the cost implications have not been accounted for in FortisBC's current operating or capital costs. FortisBC will bring forward its compliance plans and costs as the regulatory context becomes clear.

These items are discussed further below.

Flow-through or exogenous factor treatment for variances in the types of items listed above was approved in the Current PBR Plans, either due to their uncontrollable nature, or because they drive incremental revenues that are also afforded flow-through treatment. FortisBC proposes to continue this treatment over the term of the Proposed MRPs.

[147] Subject to the BCUC's determination in Phase 2 of the EV Inquiry.

In addition, over the term of the Proposed MRPs, the Companies may propose that new items that are not included in Base O&M should be forecast and subject to approval through the Annual Review process. Unlike exogenous factors, these new items may be in the control of FortisBC. These would be new initiatives that FortisBC believes are in the public interest to pursue.

4.4.1 Pension and OPEB Expenses, BCUC Levies, Insurance Premiums, and FEI Integrity Digs

The costs included in all four of these expense accounts (Pension and OPEB expenses, insurance premiums, BCUC levies, FEI integrity digs) are primarily outside of the control of FortisBC.

Currently, FEI and FBC have separate deferral accounts for variances from forecast Pension and OPEB expenses, and FortisBC proposes to retain the existing treatments for these expenses.

FEI has a separate deferral account for variances from forecast BCUC levies. Historically, FBC has not had deferral treatment for BCUC fee variances, but due to the significant increases in BCUC levies experienced over the Current PBR Plan, FortisBC proposes to harmonize the treatment between the Utilities, and to establish a deferral account for variances in BCUC levies for FBC.

During the term of the Current PBR Plans, insurance variances have been captured in a Flow-through deferral account for both FEI and FBC. FortisBC proposes to continue with this treatment.

FEI also proposes to capture variances in FEI's integrity digs in the Flow-through deferral account as discussed in Section C2.4.2.2.3.

To summarize, with the Proposed MRPs, FortisBC proposes the same deferral accounts and treatment for the first three items for both FEI and FBC. Integrity digs are an issue unique to FEI, as discussed further in Section C2.4.2.2.3. All four expenses will be forecast annually and reviewed by the BCUC in the Annual Review process, and variances will be captured in FEI's and FBC's respective Pension and OPEB deferral account, BCUC Levies Variance deferral account, or Flow-through deferral account.

4.4.2 Investments in a Clean Growth Future

FortisBC proposes that its investments that are in alignment with its Clean Growth Future submission should be forecast outside of indexed O&M. This currently includes NGT fuelling stations and tankers, variable LNG production costs, RNG, and EV charging stations. However, FortisBC may propose to add other initiatives to this category over the term of the Proposed MRPs.

4.4.2.1 NGT Fuelling Stations and Tankers (FEI)

The cost of service (capital and operating costs) to support FEI's growing NGT fuelling station and mobile refueling tanker business have been forecast annually and trued up through the Flow-through deferral account during the term of the Current PBR Plan. Since these costs support incremental revenues that are also subject to flow-through treatment, FEI proposes to continue with this treatment with the Proposed MRP.

4.4.2.2 Variable LNG Production Costs (FEI)

Each year of the Current PBR Plan, FEI forecasts all incremental costs associated with the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers and iso-containers to supply LNG sales from the Tilbury and Mt. Hayes LNG facilities. Any variances in these costs are captured in the Flow-through deferral account and returned to or recovered from customers in the following year. In its application for the Current PBR Plan, FEI proposed this treatment primarily due to the unpredictable nature of the costs during a period of time when Tilbury 1A was under construction, and when the LNG for transportation was undergoing a period of significant growth. As such, most of the costs at the time were variable in nature. Now that Tilbury 1A will be fully in service by the end of 2019, and the labour, materials and administration costs associated with running Tilbury as a combined operation will have stabilized, FEI has revised the treatment such that fixed costs of running the LNG Plants regardless of its use are included in Base O&M (which will be escalated by the approved inflation factor through the annual indexing of O&M). The remaining variable LNG production costs (i.e., liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers with LNG, etc.), which fluctuate and depend on sales volumes, are forecast each year as part of the Annual Review process, and trued up to actual in the following year through the Flow-through deferral account. Please refer to Section C.2.4.2.2.3 for a discussion of this treatment and the calculation of the allocation.

Similar to the treatment of Tilbury 1A operating costs during the Current PBR term, FEI proposes that any operating costs related to future expansions of Tilbury that come on-stream during the term of the Proposed MRP would be accorded the same flow-through treatment.

4.4.2.3 RNG Program Costs (FEI)

In the Current PBR Plan, FEI forecasts each year the capital and operating costs to support the RNG program. These costs are ultimately transferred to the BVA for recovery from biomethane customers through the BERC rate, with any unrecovered balances transferred to the BVA Rider deferral account and recovered from non-bypass rate payers through the BVA rider. FEI's Annual Reviews provide transparency of program costs, recoveries and inventory activity, including a calculation of the BVA Rider each year.

The current mechanism transfers the forecast December 31 balance in the BVA, including the unsold biomethane premium, net of the transfer of unsold inventory and remaining supply costs, to the BVA Rider deferral account. The BVA Rider is then set on a forecast basis to recover the balance in the BVA Rider deferral account from all non-bypass customers effective January 1 of the following year. In compliance with the BCUC's direction, FEI has reviewed this mechanism in Appendix B9. As set out in Appendix B9, FEI recommends that the BVA transfer mechanism should continue. FEI also proposes that the interconnection costs for the seven interconnection facilities that FEI initiated when the RNG Program was approved on a pilot basis be accounted for in the BVA, consistent with all other interconnection costs that were incurred after the RNG was approved on a permanent basis.

With this change, all RNG-related costs will be forecast each year, and any variances will be captured in the Flow-through deferral account with actual costs ultimately accounted for in the BVA.

4.4.2.4 Electric Vehicle (EV) Charging Stations (FBC)

At the time of filing, Phase 2 of the BCUC's EV Inquiry is underway. This Inquiry will determine whether FBC can invest in EV charging station assets as part of its regulated business, and, if so, under what parameters. Provided that FBC does include EV charging stations in its rate base, FBC proposes to forecast both the capital and the operating costs associated with the stations each year and record any cost of service variances in the Flow-through deferral account. EV charging stations will generate incremental tariff revenue, and these revenues will also be subject to flow-through treatment.

4.4.3 Incremental Regulatory and Policy Driven Costs

FortisBC proposes to forecast annually any incremental costs that it incurs in complying with legislatively mandated federal, provincial and municipal climate policy and with new MRS. Examples of such items would include new regulations to implement government climate policy discussed in Section B1.2 of the Application, and new MRS. The cost implications for any draft or new requirements to implement government climate policy, such as the federal Clean Fuel Standard, have not been accounted for in FortisBC's current operating or capital costs. FortisBC will bring forward its plans to comply with changes in regulations to the extent they drive incremental costs for BCUC approval as the regulatory context becomes clear.

Over the course of the Current PBR Plan, the BCUC granted consecutive approvals of exogenous factor treatment for FBC's costs to comply with new MRS. Rather than continuing to apply for exogenous factor treatment for these costs which FBC is clearly required to undertake, FortisBC proposes that these costs be treated as a forecast item outside of indexed O&M and outside of Regular capital.

A similar treatment should be applied to the incremental costs to comply with legislatively mandated federal, provincial and municipal climate policy. Like MRS costs, these costs will be required to be undertaken by FortisBC. For example, FortisBC will need to incur costs to comply with new federal regulations implementing the Pan-Canadian Framework. As these are new requirements and costs, it is not possible to anticipate the nature or amount of these costs and incorporate them into the Base O&M and forecasts of Regular capital. They are therefore more appropriately forecast each year.

Variances from the forecast amounts embedded in revenue requirements will be captured in the Flow-through deferral account.

4.5 *DEPRECIATION AND AMORTIZATION*

Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include plant additions consistent with both the forecast Regular capital expenditures and (for FEI) the formula-based Growth capital expenditures, as well as any Major Capital projects approved for inclusion in rate base.

Amortization of deferrals will be forecast for each Annual Review and actual amortization expense each year will equal the approved amount.

4.6 *PROPERTY TAXES*

Under the Current PBR Plans, property taxes are forecast annually, and any variances are captured in the Flow-through deferral account. This is because levels of property taxes levied are driven primarily by legislation, market values of properties and/or political program, all of which are outside the control of the Companies. FortisBC proposes to continue this treatment over the term of the Proposed MRPs.

4.7 *OTHER REVENUE*

The Companies will continue to forecast other revenues each year in the Annual Reviews for the Proposed MRPs, and will include appropriate discussion of each of the items. Components of other revenue that currently have deferral account treatment are FEI's Southern Crossing Pipeline Third Party Revenue, CNG & LNG Service Revenue and RNG Other Revenue. FortisBC proposes to continue this treatment. FortisBC is proposing that the risk of variances in other components of this other revenue item will be to the account of the shareholder as they typically are under a cost of service regime.

4.8 *INTEREST EXPENSE*

Each year, FortisBC will forecast short-term and long-term interest rates and interest expense for the upcoming year. Interest expense is largely outside of the Companies' control, and interest rates have historically been subject to deferral account treatment (either through a specific Interest Variance deferral account or the broader Flow-through deferral account). Debt capital markets are dynamic and volatile, changing constantly to reflect current and expected economic conditions and government monetary and fiscal policy. While FortisBC takes appropriate measures to develop a forecast of interest rates, it has no control over actual interest rates and, therefore, little control over the forecasting risk that is associated with interest rates. During the term of the Proposed MRPs, FortisBC proposes to capture variances in interest rates, volumes and timing of issuances on long-term debt, as well as variances in interest rates for short-term debt, in the Flow-through deferral account.

4.9 *INCOME TAX RATES*

Each year, FortisBC will forecast income taxes, based on currently enacted income tax rates. These rates are outside of the Companies' control, and variances have historically been subject to deferral account treatment (either through a specific Income Tax Rate variance deferral account or through the broader Flow-through deferral account). FortisBC has no control over whether governments change the income tax rates or laws subsequent to submitting revenue requirements forecasts to the BCUC for approval. Governments have previously made changes to tax laws and income tax rates, which have led to variances from income taxes approved for rate-setting purposes. For the Proposed MRPs, FortisBC proposes to capture variances in income tax rates in the Flow-through deferral account.

4.10 *EXOGENOUS FACTORS*

In the nomenclature of PBR, non-controllable and unforeseeable costs that flow-through to rates are referred to as exogenous factors. Consistent with the Current PBR Plans, FortisBC proposes that during the term of the Proposed MRPs, customers' rates will be adjusted either up or down for the cost of service impacts of O&M and capital costs caused by exogenous factors that are beyond the control of the Companies. Exogenous factor treatment of such costs will ensure that customers pay only for the actual costs in circumstances where FEI does not control the level of expenditures.

As during the Current PBR Plans, FortisBC will identify in its Annual Reviews exogenous factor events that have occurred or that are forecast to occur. Examples of events that would qualify for exogenous factor treatment include:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to BCUC decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).

The 2014 PBR Decisions established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:[148]

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

During the Current PBR Plans, exogenous factor treatment was approved for the Companies for the provincial EHT introduced in 2019 and a reduction in MSP premiums in 2018 and 2019[149]. Exogenous factor treatment has also been approved for FBC for wildfire damage repair costs[150] and for costs related to the introduction or amendment of MRS.[151] Ongoing costs and savings related to the EHT, MSP and MRS events are included in Base O&M and Base capital for the Proposed MRPs as set out in Section C2.4.2 and C2.5.2.

The 2014 PBR Decisions defined the materiality threshold at 0.5 percent of each Company's 2013 Base O&M.[152] In their Compliance filings, FEI and FBC calculated their respective materiality thresholds, resulting in thresholds of $1.140 million (0.5 percent times $228.019 million) and $0.301 million (0.5 percent times $60.159 million), respectively.[153]

Consistent with its position in the 2014 PBR proceedings, FortisBC believes that a materiality threshold is neither required not helpful. At that time, FortisBC stated that it should have the ability to bring forward any exogenous factor for discussion and review at Annual Reviews, for the BCUC to determine the appropriate treatment of the costs or savings. Further, based on its experience under the Current PBR Plans, FortisBC believes the materiality threshold resulted in confusion and lengthy submissions on how to define a threshold and how it should be applied, and that it would be administratively more simple and more efficient to bring forward for consideration any exogenous factors for approval that otherwise meet the criteria.

4.11 *RETURN ON EQUITY*

With regard to the allowed ROE, the BCUC approves both the ROE and the equity component within the capital structure of each of the Companies. When forecasting ROE and capital

148 Order G-138-14, pages 97-98 and Order G-139-14, page 94.
149 Orders G-237-18 and G-246-18.
150 Order G-202-15.
151 Orders G-202-15, G-8-17, G-38-18 and G-xx-18.
152 Order G-138-19, page 99 and Order G-139-18, page 95.
153 Approved by Orders G-164-14 and G-182-14.

structure, FortisBC will incorporate any BCUC-approved changes to these items such that there is no variance in the revenue requirement associated with the return on equity.

4.12 *RATE BASE OTHER THAN PLANT IN SERVICE*

Sections C3.3 and C3.4 explains the forecasting of Regular capital expenditures. There are several smaller components of rate base other, such as working capital and deferred charge balances, which are forecast each year in the Annual Review process. These items, including deferral account balances, will continue to be forecast each year in the Annual Review process.

4.13 *SUMMARY*

FortisBC's proposed treatment of each revenue requirement line item is included in Table C4-1 below. FortisBC notes that the accumulating differences between forecast/formula and actual spending will give rise to variances in rate base carrying costs (i.e., return on rate base, depreciation expense and taxes). FortisBC proposes that these variances will accrue to the shareholder, with the exception of variances related to the NGT, LNG, RNG and similar programs, and incremental costs incurred in complying with legislatively mandated federal, provincial and municipal climate policy and with new MRS, all identified above as having flow-through treatment.

Table C4-1: Treatment of Variances in Revenue Requirement Items from Forecast

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

5. DEFERRAL ACCOUNTS

5.1 *INTRODUCTION*

FEI and FBC use rate base and non-rate base deferral accounts to the benefit of customers and the Utilities as described in this section. Consistent with the BCUC's Regulatory Account Filing Checklist[154], FortisBC classifies its deferral accounts as one of forecast variance, rate smoothing, benefit matching, retroactive expense, or other deferral accounts.

The section below includes a discussion on new deferral accounts and changes to existing deferral accounts. FEI is requesting approval for two new deferral accounts, and the modification to the contents of one deferral account. FBC is requesting approval for three new deferral accounts, and the modification to the contents of one deferral account. A complete list of existing deferral accounts can be found in Appendix D1-1 for FEI and D1-2 for FBC.

5.2 *CONTINUATION OR MODIFICATION OF PREVIOUSLY APPROVED DEFERRAL ACCOUNTS*

In the discussion below, the Companies seek the continuation of the Flow-through deferral account for the term of the Proposed MRPs.

5.2.1 Flow-Through Deferral Accounts (FEI and FBC)

FEI and FBC are requesting to continue using the existing Flow-through deferral account during the term of the Proposed MRPs. As approved through BCUC Orders G-162-14 and G-163-14: "(*t)he flow-through deferral account is approved to be utilized for the duration of the PBR period only.*"

In the Proposed MRPs, the Flow-through deferral account will continue to capture the annual variances between the approved and actual amounts for those costs and revenues which are included in rates on a forecast basis, are proposed for flow-through treatment as identified in Section C4, and which do not have a separately approved deferral account. The specific items included in the Flow-through account for the term of the Proposed MRPs are set out in Section C4, Table C4-1.

5.3 *NEW DEFERRAL ACCOUNTS*

The Companies propose to establish new deferral accounts required for the implementation of the Proposed MRPs as identified below. Table C5-1 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to the deferral accounts requested in Sections 5.3.1 and 5.3.2 below.

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[154] BCUC Log 53608 dated May 3, 2017.

5.3.1 Forecast Variance Deferral Accounts (FBC)

5.3.1.1 BCUC Levies Variance Account (FBC)

FBC is seeking approval of a deferral account to collect the annual variances between the actual BCUC levies incurred and the amount forecast in O&M expense. This treatment aligns with the FEI treatment for BCUC levies, as approved through BCUC Order G-112-04. FBC also seeks approval to amortize this deferral account over one year, consistent with the FEI approved treatment.

5.3.2 Other Deferral Accounts (FEI and FBC)

5.3.2.1 MRP Incentives Account (FEI and FBC)

In Section C8, FortisBC proposes a suite of traditional and targeted incentives. FEI and FBC seek approval to establish for each utility a non-rate base deferral account attracting a WACC rate of return. The deferral account will capture the traditional incentive, described in Section C8.2, proposed as 50 percent of the ROE variance between achieved (before targeted incentives) and allowed. The projected incentive amount, determined each year, will be returned to (or collected from[155]) customers through amortization. FortisBC will make a final determination of the ROE for sharing after the year end, with any differences between the projected and actual amount included in the calculation of the earnings sharing for the following rate setting year. This method is consistent with the method the Companies have used for the 2014-2019 Earnings Sharing deferral account.

The Companies will also use this deferral account to capture the targeted incentives described in Section C8.3. The targeted incentive amount will be determined each year after the year end and added to the deferral account in the subsequent year. This amount will then be collected from customers through amortization in the next rate setting year.

5.3.2.2 Innovation Funding Account (FEI and FBC)

As discussed in Section C6, each of the Companies is seeking approval of a deferral account to collect a charge of $0.40 and $0.30 per customer per month for FEI and FBC, respectively, which will fund the Companies' annual innovation activities. These proposed riders will sum to approximately $4.9 million dollars per year for FEI, and $0.5 million per year for FBC. The charge will be in the form of a rider on the basic charge, and be charged on a per customer basis so that all of FEI's and FBC's customers fund innovation equally. The amounts collected from customers will be recorded as credits in the deferral account and the expenditures by the Companies will enter the deferral account as debits. The deferral account balance will not be trued up each year but rather will continue through the term of the Proposed MRP with a commitment by the Companies not to spend more than collected. The deferral account will be

155 If achieved ROE is less than allowed.

non-rate base attracting a WACC rate of return. At the end of the Proposed MRPs the unused balance in the deferral account will be returned to customers.

1

Table C5-1: Deferral Account Filing Considerations

Item	Consideration	BCUC Levies Variance (FBC)	MRP Incentives (FEI and FBC)	Innovation Funding (FEI and FBC)
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests to establish a new regulatory account.	FEI and FBC request to establish a new regulatory account.	FEI and FBC request to establish a new regulatory account.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The account will be used to capture the variance between actual BCUC levies and the annual forecast amount.	The account will be used to capture the incentives for both customers and shareholders for achieving certain targets within the period of the Proposed MRPs.	The account will be used to capture both the innovation funding costs and the offsetting rider recoveries from customers.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	Similar to the equivalent deferral account approved for FEI, the account should continue in perpetuity to ensure both customers and shareholders are held whole and pay for actual costs incurred.	The term of the account will be for term of the Proposed MRPs.	The term of the account will be for the term of the Proposed MRPs to align with the request in Section C6.

Item	Consideration	BCUC Levies Variance (FBC)	MRP Incentives (FEI and FBC)	Innovation Funding (FEI and FBC)
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of this deferral account, the costs could either continue to be forecast as part of the O&M formula, with variances shared 50/50 between the utility and ratepayers, or included as a forecast O&M expense outside of the O&M formula and trued up annually by way of the Flow-Through deferral account. FBC considers the existing treatment of including in the O&M formula to not be the appropriate treatment as these costs are outside of the utility's control and any variances in actual costs, either positive or negative, should not be subject to sharing. The option of including in forecast O&M and trueing up through the Flow-through deferral account is essentially the same treatment as creating the BCUC Levies Variance account; however, this option is only equivalent if the Flow-through account continues into perpetuity. FBC believes it is simpler and more transparent to create a separate deferral account for these costs going forward.	Given the mechanics of these incentives, and that part of the incentives may be amounts recoverable from or payable to customers by the shareholder in a subsequent year, FEI and FBC do not believe there is a viable alternative treatment to establishing a deferral account to distribute these costs. Theoretically, one option could be to raise or lower the test year ROE to ensure prior year incentives are incorporated in current year rates; however, FEI and FBC do not believe the forecast ROE should vary from that approved in the latest cost of capital proceedings.	In the absence of this deferral account, innovation funding costs could have been forecast within O&M for each year of the term of the Proposed MRPs. The costs would form part of the cost of service and be recovered through delivery rates. However, even if costs were forecast each year, a deferral account would still be required to capture variances between actual and forecast costs, to ensure customers are held whole. Additionally, including the costs in O&M and, correspondingly, delivery rates would result in an allocation of costs to customers on a volumetric basis. The rider approach proposed in Section C5.3.2.2 allocates the same amount to each customer.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	FBC has little to no control over the annual levy amounts.	These amounts are generally within management's control.	These amounts are generally within management's control.

Item	Consideration	BCUC Levies Variance (FBC)	MRP Incentives (FEI and FBC)	Innovation Funding (FEI and FBC)
b)	the degree of forecast uncertainty associated with the item;	The amount has a relatively high degree of uncertainty given the number of inputs that likely are involved in deriving the BCUC's annual fees.	The amounts used to determine the sharing have some uncertainty.	See Section C6. While the rider recovery amount is relatively certain, the timing of expenditures on innovation funding costs will have some variability from year to year.
c)	the materiality of the costs	Given the BCUC Levies represent approximately 0.4% of the forecast Base O&M costs, the materiality of the costs can likely be considered moderate. However, the costs have almost doubled during the term of the Current PBR PLans, and the trend is expected to continue.	The materiality of the costs used to determine the sharing amount is high. However, given the sharing account itself is a variance-type account and would be forecast with zero additions for the test year, the actual additions to the account may or not be material depending on the actual incentive levels achieved.	Given the Innovation costs represent approximately 2.0% of the FEI forecast Base O&M costs and 0.9% of the FBC forecast Base O&M costs, the materiality of the costs can be considered moderate to high.
d)	any impact on intergenerational equity	FBC is seeking to recover or return the variance in costs over one year, which serves to match the costs and benefits. See Section C5.3.1.1. There are no intergenerational inequities inherent in this practice.	FEI and FBC are seeking to recover or return the incentives over one year, which serves to match the costs and benefits. See Section C5.3.2.1. There are no intergenerational inequities inherent in this practice.	FEI/FBC are seeking to recover the costs, via rate rider, in the same year the costs are incurred, which serves to match the costs and benefits. See Section C5.3.2.2. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or I other.	FBC classifies this account as a forecasting variance account since the deferral addition is derived from a variance between actual costs and forecast costs.	FEI/FBC classifies this account as a forecasting variance account since the deferral addition is derived from a variance between actual costs and recoveries and forecast costs and recoveries.	FEI/FBC classifies this account as a forecasting variance account since the deferral addition is derived from a variance between actual costs and recoveries and forecast costs and recoveries.
VI.	Identify if the regulatory account is a cash or non-cash account.	This account is a cash account.	This account is a cash account.	This account is a cash account.

Item	Consideration	BCUC Levies Variance (FBC)	MRP Incentives (FEI and FBC)	Innovation Funding (FEI and FBC)
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include variances from annual BCUC levy amounts forecast in O&M.	Additions to this account will be the calculated incentive amounts either to be returned to or recovered from customers for the duration of the term of the Proposed MRPs.	This account will capture annual innovation funding costs of approximately $4.9 million for FEI and $0.5 million for FBC for the duration of the Proposed MRPs. In addition, this account will capture rate rider recoveries from customers for approximately the same amounts. See Section C6.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements/annual reviews by way of amortization expense.	Additions to the account are recovered or refunded in revenue requirements/annual reviews by way of amortization expense.	Annual costs are recovered via a fixed rate rider on the basic charge to ensure all customers pay an equal amount. Any residual balance in the deferral account at the end of term of the Proposed MRPs will be addressed in a future rate-setting application.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FBC is seeking to recover or return the variance in costs over one year, which serves to match the costs and benefits. See Section C5.3.1.1.	FEI/FBC are seeking to recover or return the additions to the account over one year, which serves to match the costs and benefits. See Section C5.3.2.1.	Costs will generally be recovered in the year they are incurred via the rate rider. This serves to match the costs and benefits. See Section C5.3.2.2.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	This account should be a rate base deferral account and therefore implicitly financed using the weighted average cost of capital (WACC), consistent with the financing of the FEI BCUC Levies Variance account.	This account should be a non-rate base deferral account attracting a WACC rate of return. This treatment is appropriate as it ensures both shareholders and customers are held whole for actual costs recorded to the account.	This account should be a non-rate base deferral account attracting a WACC rate of return. This treatment is appropriate as it ensures both shareholders and customers are held whole if actual costs or rider recoveries vary from forecast each year.

Item	Consideration	BCUC Levies Variance (FBC)	MRP Incentives (FEI and FBC)	Innovation Funding (FEI and FBC)
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The BCUC's review of the BCUC Levies Variance deferral account should occur as part of this Application's process.	The BCUC's review of the MRP Incentives deferral account should occur as part of this Application's process.	The BCUC's review of the Innovation Funding deferral account should occur as part of this Application's process.

5.4 SUMMARY OF APPROVALS SOUGHT RELATED TO DEFERRAL ACCOUNTS

The BCUC has indicated in the Decision accompanying Order G-7-03 that its Orders supporting deferral accounts continue in force until a change is approved by the BCUC. FEI and FBC will continue to use existing deferral accounts as approved, except as articulated in this Application.

Table C5-2 provides a summary of the request for approvals in this Application related to all deferral accounts.

Table C5-2: Summary of Deferral Account Requests

Type of Change	Account	Company	Return requests	Additional requests
New Account	BCUC Levies Variance Account	FBC	Rate Base requested	Section C5.3.1.1; amortization period of 1 year commencing January 1, 2021.
	MRP Incentives Account	FEI & FBC	WACC requested	Section C5.3.2.1; amortization period of 1 year commencing January 1, 2021.
	Innovation Funding Account	FEI & FBC	WACC requested	Section C5.3.2.2; costs will be recovered through rider. Any residual balance will be addressed at the end of the term of the Proposed MRPs.
Other	Flow-through Account	FEI & FBC		Section C5.2.1; extend the use of this deferral account for the duration term of the Proposed MRPs and include items set out in Section C4.

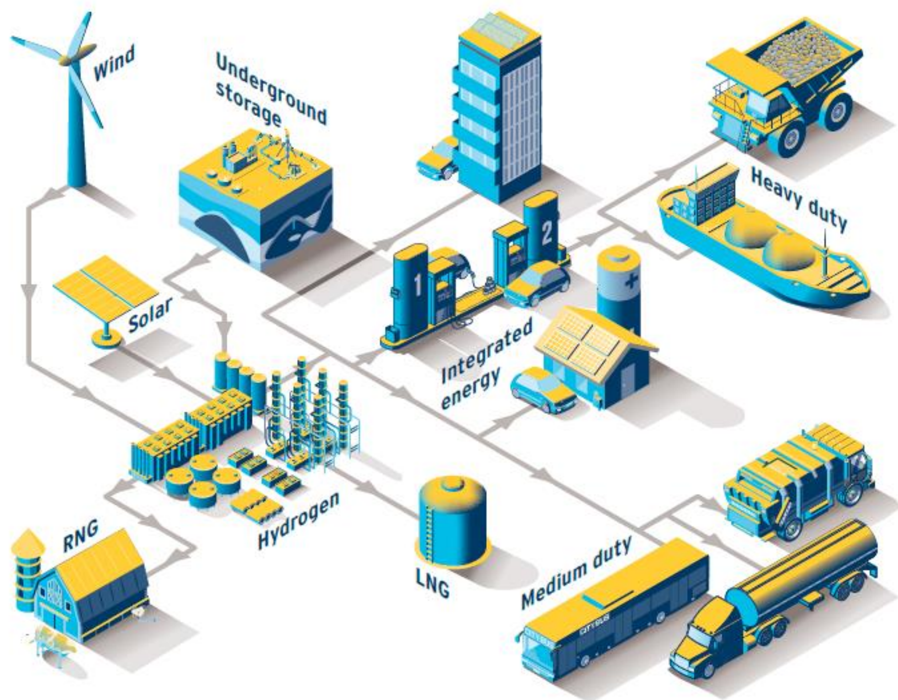
6. FORTISBC CLEAN GROWTH INNOVATION FUND

6.1 *INTRODUCTION*

As discussed in Sections B1 and B3, policy direction from all levels of government moving toward decarbonization has created an increased need for innovation and the adoption of new technologies. In this context, FortisBC has a clear vision for our future as described in our submission to the Provincial government's recent CleanBC public consultation process:

> We believe that FortisBC has an important role to play in helping British Columbians 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, transportation [and industrial] sectors.[156]

Figure C6-1: FortisBC's Clean Growth Pathway to 2050



To realize this vision, the Companies are proposing the creation of a Clean Growth Innovation Fund (the Fund) to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for our customers. The Fund will assist FortisBC in addressing the expectation to reduce emissions and support the transition to a lower carbon economy while maximizing the use of its energy delivery systems for the benefit of its customers.

Table C6-1 summarizes the main features of the Fund.

[156] Appendix A5, page 2.

Table C6-1: Features of the Clean Growth Innovation Fund

Feature	Description
Responsive to climate policy	• Focuses on innovative activities that reduce GHG emissions.
Responsive to customer expectations	• Focuses on bringing forward cost-effective energy solutions which reduce customer emissions.
Clear focus for innovative activities	• Complementary and incremental to current activities. • Both pre-commercial and commercial stages of commercialization. • Span entire utility value chain (supply, transmission & distribution, and end uses).
Predictable funding	• Monthly charge of $0.40 for FEI's and $0.30 for FBC's customers. Annually, $4.9 million for FEI and $0.5 million for FBC.
Robust framework	• Three stages to develop projects (identification, evaluation and selection, and execution). • Senior management oversight and external advisory group. • Reporting in Annual Review process. • Unspent funds will be recorded in a deferral account and carried forward for the remaining term of the Proposed MRP.

Section C6.2 describes how all levels of government are relying on market innovation to meet ambitious climate objectives and, as demonstrated in several case studies, responsibility for advancing innovation is shared between utilities, regulators and policy makers.

Section C6.3 provides context around the evolution of innovation funding, and examples of innovation funding in place in other jurisdictions.

Section C6.4 describes how the Fund complements FortisBC's current innovation activities and addresses crucial gaps.

Section C6.5 describes the Fund's purpose, objectives, guiding principles, stages of project development, governance, reporting and accounting treatment.

6.2 *INNOVATION AND CLIMATE OBJECTIVES*

6.2.1 Paris Agreement Commitments Set the Stage for Innovation

Climate policies aimed at meeting ambitious GHG reduction objectives are being implemented across all levels of government. Innovation is widely recognized as being of paramount importance in adapting to meet these objectives.

The Pan-Canadian Framework outlined Canada's goal to reduce GHG emissions by 30 percent from 2005 levels by 2030. Canada, as a signatory to the Paris Agreement, has also committed to reduce emissions over the medium to long-term in line with limiting global average temperature increases to well below 2 degrees centigrade above pre-industrial levels. To achieve this, Canada has set a longer-term target to reduce GHG emissions by 80 percent by 2050. Similarly, BC renewed its GHG emission reduction targets in 2018 by legislating a 40 percent reduction by 2030, 60 percent reduction by 2040 and 80 percent reduction by 2050.

Mission Innovation is a global initiative of 23 countries (including Canada) and the European Union that was established in 2015 at the 21st United National Framework Convention on Climate Change Conference of the Parties in Paris. Mission Innovation was created to highlight that accelerating clean energy innovation is essential to limiting the rise in global temperatures to well below 2˚C. Its goal is to "accelerate the pace of clean energy innovation to achieve performance breakthroughs and cost reductions to provide widely affordable and reliable clean energy solutions."[157] Mission Innovation seeks to double public clean energy innovation investments over the next five years, work closely with the private sector to increase investment in early-stage clean energy companies emerging from government programs, and develop technology innovation roadmaps to identify innovation gaps.

The International Energy Agency (IEA) reports that there are over 100 technology innovation gaps across 35 key technologies[158] required to achieve a low-carbon transition consistent with BC's long-term GHG reduction targets. The IEA's Innovation Tracking Framework identifies key long-term "technology innovation gaps" across the energy mix that will need to be filled in order to meet long-term clean energy transition goals. Technologies that will drive affordable, low emission energy systems include RNG from wood-based feedstocks, electric vehicles, clean hydrogen production for use in natural gas distribution systems, carbon capture and storage, advanced end use appliance technologies and advanced energy efficiency and thermal energy storage. These technologies require funding to ensure they are developed, tested, optimized to local operating conditions, demonstrated and deployed to work within B.C.'s climate policy context.

6.2.2 Federal and Provincial Governments are Relying on Innovation to Meet Their Climate Objectives

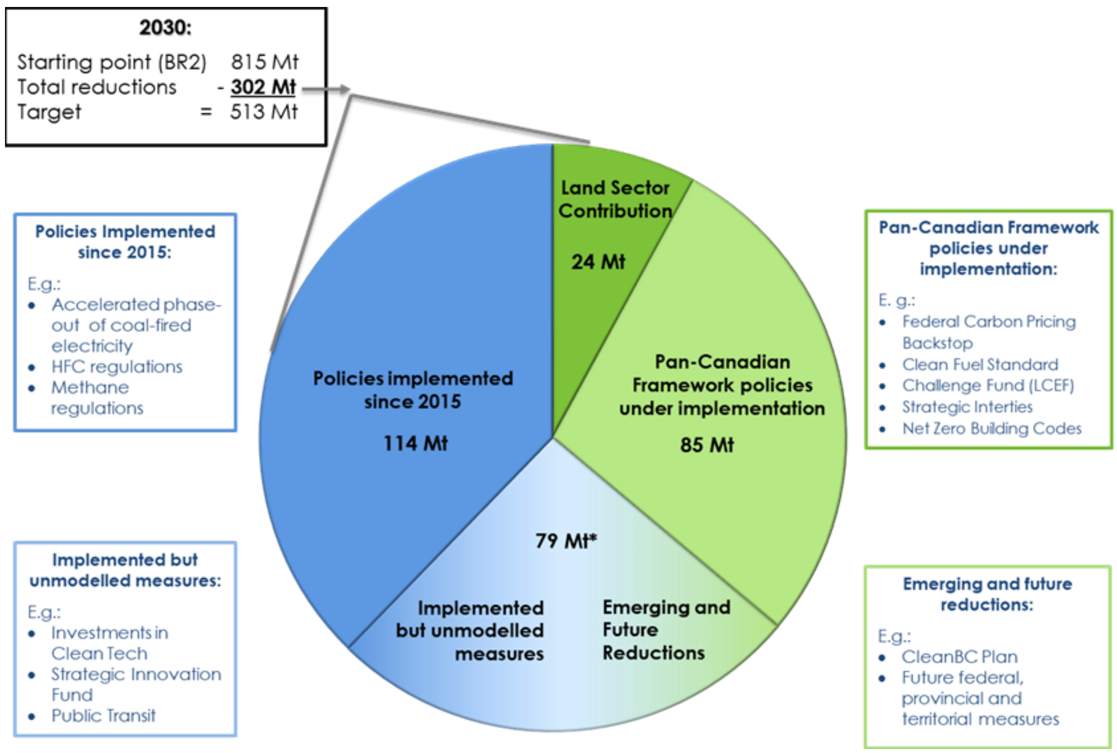
To achieve their GHG reduction targets, both the federal and provincial governments are implementing ambitious policy frameworks with explicit reference to the need for significant innovation in the marketplace.

The Pan-Canadian Framework has set a target to reduce 302 million tonnes of carbon dioxide equivalent (Mt) by 2030 (and 278 Mt net of emission reductions achieved through land-use changes). In comparison, implemented and announced federal policies are projected to only reduce 199 Mt. To make up the gap, Environment and Climate Change Canada is pointing to additional provincial plans (such as CleanBC discussed below) and unquantified measures such

157 Mission Innovation 2019: http://mission-innovation.net/about-mi/overview/.
158 IEA Innovation Tracking Framework 2018: https://www.iea.org/tcep/innovation/.

as clean tech investments and the Strategic Innovation Fund[159] (SIF) to deliver further GHG reductions. In this sense, over a quarter of the GHG reductions (79 Mt) required to achieve Canada's 2030 targets will be achieved with some combination of innovation and additional provincial policies. This is illustrated Figure C6-2 below.[160]

Figure C6-2: Measures to Achieve Canada's 2030 Emission Target



Similarly, BC has implemented and announced policies to reach the government's 2030 target, and innovation is identified as an essential underpinning for success. Policies announced in CleanBC are forecast to achieve 75 percent (18.9 Mt) of the GHG reductions required (25 Mt) by 2030. The provincial government is reviewing additional measures it can take in additional low carbon energies, waste community planning and transportation and international emission reduction opportunities to make up the gap. Advances in innovation, in areas such as low carbon energy and waste will be key to make up the gap and are within FortisBC's portfolio of activities. The BC government identifies technology strategy, R&D and clean innovation as topics of interest to drive their Strategy for a Clean Growth Future, as illustrated in Figure C6-3 below.[161]

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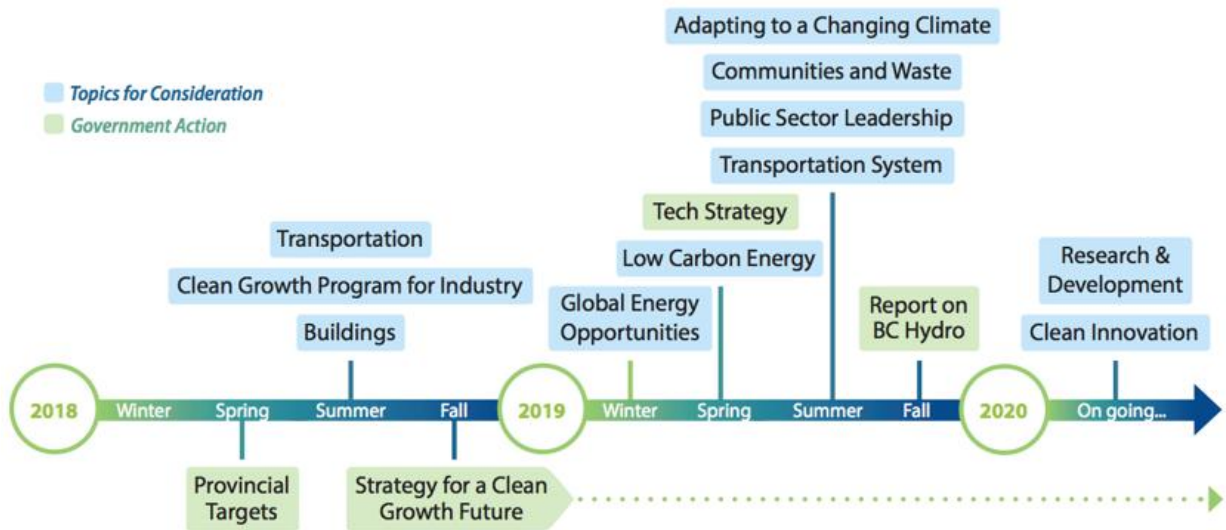
[159] "As part of its mandate, SIF will support innovative projects across all sectors that are expected to advance the development of higher-value products and inventive solutions that could mitigate environmental risks and increase global competitiveness." https://www.ic.gc.ca/eic/site/sea-ees.nsf/eng/ey00040.html.

[160] Environment and Climate Change Canada (2018). Canada's Greenhouse Gas and Air Pollutant Emissions Projects. Retrieved from: http://publications.gc.ca/collections/collection_2018/eccc/En1-78-2018-eng.pdf.

[161] Toward a Clean Growth Future for BC (2018). https://engage.gov.bc.ca/app/uploads/sites/391/2018/07/MoE-IntentionsPaper-Introduction.pdf.

Figure C6-3: Timeline, Topics and Government Actions of BC's Strategy for a Clean Growth Future



The need for innovation is highlighted by CleanBC's 15 percent renewable gas target which is forecast to achieve 75 percent (1.5 Mt) of the total emission reductions sought in the buildings sector. This target makes FortisBC's renewable gas supply and the associated generation and delivery infrastructure central components of the provincial strategy to reduce GHG emissions.

Achieving this target by 2030 will be a significant challenge for the Province, FortisBC and industry, requiring collaboration to develop the necessary policy framework, technology strategy, R&D and corresponding investment in innovation. At recent average throughput in FortisBC's gas system, 15 percent renewable gas would require approximately 30 petajoules (PJ) of renewable supply. Although FortisBC's RNG program is world leading in many respects, current renewable supply in FortisBC's system is currently 0.3 PJ, necessitating a 100-times scaling of renewable gas supply in the next 11 years.

6.2.3 Responsibility for Advancing Clean Growth Innovation Shared between Utilities, Regulators & Policy Makers

Successfully implementing clean growth innovation initiatives will require shared responsibility between utilities, regulators and policy makers. For example, meeting CleanBC's 15 percent RNG target will require FortisBC to quickly advance innovation under supportive regulatory and policy constructs developed by the BCUC and the Province.

6.3 *EVOLUTION OF INNOVATION FUNDING*

As noted in the report titled "History of U.S. Natural Gas RD&D"[162], a milestone in Research, Development and Demonstration (RD&D) for the natural gas sector was in 1976 with the

[162] Appendix C6-2: Report prepared by Ron Edelstein titled "History of U.S. Natural Gas RD&D".

formation of the Gas Research Institute (GRI). The GRI was formed to advance the state of technology to relieve the severe curtailment of service being experienced by interstate natural gas pipeline companies in the United States. The principal mission of the GRI was: "To achieve mutual benefits for the gas industry and gas consumers by planning, managing, and developing financing for an RD&D program, subject to review and approval by the Federal Energy Regulatory Commission (FERC) and, where appropriate, state regulatory commissions." Funding for the GRI RD&D program was provided by a surcharge on shipments of natural gas sold by the interstate pipelines. Gas local distribution companies would incorporate the RD&D surcharge into rates to their customers by the "filed rate doctrine" without the need for prior public utilities commission approval, as the surcharge was already approved by the FERC for interstate pipelines.

GRI had four overall objectives (programs) for its RD&D efforts -- Supply Options, End Use, Gas Operations, and Crosscutting Research. As a result of the RD&D activities, 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) occurred. GRI also performed extensive research to advance developments in Gas Operations technology. Plastic distribution pipe was researched, looking for ways to prevent slow crack growth and rapid crack propagation. Another achievement was the development of an acoustic-based plastic pipe locator that is now commercially available.

By the end of FERC-approved funding for the GRI in 2004, total RD&D funding disbursed was approximately $3.5 billion over 40 years. Gas consumer benefits over the same period were estimated at more than four times RD&D costs. The resulting benefits for shale gas RD&D and high-efficiency furnaces, water heater, boilers, and other end-use equipment continue today.

Despite these benefits, funding has not kept pace with the needs of industry. Since 2004, RD&D has been taken over by the Gas Technology Institute (GTI), which has 28 fully functioning RD&D labs. Funding peaked at over USD $200 million in the mid-1990s and halved to USD $100 million by 2016, indicating a decrease in funding when innovation continues to be required.

Over the past decade, the regulatory trend is toward increased customer funding for new innovative technologies in the natural gas and electricity industries. This is highlighted in the report titled "Regulator Rationale for Ratepayer Funded Electricity and Natural Gas Innovation" prepared by Concentric Energy Advisors.[163] Outlined in the report are some of the reasons for the trend in utility led, ratepayer funded innovation, including:

> …. 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.[164]

[163] Report prepared by Concentric Energy Advisors titled "Regulator Rationale for Ratepayer Funded Electricity and Natural Gas Innovation" for the Canadian Gas and Canadian Electricity Association, April 2018".

[164] Page 3 of Report.

The report notes the benefits of Innovative technology programs for both customers and companies, including:

> 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 time lapsed, but important direct benefits for customers by improving the way their customers use energy, control their energy use and derive benefit from it.[165]

The report concludes that the factors driving the interest in funding innovation have taken hold among global economic regulators, and that the responsibility for innovation is shared by the utilities, regulators and other policy makers:

> 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. 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.[166]

Three case studies illustrating the importance of collective responsibility in advancing innovation are discussed below.

6.3.1 Case Study 1: United Kingdom's RIIO Framework

Ofgem, the regulator of energy network companies in the United Kingdom (UK), implemented the *Revenue using Incentives to deliver Innovation and Outputs Framework* (RIIO-1) in 2013. The RIIO Framework is the regulatory framework designed to cover utility costs while encouraging them to "play a full role in delivery of a sustainable energy sector" and "deliver value for money network services for existing and future consumers."[167] In addition, the core objectives of rate setting such as stimulating efficient operations and capital expenditures, RIIO-1 introduced specific objectives to integrate innovation as a core business objective and to improve the cost-efficiency of shifting to sustainable energy solutions.

Recognizing that the regulatory framework must evolve to serve customers while driving the shift to a sustainable energy sector, Ofgem introduced a renewed rate making mechanism that would allow for ratepayer funded innovation schemes. This goal was to reward longer-term decision-making by regulated utilities to drive a sustainable, reliable energy sector and deliver value for money for energy consumers. Ofgem identified the need for specific innovation

[165] Page 3 of Report.

[166] IBID. p.3.

[167] Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking- A specific innovation stimulus. (2010) Retrieved from https://www.ofgem.gov.uk/sites/default/files/docs/2009/12/et-innovation.pdf.

stimulus within the time-limited carbon reduction goals of the UK government within the next 10 years.

Under RIIO-1, 720 million Great Britain Pounds (GBP) of ratepayer funded innovation was opened to the gas and electric sectors from 2013 to 2023 with GBP 225 million being awarded over first 5 years. Funding is allocated through three traunches, the Network Innovation Allowance (NIA), the Network Innovation Competition (NIC) and the Innovation Roll-Out Mechanism. The NIA provides GBP 61 million annually to fund small scale research, development and demonstration projects that covers all types of innovation including commercial, technological and operational.[168] The allowance can fund a wider range of projects as its focus expands beyond potential low carbon and environmental benefits.[169]

The NIC is focused on funding development and demonstration of new technologies, operating and commercial arrangements that provide environmental benefits, reduce costs and maintain security of supply in the UK. In the gas sector, annual funding of GBP 20 million is available and has supported, for example, hydrogen blending and artificial intelligence projects under the NIC. The Innovation Roll-Out Mechanism provides funding for the rollout of successful innovations in cases where existing price controls will not fund it.

The Low Carbon Networks Fund (LCNF), a ratepayer funded innovation fund established by Ofgem, pre-dated the RIIO-1. Ofgem commissioned an independent evaluation of the LCNF that found that the "*LCFN succeeded in encouraging [utilities] to innovate and served to move the level of innovation from a 'low' base to a 'moderate' level*." Further, the LCNF "*encouraged [utilities] to include innovation as core business*" with "*current benefits estimated to be approximately one third of the total funding cost*" and "*the future net benefit… is significant and is estimated to range from 4.5 to 6.5 times the cost of funding the scheme*."[170]

Ofgem is currently consulting on the RIIO-2 Framework that will begin in 2021 for gas utilities and 2023 for electric utilities. In their Decision on the Review of Innovation Funding, Ofgem stated (at p. 26):

> Innovations by network companies are making their way into day-to-day use and are delivering financial and carbon benefits. The future consumer benefit, which is expected to comfortably exceed the scheme costs, provides a strong case for continuing innovation funding to drive beneficial innovations by the network companies that would not happen in its absence.[171]

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[168] The Network Innovation Review: Our Policy Decision (2017). p. 9. https://www.ofgem.gov.uk/system/files/docs/2017/03/the_network_innovation_review_our_policy_decision.pdf.

[169] Gas Network Innovation Allowance Governance Document (2015). p.6. https://www.ofgem.gov.uk/sites/default/files/docs/2015/04/gas_nia_v2_-_final_clean.pdf.

[170] Reviewing the benefits of the Low Carbon Network Fund and the governance of the Network Innovation Competition and the Ntework Innovation Allowance (2015). p.3. https://www.ofgem.gov.uk/sites/default/files/docs/151217_-_two_year_review_open_letter_au.pdf.

[171] Ofgem, (2017). The Network Innovation Review: Our Policy Decision https://www.ofgem.gov.uk/system/files/docs/2017/03/the_network_innovation_review_our_policy_decision.pdf.

6.3.2 Case Study 2: New York State's Millennium Fund

New York state's utility regulator, the New York Public Service Commission (NYPSC), has taken decisive actions to support customer-funded RD&D projects in the state's energy industries. In 2000, the NYPSC approved a surcharge intended to fund medium to long term R&D by natural gas local distribution companies. The NYPSC directed funds to distribution activities and to improving end-use appliances in an effort now known as the Millennium Fund. An example Millennium Fund project is Consolidated Edison's proposal to repair gas distribution lines through the deployment of trenchless technologies. These gas R&D projects have been estimated to have a 3:1 benefit-to-cost ratio.[172]

The "Reforming the Energy Vision" (REV) proceedings began in 2014 with the goal of using technology and business model innovation to integrate distributed energy resources to reduce carbon emissions and enhance system reliability. In line with REV objectives, the NYPSC has approved customer funded demonstration projects and set out eight criteria, including customer engagement, scalability and value distribution, to evaluate demonstration proposals. The project cost recovery of REV demonstration projects is capped at $10 million per year. In a recent proposal, Consolidated Edison proposed to create a Gas Innovation Program to evaluate the scalability of clean heating technologies through various business model tests. This is a part of a greater demonstration project designed to contribute to state environmental goals and alternative resource exploration.[173]

6.3.3 Case Study 3: Ontario's Low Carbon Initiative Fund

In late 2017, Union Gas Limited, in its 2018 Cap and Trade Compliance Plan[174] proposed a Low Carbon Initiative Fund (LCIF). Although the LCIF application has been on hold, it provides a compelling argument for the importance of utility investment in innovation.

Union Gas sought approval of up to $2 million LCIF funding annually in order to explore, identify and develop abatement concepts to the point of commercialization (e.g., ground/air source heat pumps, micro-generation, building skins, hydrogen and power-to-gas). The LCIF was intended to ensure a stable and predictable level of funding so that Union Gas could proactively identify and develop abatement ideas for GHG emissions reduction to consistently feed and move through the development process, with the goal of realizing abatement over the longer term.

Union Gas proposed that the cost of the LCIF be recovered from customers as customers would benefit from the innovative technologies pursued. Customer benefits included abatement which can reduce customers' carbon and energy costs, as well as increasing customer choice for affordable energy options. Stakeholders generally supported the LCIF with differing positions on the appropriate level of funding. However, the cancellation of the Ontario Cap and Trade program in 2018 by the provincial government led to the suspension of the Ontario Energy

[172] Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation (2018). p. 16. https://ceadvisors.com/wp-content/uploads/2018/05/Concentric-Final-Innovation-Report-4.23.18.pdf.
[173] Ibid.
[174] Exhibit 3, Tab 4, Section 1, Tab 5, Section 4.2.

Board's review of Union Gas' 2018 Cap and Trade Compliance Plan where approval of the LCIF was requested. As a result, Union Gas' proposed LCIF is on hold indefinitely.

Despite the cancellation of the Cap & Trade program, climate policy and the importance of innovation remain important topics in Ontario. In November 2018, the Advisory Committee on Innovation submitted recommendations to the Chair of the OEB on actions to support innovation in Ontario's energy sector. The Committee was tasked with identifying actions that a regulator can take that will support and enable cost effective innovation, grid modernization and consumer choice to help inform regulatory policy development.

The OEB announced a stakeholder session on January 16, 2019 to discuss the recommendations made by the Advisory Committee on Innovation and inviting comments on prioritization, interdependencies and gaps. Amongst the recommendations was a recommendation to "Consider timely funding mechanisms to encourage utility innovation that provides near term customer benefits."

> 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.[175]

6.4 *THE FUND COMPLEMENTS CURRENT INNOVATION ACTIVITIES & ADDRESSES CRUCIAL GAPS*

This section discusses how the Fund complements the Companies' current innovation activities and fills the innovation gaps needed to be successful.

FortisBC's three main areas of innovation related to adapting climate policy are described below, along with the innovation gaps that will be addressed by the Fund.

6.4.1 Innovative Technologies

FEI's[176] Innovative Technologies program serves an important function in achieving DSM objectives to increase the efficient use of energy; however, the Innovative Technologies program is restricted from allocating funds for initiatives designed to reduce GHG emissions, and investment is limited to the building and industry sectors.

Since 2010, FEI has been providing DSM funds to evaluate innovative technologies. The primary objective is to identify pre-commercial and commercially available technologies that are not yet widely adopted in British Columbia, and which are suitable for the development of, or

[175] Page 13 of report.
[176] FBC has applied to the BCUC for a similar program as FEI's Innovative Technologies.

inclusion in, the portfolio of ongoing DSM program offerings. This is accomplished through pilot and demonstration projects, pre-feasibility studies and evaluations to validate manufacturers' claims related to equipment and system performance. Those technologies must meet the definition of a technology innovation program as set out in the Demand-Side Measures Regulation and its cost-effectiveness is evaluated as part of the DSM portfolio as a whole.

Although approved funding exists for Innovative Technologies, additional funds are required for activities outside of DSM that are designed to adapt to government de-carbonization policies. The key difference between a DSM and a non-DSM innovative activity is whether the technology can directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy. If the technology does, then the technology may be eligible to receive funding from the Innovative Technologies program. If it does not, then no DSM related funding can be provided, even though the activity may reduce GHG emissions.

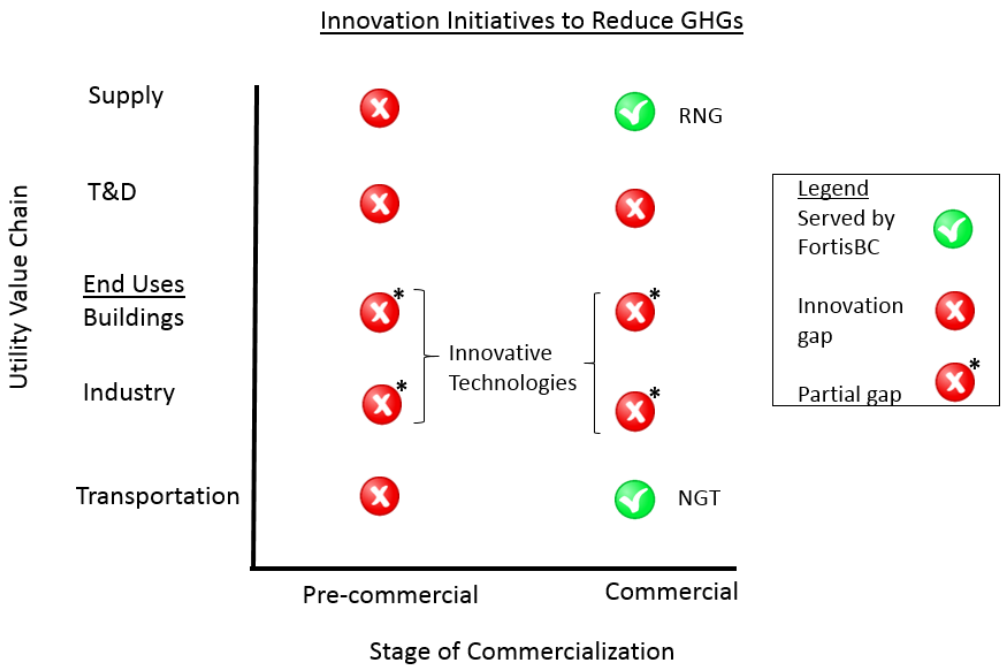
6.4.2 Natural Gas for Transportation and Renewable Natural Gas

FortisBC's NGT and RNG programs advance the market adoption of commercial products that reduce GHG emissions in accordance with the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR). However, these programs cannot fund pre-commercial initiatives and investment is limited to RNG & NGT specific activities. For example, FEI has only provided incentives for vehicles that have original equipment manufacturer (OEM) support as this ensures our customers have the requisite support to operate their businesses. Pre-commercial technologies would not meet this critical OEM support threshold.

6.4.3 Gaps to be Addressed by the Fund

Figure C6-4 below summarizes the innovation gaps identified above:

Figure C6-4: Innovation Gaps to be Addressed by the Fund



In the legend to the figure above, a partial gap refers to activities associated with Innovative Technologies in order to acknowledge that energy efficiency initiatives can reduce GHG emissions (although not necessarily). Notwithstanding the fact that GHG reductions may be a by-product of energy efficiency, Innovative Technologies cannot invest in GHG reduction initiatives. Hence, these segments are deemed to have a partial gap.

When viewed from the lens of achieving GHG reductions through innovation, FEI's NGT and RNG programs serve the commercial needs of the supply and transportation segments of the utility value chain. In contrast, the entire value chain is underserved in pre-commercial initiatives, while transmission and distribution (T&D), buildings and industry are underserved in commercial initiatives.

The Fund will address the innovation gaps by focusing on GHG reduction activities that:

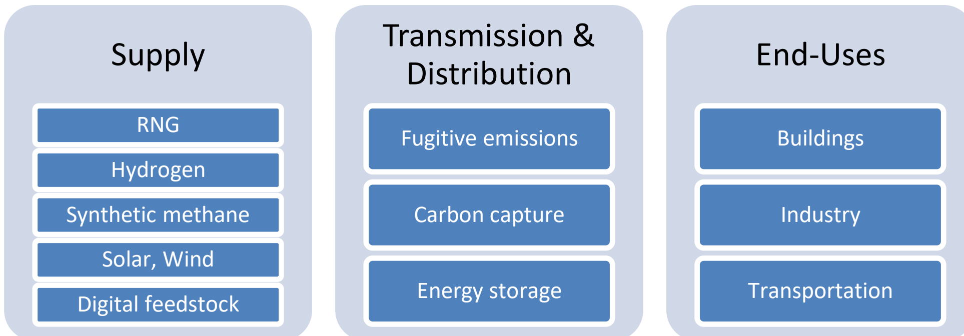
- cover the entire energy utility value chain;
- are outside of DSM that reduce GHG emissions;
- relate to pre-commercial and commercial activities; and
- are supported by predictable funding levels.

This is described further below.

6.4.3.1 Spanning the Entire Utility Value Chain

Climate solutions are required all across the energy utility value chain including supply, transmission and distribution and end-uses related to our natural gas and electric businesses. These include both DSM and non-DSM activities. The following graphic displays the utility value chain and related innovation categories relevant to FortisBC.

Figure C6-5: Climate Solutions Required Across the Utility Value Chain



6.4.3.2 Activities Outside DSM that Reduce GHG Emissions

The definition of activities outside of DSM provided below provides a means of distinguishing these activities from those that Innovative Technologies currently funds in accordance with the Demand Side Measures Regulation.

In relation to the Fund, activities outside of DSM, refers to a rate, measure, action or program undertaken:

(a) To develop a technology, a system of technologies, a process, a design or a facility that is

I. Not commonly used in British Columbia

II. The use of which could directly or indirectly result in reductions of GHG emissions

III. The use of which could promote the adoption and commercialization of low carbon solutions

(b) To do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) To gather information about a technology, a system of technologies, a building design or an industrial designed referred to in paragraph (a)

But does not include:

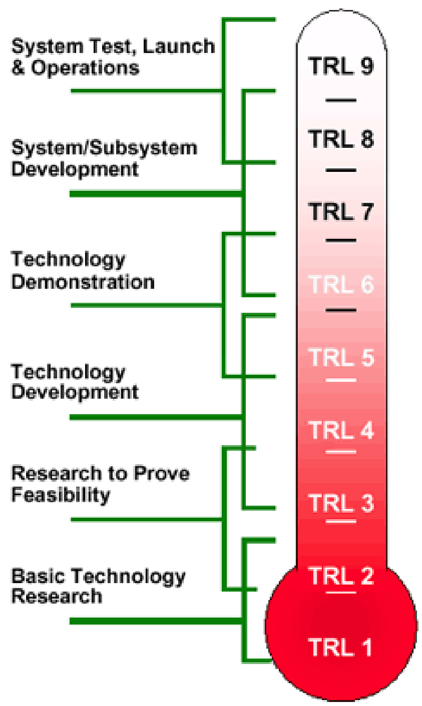
(b) A rate, measure, action or program undertaken to

l. conserve energy or promote energy efficiency that is already eligible for DSM funding

6.4.3.3 Pre-Commercial & Commercial Activities

Figure C6-6 below shows the broadly-accepted technology readiness levels (TRL) for innovation related activities starting at Basic Technology Research (TRL 1-2) and proceeding through to System Test, Launch & Operations (TRL 8-9).

Figure C6-6: Levels of Technology Readiness Activities[177]



The Fund will advance initiatives that fall within the range of 'Research to Prove Feasibility' and 'System Test, Launch and Operations' levels of technology readiness. Basic technology research is outside the Fund's commercialization focus and it will rely on industry participants such as academic institutions to advance these activities. The Companies will add value to the commercialization process once technologies are ready for feasibility research.

6.4.3.4 Predictable Funding Levels

The table below summarizes the requirements for predictable funding in non-DSM, pre-commercial, innovative activities covering the entire value chain. The gas requirement is $4.9 million while electric is $0.5 million. Details regarding the investment areas are available in Appendix C6.

[177] https://web.archive.org/web/20051206035043/http://as.nasa.gov/aboutus/trl-introduction.html.

Given the evolving nature of the Fund, FortisBC anticipates that flexibility will be required to allocate funds from one investment area to another at its discretion.

Table C6-2: Forecast Clean Growth Expenditures in 2020

Stage of Value Chain	Investment Area
Supply	Blending Hydrogen
	Renewable Natural Gas
	Digital Natural Gas Feedstock
Transmission & Distribution	Fugitive Emissions Reduction
	Carbon capture
Energy Use	Natural Gas for Transportation
	Hydrogen for Transportation
	Electric Vehicles and Charging Stations
	End Use Technologies
Supply, T&D & End Use	Natural Gas Innovation Fund

6.5 *STRUCTURE OF THE FUND*

This section describes the Fund's robust framework including the purpose, objectives and guiding principles, the stages of project development, the governance structure, and the reporting and accounting treatment.

6.5.1 Purpose, Objectives & Guiding Principles

The purpose of the Fund is to ensure there are opportunities for FortisBC to participate and thrive in an evolving climate policy context by continuing to utilize its natural gas and electric delivery systems. The Fund's main objective is to accelerate the pace of clean energy innovation to achieve performance breakthroughs and cost reductions to provide widely affordable, safe and reliable clean growth solutions for our customers (per Canada's commitment to Mission Innovation).

The following guiding principles underpin the design and operation of the Fund:

1. **Ensure transparency**

   The Companies will be accountable to the BCUC in its administration and oversight of the Fund.

2. **Pursue innovations with strong customer benefit**

   Focus on opportunities expected to deliver customer benefit. In addition to successfully responding to climate policy aimed at GHG reductions, benefits will include cost effectiveness, safety and reliability.

3. **Use a portfolio approach to diversify risks**

   Adopting a portfolio approach to selecting innovative technologies will help to diversify risks and stay abreast of the different technologies under development in the marketplace.

4. **Leverage partnerships**

   Leveraging partnerships with other organizations including governments, utilities, associations and innovative technology firms will provide greater access to capital, expertise and opportunities available.

5. **Coordinate innovation centrally to ensure maximum value**

   FortisBC will coordinate and manage the different innovation opportunities it is pursuing to achieve value and create synergies between initiatives where possible. Funds collected from customers not invested will be returned to customers at the end of the Proposed MRP terms.

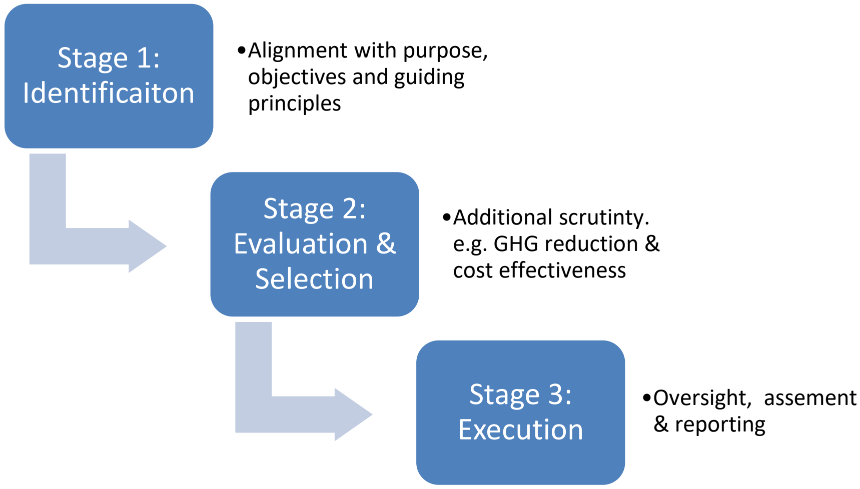
6. **Optimize FortisBC's regulated assets and expertise**

   Focus on activities that ensure FortisBC's natural gas and electric assets continue to be fully utilized.

6.5.2 Stages of Project Development

As seen in Figure C6-7, innovative projects will be developed in three stages: identification, evaluation, and selection and execution.

Figure C6-7: Stages of Innovative Project Development



In the identification stage, projects aligned with the Fund's purpose, objectives and guiding principles will be identified by FortisBC experts in collaboration with an external advisory group (further details found in the Governance section below).

Projects satisfying these preliminary identification screening criteria will advance to the Evaluation & Selection stage for deeper scrutiny subject to the following criteria:

- GHG reductions and air quality improvement relative to existing technologies;
- Potential for market adoption based on economic and technical feasibility; and
- Impact on FortisBC customers including cost effectiveness, safety and reliability.

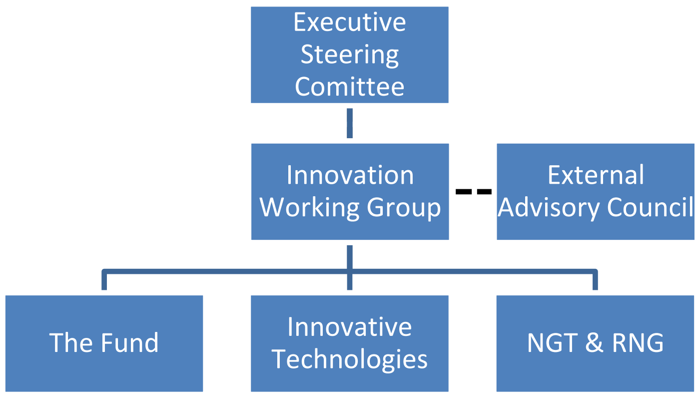
Proposals which receive final approval for funding will proceed to the Execution stage for project management, assessment and reporting by FortisBC. Out of the assessment process, a range of outcomes is to be expected. For example, the initiative may indicate potential and require additional exploration. In this scenario, a new, incremental initiative would re-start the 3 stage process to secure incremental funding. Likewise, an initiative may indicate little potential and consequently would cease at its conclusion. The range of outcomes will be communicated to the BCUC in the Companies' annual reporting.

6.5.3 Governance Structure

The Companies will ensure that the governance structure reflects the guiding principles of the Fund. FortisBC will establish two separate bodies with oversight of the Innovation Fund. First, an Innovation Working Group (the Group) will be responsible for the Identification, Evaluation and Selection, and Execution stages of projects. The Group will be comprised of staff from both the gas (FEI) and electricity (FBC) utilities to provide subject matter expertise from the supply, transmission and distribution and end use areas of FortisBC. The Group will foster collaboration and synergies amongst Innovative Technologies, NGT and RNG, and the Fund. Second, an

Executive Steering Committee (the Committee) will be established to provide the strategic direction of the Fund. The Committee will be comprised of senior staff representing both FEI and FBC. Additionally, FortisBC proposes to establish an External Advisory Council made up of stakeholders to provide insight and feedback on the Companies' innovative initiatives on a periodic basis.

Figure C6-8: Governance of the Fund



6.6 *REPORTING & ACCOUNTING TREATMENT*

The Companies will provide an annual update on the progress on approved projects as part of its Annual Review process.

FortisBC proposes customer RD&D funding annually that is expected to generate approximately $4.9 million for FEI and approximately $0.5 million FBC (about half of those amounts in 2020 to provide sufficient time to ramp up activities). To achieve this, the Companies propose to use a basic charge rate rider in lieu of a volumetric rate rider so that all customers fund Innovation equally. Additionally, the Companies have calculated the rider below and propose to maintain it at the proposed level through the term of the Proposed MRP. Annual spending is not expected to exceed the approved annual funding (plus any amounts carried forward from prior years) unless additional funding is approved by the BCUC. The funds collected from customers less the amounts expended through the governance process set out above will be recorded in a deferral account and carried through the term of the Proposed MRPs, with the cumulative unspent funds at the end of the Proposed MRPs returned to customers.[178]

The basic charge rider for FEI and FBC equals $0.40 and $0.30 month[179] respectively. The following calculations determine the rider.

[178] Deferral account details included in Section C5.
[179] Will be pro-rated for customers that pay basic charges on a basis other than monthly.

Table C6-3: Calculation of Funding Levels for FEI and FBC

	FEI	FBC
Basic Charge Rider per Month	$0.40	$0.30
Months	12	12
Forecast of Average Customers 2020 (FEI is non-bypass)	1,036,640	140,460
Anticipated Funding Levels	$4.9 million	$0.5 million

Recognizing that the Companies will only need half of the annual funding in 2020 as activities ramp up, the riders will not be implemented until July 1, 2020.

6.7 *CONCLUSION*

In summary, the responsibility for advancing clean growth innovation to meet BC's climate objectives is shared between utilities, regulators and policy makers. The Fund will assist FortisBC in addressing the expectation to reduce emissions and support the transition to a lower carbon economy while maximizing the use of its energy delivery systems for the benefit of its customers.

7. SERVICE QUALITY INDICATORS

7.1 *INTRODUCTION*

In this section, FortisBC summarizes its proposed Service Quality Indicators (SQIs) for FEI and FBC. A full discussion of the proposed SQIs is included in Appendix C5-1 and C5-2 to this Application.

SQIs form the basis of determining a utility's quality of service and represent a broad range of business processes that are important elements to the customer experience. Under the Current PBR Plans, SQIs are used to monitor the Utilities' performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers. FortisBC proposes to continue this approach.

The BCUC approved a balanced set of SQIs for the Current PBR Plans covering safety, responsiveness to customer needs, and reliability for FEI and FBC. For FEI, nine of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the BCUC in Order G-14-15. Four of the SQIs are for information only, and as such do not have benchmarks or performance ranges. For FBC, eight of the SQIs have benchmarks and performance ranges set by a threshold level, also approved by the BCUC. Three of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

FortisBC believes the current suite of SQIs for FEI and FBC have been appropriate and useful in monitoring the Utilities' performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality. For the Proposed MRPs, FortisBC reviewed the current SQIs for their continued appropriateness in measuring service quality and for the level of the benchmarks and thresholds for each metric. Based on this review, FEI and FBC propose SQIs that build on the experience gained with updates and modifications where required. FEI and FBC propose to replace the Informational Indicator of Telephone Abandonment Rate with another Informational Indicator, Average Speed of Answer (ASA). FBC also proposes to report on a new informational SQI, called "Interconnection Utilization", to measure the reliability of service for Wholesale Municipal customers.

Similar to the Current PBR Plans, FEI and FBC will report each year's results to the BCUC and stakeholders at the Annual Review to allow a comparison of the Companies' SQI performance against the benchmark targets and the thresholds for each of the SQIs. Also consistent with the Current PBR Plans, failure to meet SQI benchmark thresholds, if determined by the BCUC after further process to be considered a serious degradation of service quality in whole or in part due to the actions (or inactions) of the Companies, may result in a reduction to the share of earnings sharing retained by the Companies, up to a maximum reduction to reflect a 60 percent share to the customer (i.e., penalty of 10 percent of the earnings sharing earned to the Companies), instead of the standard 50 percent.

In the following two sections, FortisBC summarizes the SQIs and benchmarks and thresholds used for the Current PBR Plans and the proposed SQIs and the benchmarks and thresholds for the Proposed MRP for FEI and FBC, respectively.

7.2 *FEI'S PROPOSED SERVICE QUALITY INDICATORS*

For the Proposed MRP, FEI reviewed the existing SQIs and believes they remain appropriate to ensure that service quality to our customers is maintained throughout the term of the Proposed MRP. FEI proposes to change the benchmarks of some SQIs, recognizing their recent historical performance. The following table provides a comparison of FEI's current and proposed SQIs. Shaded areas reflect changes from the current SQIs. Proposed changes to SQIs are highlighted in green in the table, and discussion of the changes is provided below the table.

Table C7-1: Comparison of FEI Current and Proposed SQIs

			Current		*Proposed*	
Indicators with Benchmarks and Thresholds			Benchmark	Threshold	Benchmark	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

7.2.1 Public Contacts with Gas Lines

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 FEI believes is sustainable, FEI proposes to lower the benchmark from 16 to 8.

Table C7-2: FEI Results during the Current PBR Plan for Public Contact with Gas Lines

	2014	2015	2016	2017	2018
Public Contact with Gas Lines – three year rolling average	11	9	9	8	8
Public Contact with Gas Lines – annual	9	8	8	9	8

The results from 2014 to 2018, shown in Table C7-2 above, 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 annual 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 also to revise the basis for the actual results reported from the current three-year rolling average approach to a current year approach. A current year approach is easier to understand and provides a clearer indicator of FEI's performance in a given year as opposed to an approach based on a three-year rolling average.

FEI proposes to lower the threshold to 12 to be reflective of historical performance observed.[180] While performance has improved in recent years, historical results have been higher and provide an objective basis to set a satisfactory performance range.

7.2.2 Billing Index

FEI proposes to continue to report on the Billing Index as FEI believes that customers value complete, timely and accurate bills. Reflective of the recent historical performance and efficiencies achieved by FEI in producing bills, FEI proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0.

Table C7-3: FEI Results during the Current PBR Plan for Billing Index

Description	2014	2015	2016	2017	2018
Billing Index	0.89	1.06	0.57	0.75	2.63

The results from 2014 to 2018 shown in Table C7-3 above have been better than the benchmark approved by the BCUC. No significant billing issues have arisen over the period.

[180] Annual results reported; 2010 – 18; 2011 – 16; 2012 – 13; 2013 – 10.

7.2.3 Telephone Abandonment Rate

FEI proposes to replace the Informational Indicator of Telephone Abandonment Rate 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 interactive voice response or 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 on the trends in the Telephone Abandonment Rate with any certainty.

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 C7-4: 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

7.2.4 GHG Emissions

Even though total GHG emissions is not an approved SQI, FEI has been reporting total GHG emissions as part of the Annual Review process. This requirement to report total GHG emissions results from the BCUC's decision on FEI's Annual Review for 2015 Delivery Rates. In the decision in that proceeding, the BCUC directed FEI to provide estimated annual GHG emissions reported to the Ministry of Environment in FEI's Annual Reviews.

As the total GHG emissions measure is very broad, the Companies do not believe that it is necessarily a meaningful measure to focus on as an SQI. Instead, to manage and reduce GHG emissions, FortisBC's has proposed its inclusion in the Targeted Incentives section (see Section C8 Incentives). Additionally, the Companies recently published a new Sustainability Report[181] which will be published annually, and includes GHG emissions information. The Sustainability

[181] For a copy of 2017 FortisBC Sustainability report, refer to https://www.fortisbc.com/about-us/sustainability.

Report provides added context to GHG emissions figures and is therefore a more suitable format for reporting GHG emissions. As a result, FEI will be discontinuing reporting of total GHG emissions as part of the Proposed MRP.

A full discussion of the proposed SQIs is included in Appendix C5-1 to this Application.

7.3 *FBC'S PROPOSED SERVICE QUALITY INDICATORS*

For the Proposed MRP, FBC reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to our customers is maintained throughout the term of the Proposed MRP. For some SQIs, FBC proposes to change their benchmarks and thresholds, recognizing their recent historical performance. The following table provides a comparison of FBC's current and proposed SQIs. Proposed changes to SQIs are highlighted in Green in the above table and a discussion of each change is provided below the table.

Table C7-5: Comparison of FBC Current and Proposed SQIs

			Current		*Proposed*	
Indicators with Benchmarks and Thresholds			Benchmark	Threshold	Benchmark	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

7.3.1 First Contact Resolution

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 deliver this customer experience. In increasing the FCR threshold, FBC is aligning it more closely to past performance.

7.3.2 Billing Index

FBC proposes to continue to report on the Billing Index as FBC believes that customers value complete, timely and accurate bills. Reflective of the recent historical performance and efficiencies achieved by FBC in producing bills, FBC proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0.

Table C7-6: FBC Results during the PBR Plan for Billing Index

Description	2014	2015	2016	2017	2018
Billing Index	2.34	0.39	0.57	0.15	0.29

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 FBC believes that customers value complete, timely and accurate bills. Reflective of the recent historical performance and efficiencies achieved by FBC in producing bills, FBC proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0.

7.3.3 Meter Reading Accuracy

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 from 97 percent and to increase the threshold by one percent, to 95 percent from 94 percent.

Table C7-7: FBC Results during the PBR Plan for Meter Reading Accuracy

Description	2014	2015	2016	2017	2018
Meter Reading Accuracy	98%	96%	99%	99%	99%

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.

7.3.4 Telephone Abandonment Rate

Similar to FEI discussed earlier, FBC proposes to replace the Informational Indicator Telephone Abandonment Rate with another Informational Indicator, Average Speed of Answer.

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 C7-8: 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

7.3.5 System Average Interruption Duration and Frequency Indexes

FBC proposes to continue to report SAIDI and SAIFI. To adjust for the influence of the Outage Management System (OMS) on the reported results, FBC proposes to update the existing SAIDI and SAIFI three year rolling average benchmark. For the Proposed MRP, starting in 2020, FBC will have three full years of SAIDI and SAIFI results available (i.e., 2017, 2018, 2019) incorporating the impact of the OMS. As the 2019 SAIDI and 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 Proposed 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 approach. A current year approach is generally easier to understand and a clearer indicator of FBC's performance in a given year than an approach that is based on a three-year rolling average.

In conjunction with this change, FBC proposes to change the thresholds to reflect the annual results, consistent with the basis for the actual results. Similar to the approach used to determine the existing thresholds, the proposed thresholds will be based on statistical analysis (i.e., standard deviation) of the SAIDI and SAIFI historical results.

7.3.6 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 SQI to monitor the level of service provided to the municipal wholesale customers (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 wholesale customers. There are twelve points of interconnection combined between the four customers as shown in the table below:

Table C7-9: 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:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

For 2018, these interconnection points were providing service for 105,082 hours out of the available 105,120 hours, at an Interconnection Utilization performance level of 99.96 percent. Historical results from 2014 to 2018 have been relatively stable averaging 99.97 percent over the period.

Table C7-10: 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%

The proposed new metric was discussed with the BCMEU prior to including it in this filing. The BCMEU was supportive of the proposed metric, noting its simplicity and that it allows the municipal customers to benchmark their service against other FBC customers.

A full discussion of the proposed SQIs is included in Appendix C5-2 to this Application.

8. INCENTIVES

8.1 *INTRODUCTION*

As discussed earlier in Section B2 – Rate Setting Background, both FEI and FBC have had successful multi-year rate plans. Although these rate plans have allowed some flexibility in bringing forward pre-defined initiatives through the Annual Review processes, the plans have been mainly focused on achieving cost efficiencies and reducing regulatory burden. While this focus led to cost savings for ratepayers, a more targeted approach is now required to be added to address the longer-term challenges and opportunities facing FortisBC; one that will foster innovation, and encourage the achievement of targeted incentives.

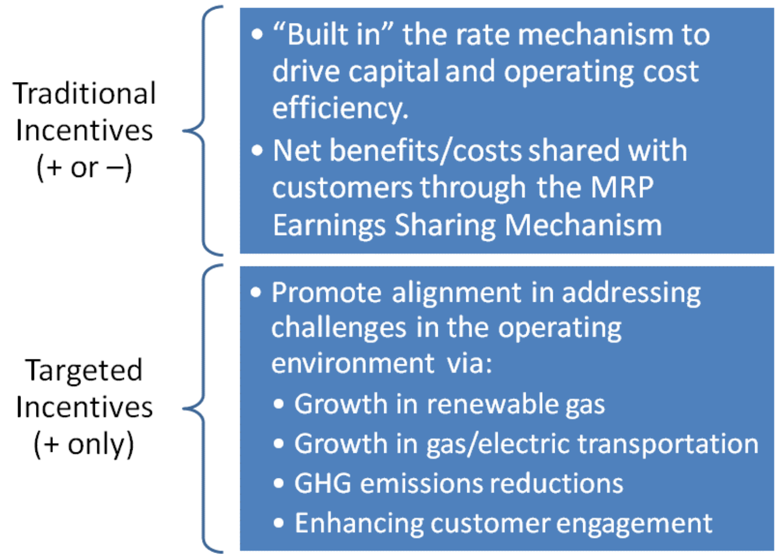
As also discussed in Section B2, regulators in other jurisdictions are increasingly recognizing the benefit of moving towards the inclusion of targeted incentives to promote innovative solutions to traditional utility challenges in their jurisdictions. For instance, as indicated in the paper by Dr. Jeff Makholm published in the Electricity Journal, many U.S. based utilities are moving beyond the mere cost reduction perspective to incentive regulation and are embracing other incentive frameworks that can better promote innovation and prepare the utilities for the "Utility of Future".[182]

For the Proposed MRP, FortisBC believes that adding a targeted approach to performance incentives is appropriate and beneficial. FortisBC proposes to continue with traditional incentives that are inherent in index-based capital and operating costs and that have worked successfully in the past. FortisBC proposes adding targeted performance incentives that bring focus to addressing some of the challenges and opportunities in the operating environment.

Figure C8-1 below summarizes the different types of incentives proposed for this MRP.

[182] See Appendix C4-1: Makholm, Jeff D. The rise and decline of the *X factor* in performance-based electricity regulation. The Electricity Journal. 2018.

Figure C8-1: Incentives for the Proposed MRP



Following is a discussion of the two different components of the broader and enhanced incentive approach.

8.2 *TRADITIONAL INCENTIVES*

The traditional incentives are those contained in the Proposed MRPs that flow from the overall rate plan (excluding the targeted incentives discussed below) into the Earnings Sharing Mechanism (ESM). An ESM is a regulatory tool in a rate setting plan that is designed to enhance the alignment between customer and company interests and share the risks and benefits of the plan. An ESM is also put in place to mitigate against unintended results of a new plan, such as excessive utility gains or losses. An ESM is typically a backward-looking sharing mechanism in which a rate adjustment is provided if the actual earnings fall below or exceed a certain threshold.

The 2014 PBR Decision approved an ESM where gains and losses are shared equally between the Companies and customers, stating that.

> **The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers.** In our view, the inclusion of an earnings sharing mechanism balances the interests of the customer and the utility. That is, to the extent that there are gains or losses relative to the approved ROE, the fact that they are shared on a 50:50 basis between the ratepayer and the utility is reasonable. The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the course of this PBR, generate efficiency savings resulting in earnings, which allow them to exceed the approved ROE return. Fortis has proposed that these savings be shared. To deny the

customer the opportunity of sharing these savings would not be in their interest.[183]

Similar to the Current PBR Plans, FortisBC proposes the continuation of incentives designed to encourage a continued focus on efficient operations. FortisBC's focus is not only on reducing costs, but on maximizing efficiency more broadly.

Through the ESM (calculated as 50 percent of the ROE variance from allowed) FortisBC will have incentive to:

1. Contain annual index-based O&M expenditures to a level at or below that calculated under the gross O&M per customer amount; and
2. Contain Regular capital spending[184] at the approved level or, in the case of FEI's Growth capital, at or below the amount set through the index-based unit cost.[185]

FortisBC is returning to the widely-accepted method of calculating earnings sharing, which is a straight-forward percentage (in this case 50 percent) of variances from the allowed rate of return on equity. This is the same method as was proposed by FortisBC for its Current PBR Plans, what was approved in FEI's 2004-2009 PBR, in FBC's 2007-2011 PBR, and in other Canadian jurisdictions including Ontario (for natural gas utilities) and Quebec (for HQD). In this case, the regulated return on equity to which the earnings sharing applies excludes any targeted incentives (discussed further below in Section C8.3).

FortisBC believes a return to the simplified calculation provides:

- greater transparency;
- increased simplicity in the MRP design; and
- incentive and flexibility to implement capital plans efficiently.

8.3 *TARGETED INCENTIVES*

To increase the focus of the Companies on the challenges and opportunities that it faces in its operating environment, FortisBC believes that targeted incentives in emerging and strategic areas are appropriate and in the public interest. This approach is consistent with the observation that utility regulators are increasingly turning their attention to new aspects of utility performance, such as customer engagement (including tools to empower customers to better manage their bills), environmental impacts, and clean energy policy goals.[186]

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183 Order G-138-14, page 124 and G-139-14, pages 120-121.

184 Regular capital refers to capital that is part of the 5-year forecast and/or part of FEI growth capital. It excludes Major Projects and capital that is subject to flow through treatment.

185 The ROE impact of variances in Regular capital expenditures will be reflected in variances in depreciation, interest, taxes and ROE.

186 Appendix C8, Utility Performance Incentive Mechanisms, A Handbook for Regulators, March 9, 2015.

Both FEI and FBC have been developing a number of strategic, longer-term initiatives that are treated outside the Current PBR Plans' framework. FEI, for example, has been a North American leader in RNG and NGT related programs and has introduced a number of unique innovations to these developing fields. For instance, FEI is the first company in the world to offer an on-board truck-to-ship LNG bunkering system. As stated in Section B1, FortisBC believes it is in the public interest for it to continue to support climate objectives and adjust its business so that it can continue to serve its customers in a lower carbon future. Thus, it must focus on these initiatives, innovate, and advance emerging businesses for the benefit of customers.

FortisBC therefore proposes a suite of targeted incentives focused on areas where success will benefit customers by advancing the adoption of cleaner, lower emissions energy solutions and contribute to the realization of energy and emissions goals, increase customer engagement and manage rate increases through growth in system throughput.

FortisBC's proposed incentives are based on the Companies' level of success in achieving the scorecard targets included under each target section below. The financial incentive for successful achievement of a target is an amount equivalent to additional basis points added to the Companies' allowed ROE. For simplicity, this amount is to be calculated outside of the proposed Earnings Sharing Mechanism, as follows:

Targeted Incentive = Total Basis Points Achieved x Equity Portion of Approved Rate Base

An exception to this is the Power Supply Incentive, which has its own basis for calculation, and which is described in more detail below.

Targeted incentives are proposed as reward-only incentives. This design feature encourages FortisBC to expend effort towards achieving the targets within its O&M and capital funding constraints. Otherwise, a penalty for failing to achieve a targeted incentive could amount to a double penalty where the utility expends resources in pursuit of the incentive, but does not achieve it. As stated by the Western Interstate Energy Board, organizing targeted incentives as reward-only "encourages utilities to be more innovative, and may result in more collaborative and less adversarial processes".[187]

Another design feature of the targeted incentives is the addition of an MRP Target. The MRP Target provides an opportunity to evaluate overall performance and recognize the achievement of objectives on an overall basis. In other words, if the targets were missed in certain years, but the targets were achieved in aggregate, the Companies would earn the full incentive.

For example, if FEI experienced slow upfront growth of renewable gas, but introduced a large new renewable gas supply towards the end of the Proposed MRP, FEI may have missed annual targets at the beginning of the Proposed MRP period even though the overall supply target was achieved in the end. To recognize this issue and to ensure sustained progress towards achieving the target, achievement of the MRP Total for each incentive will trigger the

[187] Appendix C8, Utility Performance Incentive Mechanisms, A Handbook for Regulators, March 9, 2015, page 42.

'successful' completion overall and any annual targets missed will be added to the final total incentive.

Table C8-1 below summarizes FortisBC's proposed targeted incentives.

Table C8-1: Targeted Incentives for the Proposed MRP

Targeted Incentives			
Item	**Applicable to**	**Opportunity**	**Proposed Incentive (equivalent basis points)**
Growth in Renewable Gas	FEI	Incentive to exceed forecast renewable gas volumes	10 BPS
Growth in NGT	FEI	Incentive to exceed load growth forecast for transportation customers	10 BPS
GHG Emissions Reduction (Customer)	FEI	Incentive to exceed forecast natural gas conversion activity	5 BPS
GHG Emissions Reduction (Internal)	FEI	Incentive to reduce internal GHG emissions below targeted levels	5 BPS
Customer Engagement	FEI / FBC	Incentive to increase the adoption of digital service channels	5 BPS each
Growth in Electric Vehicle Transportation	FBC	Incentive to support the deployment of EV Charging infrastructure (subject to EV Inquiry)	5 BPS
Power Supply Incentive	FBC	Incentive to optimize power purchases	PSI calculated separately

Each of the areas with targeted incentives are described below.

8.3.1 Growth in Renewable Gas (FEI)

Renewable gas (RG)[188] is an increasingly important carbon neutral energy product that is a critically important tool in ensuring the role of gas infrastructure in a lower-carbon energy future. RG can be obtained from a wide variety of sources: landfills, curbside organics, wastewater treatment plants, and agriculture, food manufacturing and wood wastes. Renewable hydrogen, either from waste streams of hydrogen or from electrolysis using renewable electricity is also considered by FEI to be RG. RG includes RNG, the supply of which FEI has been successful in

188 "Renewable gas" describes a broader range of renewable gas solutions from traditional renewable natural gas generated from organic waste sources to other sources such as hydrogen gas.

growing since the inception of the RNG program in 2010. FEI's projected RNG production volume for 2018 was 342,300 GJs.[189]

As an indication of RG's importance, the provincial government in its CleanBC Plan highlighted the importance of this area and established the goal of a minimum requirement for 15 percent of renewable content in natural gas by 2030. As interest in RG continues to grow over the next number of years, FEI will face increased competition for RG supply in Canada and in the Pacific Northwest. FEI will need to sharpen its focus on fully developing innovative RG technology, securing RG supply, and increasing the amount of feedstock available to manufacture RG.

The RG market is experiencing strong customer demand and greater customer adoption contributes significantly to a lower emissions future. Providing a clean, low emission energy solution for customers also supports provincial and federal climate and environmental policy goals. Customers benefit directly from an increased supply of RG, which can be used to address their emissions objectives in lieu of other higher-cost alternatives. Moreover, it is expected that RG produced in advance of the implementation of the federal Clean Fuel Standard will offset against mandatory emission reductions and potentially avoid higher cost compliance pathways.

Including RG as part of the suite of targeted incentives will encourage FEI to focus on developing and expanding RG supply[190]. The target for total RG supply is shown in the table below.

Table C8-2: Annual Renewable Gas Volume Target (PJs)

	2020	2021	2022	2023	2024	MRP Target
RG Target	1.0	1.5	2.0	4.0	6.0	14.5

Achievement of these annual targets will justify a "successful" rating for this component of the scorecard. Achievement of the MRP Target will add any missed annual targets to the 2024 incentive calculation.

8.3.2 Growth in Natural Gas for Transportation (FEI)

Natural gas for transportation, including CNG and LNG, is a market that provides an environmentally beneficial and cost-competitive energy solution to customers. This market segment is more fully described in Section B1.3.4.1 of the Application. Transportation emissions account for approximately 39 percent of B.C.'s total GHG emissions, and using CNG or LNG can reduce GHG emissions by 15 to 25 percent over the use of diesel in transportation.

FEI has had success in growing this market. Annual NGT load has grown to approximately 2.0 PJs in 2018. This represents growth of about 39 percent since 2012.

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189 FEI Annual Review for 2019 Delivery Rates. Exhibit B-2, Page 83. The projected RNG production volume for 2018 was 342,300 GJs.

190 RG Supply is the volume of RG contracted for, produced or purchased onto the system.

The transportation sector is an area where growth in demand for natural gas can contribute significantly to a lower emissions future. NGT customers benefit directly from reduced emissions, operating costs, and carbon taxes and all ratepayers benefit from additional carbon credits sales for LNG used for transportation. Over the period between 2015 and 2018, sales of carbon credits generated $9.75 million in benefit for all ratepayers. Furthermore, the additional load on the gas distribution system helps mitigate rate pressure for all customers and preserves the economic viability of the natural gas system.

Including NGT as part of the suite of targeted incentives will encourage FEI to focus on developing and expanding this market. The target for total annual NGT consumption is defined in the table below.

Table C8-3: Annual Natural Gas for Transportation Consumption Targets (PJ's)

	2020	2021	2022	2023	2024	MRP Target
NGT Target	3.0	4.0	5.0	6.0	7.0	25.0

Achievement of the total annual targets, will justify a "successful" rating for this component of the scorecard. Achievement of the MRP Target will add any missed annual targets to the 2024 incentive calculation.

8.3.3 GHG Emissions Reductions - Customer (FEI)

Natural gas is a clean fuel that reduces carbon emissions and improves air quality in comparison to energy sources like propane and oil. In comparison to heating oil, natural gas can lower emissions by approximately 27 percent.[191] Continued success in converting customers to natural gas is not only important from an emissions perspective, but also from a load growth perspective. The additional load on the gas distribution system helps mitigate rate pressure for all customers and preserves the economic viability of the natural gas system. Customers also benefit directly from reduced costs and lower carbon taxes in comparison to higher carbon energy forms like heating oil or propane.

Historically, FEI has been successful in converting approximately 2,300 customers per year from other energy sources to natural gas. Table C8-4 below shows the history of natural gas conversions since 2014. High levels of housing construction in recent years have contributed to higher customer attachments, and higher conversions.

Table C8-4: Natural Gas Conversions

Year	Gross Customer Attachments	Conversions
2014	13,583	1,799
2015	16,213	2,091

191 2014 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. Page 12. 2014. Ministry of Environment. Province of British Columbia. www.toolkit.bc.ca.

Year	Gross Customer Attachments	Conversions
2016	17,255	1,647
2017	20,804	3,033
2018	22,547	4,488
Average 5 Years	18,080	2,612

The target for the annual number of natural gas conversions is 2,700 per year which reflects an increase over the five-year average. The five-year average includes record levels of gross customer additions and conversion activity, which is expected to ease in 2019 and through the Proposed MRP period making the achievement of 2,700 conversions increasingly difficult.

Table C8-5: Natural Gas Conversion Target

	2020	2021	2022	2023	2024	MRP Target
Conversion Target	2,700	2,700	2,700	2,700	2,700	13,500

Achievement of the annual target will justify a "successful" rating for this component of the scorecard. Achievement of the MRP Target will add any missed annual targets to the 2024 incentive calculation.

8.3.4 GHG Emissions Reductions - Internal (FEI)

With its large network of distribution and transmission pipeline used for transporting natural gas throughout the province to customers, managing GHG emissions is important to FEI. Since 2009, FEI has been successful in reducing overall GHG emissions by 15 percent.[192]

FEI has successfully undertaken a number of initiatives in the past to manage and reduce the GHG emissions from its system. The activities include:

- Electrification of LNG operations;
- Leak detection and repair at compressor stations;
- Developing 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;
- Conducting pipe surveys; and
- Inline inspection of transmission pipeline.

192 FEI Annual Review for 2019 Delivery Rates, Exhibit B-4, FEI Response to BCSEA IR 1.7.1.

Including this area as part of the suite of targeted incentives will encourage FEI to focus on reducing GHG emissions further and may lead to lower carbon tax costs and reduced commodity losses for FEI's own use gas.

The proposed target is based on GHG emissions reduction intensity as shown in Table C8-6 below for 2013 to 2017.

Table C8-6: GHG Emissions Intensity (2013 to 2017)[193]

Year	GHG Emissions from Operations (tCO_2e*)	Actual Energy Demand (PJ)[194]	Emissions Intensity (tCO_2e/PJ)
2013	141,947	200	711
2014	140,507	195	721
2015	120,997	186	651
2016	126,613	197	643
2017	142,534	221	645

** tonnes of CO_2e*

The table above shows a five-year average emissions intensity of 674 tCOe/PJ experienced between 2013 to 2017. FEI proposes to reduce GHG emissions intensity by 10 tCO_2e/PJ per year over the Proposed MRP term starting from the 2017-2019 average.

Table C8-7: Annual Emissions Intensity Reduction Target (tCO_2e/PJ)

	2020	2021	2022	2023	2024	MRP Target
Emissions Intensity Reduction Target[195]	10	20	30	40	50	>30 avg.

Achieving an emissions intensity below the annual targets would justify a "successful" rating for this component of the scorecard. Achievement of the MRP Target will add any missed annual targets to the 2024 incentive calculation.

8.3.5 Customer Engagement (FEI / FBC)

As referenced in Section B1 and C2, customer expectations are changing, including an increased expectation for communication channels that allow customers to engage on their own terms. To meet these expectations, FortisBC has expanded its communication channels to include telephone, automated phone options, email, mobile app and on-line account services to provide increased choices to customers. FortisBC's digital channels[196] provide customers with

[193] 2016 and 2017 includes LNG operations, which was not reportable based on definitions from the BC Ministry of Environment.
[194] Figures represent actual energy demand as opposed to weather normalized demand.
[195] Emissions Intensity Reduction Target is calculated as the 2017-2019 average less the applicable cumulative annual reduction.
[196] Current digital channels include email, mobile app and on-line account services.

convenient access to services and information and, while not all interactions are best suited for digital channels[197], increasing the adoption of these channels benefits customers by providing convenient, low effort interactions.

FortisBC measures the use of its digital channel offerings by recording the proportion of customer interactions that occur digitally versus through traditional channels. The table below illustrates the historic adoption rates of digital channel offerings.

Table C8-8: Historic Proportion of Digital Customer Interactions

	2014	2015	2016	2017	2018	2016-2018 Average	Average Annual Growth
FEI	21%	23%	25%	28%	36%	29%	4%
FBC	24%	28%	18%	22%	26%	22%	1%

The use of digital channels can be influenced by certain external events. For example, a large outage on the electrical system has historically driven high call volumes. Similarly, a cold winter period has historically driven higher calls relating to high bill inquiries. In order to normalize some of this variability, the average annual growth in digital tool adoption was used for the period of 2014 to 2018 as the target for the annual increase in adoption. In setting initial targets, FortisBC considered the annual volatility and the three-year average digital channel use rates. In the table below, a 4 percent (average annual growth) target is added each year to the baseline 2018 level.

Table C8-9: Digital Channel Use Target

	2020	2021	2022	2023	2024	MRP Total
FEI	40%	44%	48%	52%	56%	>48% avg.
FBC	27%	28%	29%	30%	31%	>29% avg.

In order to continue to increase adoption, FortisBC must continue to drive customer adoption of existing channels while also providing new and enhanced digital channel options. Achievement of the annual target will justify a "successful" rating for this component of the scorecard. Achievement of the MRP Target will add any missed annual targets to the 2024 incentive calculation.

8.3.6 Growth in Electric Vehicle Transportation (FBC)

The transportation sector represents 39 percent of BC's total emissions making it the most important sector where FortisBC can help achieve signification carbon reductions. Light-duty

197 Complex billing inquiries are an example of interactions that are well suited for the telephone.

transportation accounts for more than one third of total transportation emissions and 14 percent of BC's total emissions.[198] As part of CleanBC, the provincial government has announced a Zero Emissions Vehicle (ZEV)[199] mandate as follows:

- By 2025 10% of new vehicle sales are ZEVs;
- By 2030 30% of new vehicle sales are ZEVs; and
- By 2040 100% of new vehicle sales are ZEVs.

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.

On December 22, 2017, FBC applied for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging (DCFC) Service. On January 12, 2018, FBC received approval of rates on an interim basis and the proceeding was adjourned until further notice as the BCUC established an inquiry to review the regulation of electric vehicle charging service in British Columbia (EV Charging Inquiry).

Since FBC's role in supporting EV charging infrastructure in the province is among the issues that will be determined in the EV Charging Inquiry, FBC proposes to determine the appropriate targets following the conclusion of the Inquiry. Appropriate targets could range from direct investment by FBC to supporting third party investment in charging infrastructure. For this reason, the table below does not propose any targets at this time.

Table C8-10: EV Charging Infrastructure Deployment[200]

	2020	2021	2022	2023	2024	MRP Target
EV Charging Infrastructure	TBD	TBD	TBD	TBD	TBD	TBD

8.3.7 Power Supply Incentive (FBC)

FBC has opportunities to reduce power purchase expense (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

198 Appendix A5, Clean Growth Pathway to 2050. Page 12.
199 CleanBC. 2018. Province of British Columbia. https://cleanbc.gov.bc.ca.
200 Targets to be determined following the results of the Electric Vehicle Charging Inquiry.

opportunities arise. FBC must also ensure that these activities do not compromise security or reliability of supply for customers.

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
- they provide utilities with greater incentives to achieve desired outcomes and tie utilities' profits more to performance than to capital investments.[201]

FBC is, therefore, requesting approval of a Power Supply Incentive (PSI) to encourage the FBC to increase efficiency, reduce costs, and enhance performance in the area of power supply as detailed Appendix C7 of this Application as part of its suite of Target Incentives. The following provides a summary of the PSI mechanism that will be calculated separately from other targeted incentives.

The PSI mechanism is based on the following power supply optimization / mitigation activities:

- Displace BC Hydro Power Purchase Agreement (PPA) energy purchases with lower priced energy (PPA Energy Displacements);
- Displace capacity under the BC Hydro PPA with lower priced capacity (PPA Capacity Displacements);
- Release surplus Waneta Expansion capacity on a day-ahead basis (Surplus Sales); and
- Other optimization activities as brought forward and approved during future Annual Review processes.

FBC believes that returning to a sharing mechanism will encourage the FBC 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. Calculation of Eligible Mitigation Benefits (EMB) created by this activity, as compared to a passive strategy, are shared with customers on the following basis:

[201] Appendix C8, Utility Performance Incentive Mechanisms: A Handbook for Regulators.

- the first $7.5 million of any reduction in PPE as a result of optimization activity will be to the benefit of customers, and
- any remaining reduction is apportioned 90 percent to customers and 10 percent to the FBC.

FBC's power supply portfolio represents a significant component of FBC's revenue requirement, and requires a significant effort to optimize. The proposed PSI will encourage the FBC to increase efficiency, reduce costs, and enhance performance in power supply. The PSI has been designed to ensure the objectives below 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 FBC.
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 FBC. The PSI results in a reasonable benefit to FBC 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.

8.4 *ACCOUNTING TREATMENT OF INCENTIVES*

As in the Current PBR Plans, the incentives calculated under the Proposed MRP Earnings Sharing Mechanism described in Section C8.2 will be projected in the Annual Review materials each year and the customers' portion will be refunded or charged to customers in the subsequent year. FortisBC will make a final determination of the actual earnings amount for sharing after the year end, with any differences between the projected and actual amount included in the calculation of the earnings sharing for the following year.

The targeted incentives as set out in Section C.8.3 above (with the exception of the PSI) will be calculated on a final and full-year basis and therefore will be included in the Annual Review materials two years subsequent (for example, 2020 performance will be known in 2021 and will be evaluated for incentives in the Annual Review for 2022 rates).

FortisBC proposes the establishment of the MRP Incentive deferral accounts in Section C5 of the Application to record these incentives.

Finally, FortisBC proposes to record FBC's Power Supply variances net of the PSI, as described in Section C4.3.

8.5 CONCLUSION

The proposed combination of traditional and targeted incentives supports the achievement of a set of objectives for the benefit of customers and the continued health of the Utilities. Further, the proposed incentives represent an appropriate balance between traditional efficiency-focused metrics and incentives that address challenges and opportunities in the evolving operating environment.

9. PROPOSED RATE PLAN SUMMARY OF CHANGES AND RATE PROJECTION

9.1 INTRODUCTION

In the Proposed MRPs in this Application, FortisBC builds on past successful PBR plans and has incorporated features for the Companies to address the challenges in their operating environment, respond to intervener concerns and continue to provide safe and reliable service to their customers.

9.2 THE PLAN BUILDS ON PAST SUCCESSES

The Proposed MRPs represents an evolution of past successful plans, improving on various plan elements while also adapting to changes in FortisBC's operating environment. The key design themes of the Proposed MRPs are as follows:

- A 5-year rate plan that includes incentive for the utility to perform. The 5-year term promotes regulatory efficiency, sustained utility focus on managing the business, and flexibility to address emerging issues.
- Stable levels of O&M funding that are sufficient to address emerging pressures. This will provide certainty to support longer-term plans and initiatives, and encourage the Utilities to focus on the efficient allocation of resources within the business over time;
- A flexible approach that allows FortisBC to innovate and adapt to the changing environment. This is key to managing the transition to a lower carbon economy, while achieving a balance between affordability and lower emissions for current and future customers; and
- Incentive to invest in the future through load growth opportunities that help offset the costs associated with climate policy and meeting emissions reduction targets as well as meet growing demand for investment in system integrity and reliability.

The incentives in the Proposed MRPs include traditional incentives focused on encouraging the Utilities to be efficient in its allocation of resources, and targeted incentives that focus effort towards increasing customer engagement, increasing renewable fuel supply, lowering emissions, and encouraging growth in new businesses like RNG and clean transportation.

With increased focus on climate change and the environment, the need for innovation and the adoption of new technologies is of increasing importance to the Companies. In response, FortisBC has proposed an Innovation Fund to pursue the advancement of technologies.

9.3 THE PLAN ADDRESSES INTERVENER CONCERNS

FortisBC has sought input from interveners in its design of the Proposed MRPs and where appropriate, incorporated changes to address intervener feedback provided. In its efforts to develop MRPs that recognizes the interests and issues of concern of interveners, FortisBC engaged in a number of discussions with interveners in 2017 and 2018. The following is a summary of the discussions. For details of the discussions, refer to Section B2.5.

Non-Formula Approach for Determining Capital Funding

Interveners have commented that the existing formulaic capital funding mechanism is not working and that managing capital spending within the allowed funding was a challenge for FortisBC. In response, instead of continuing to use a formula approach to determine capital funding, FortisBC proposes to use a five-year cost of service forecast for the majority of its capital expenditures over the term of the Proposed MRPs. Interveners will have an opportunity to review the details of the proposed capital expenditures to ensure their reasonableness and appropriateness. This is discussed in Section C3 of the Application

An exception to the five-year capital expenditure forecast noted above is FEI's Growth capital. Due to the difficulties in forecasting customer attachment levels five years into the future, and to continue to focus on efficiencies in adding customers, FEI proposes to continue with a unit cost approach for FEI growth capital. FEI Growth capital is an area where FEI has experienced significantly higher capital expenditures than anticipated, partly due to an unprecedented number of customer attachments in recent years. The unit cost approach provides incentive for FEI to manage Growth capital expenditures efficiently. The unit cost approach for FEI growth capital is discussed in Section C3.3.1 of the Application.

Base O&M Funding is Index Based

Recognizing concerns expressed by interveners about the potential need for the utility to shift its focus from traditional "cost cutting", the Companies propose that Base O&M funding be "Index Based", with O&M funding during the term of the Proposed MRPs indexed to inflation only. This will provide the Companies with a stable level of O&M funding but de-emphasize the focus on achieving a significant accumulating productivity improvement factor each year. Further, as described in the Concentric Benchmarking Study contained in Appendix B2, FortisBC is operating relatively efficiently, lessening the need for a directed productivity focus. The Base O&M Indexing is discussed further in Section C2 of the Application.

Regulatory Framework focused on the Companies' Growth and Performance in a Challenging Operating Environment

Interveners have questioned the benefits of the focus of the Current PBR Plans on cost cutting and achieving productivity savings, suggesting that the benefits of the Current PBR Plan may also have been achieved under a traditional cost of service approach. While FortisBC disagrees with the perspective, it has attempted to address the concern by incorporating in its Proposed MRPs:

- Targeted performance incentives to encourage utility performance in specific areas, including increasing the use of the system in both traditional areas (i.e., natural gas distribution) and non-traditional areas (i.e., RNG, LNG, NGT). The targeted performance incentives are discussed further in Section C8 of the Application.
- Funding to support research and development of innovative technologies to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for our customers. During the intervener engagement sessions in October 2018, interveners expressed general interest and support in the Utilities pursuing innovative technologies. The innovation technology funding is discussed further in Section C6 of the Application.

<u>Reliability SQI for FEI Wholesale/Municipal Customers</u>

At the suggestion of the BCMEU representing wholesale/municipal customers, FBC proposes to add an SQI to its suite of SQIs to measure reliability for FBC's wholesale/municipal customers. The new wholesale/municipal reliability SQI is discussed further in Section C7 of the Application.

<u>ROE Sharing Mechanism</u>

Some interveners have expressed a desire for simplicity and ease of understanding in FortisBC's next ratemaking application. Instead of separate earnings impact calculations for O&M and capital expenditures as currently used, FortisBC proposes to adopt a broad earnings sharing mechanism based on a 50/50 basis sharing between customers and the Companies for earnings above and below the allowed ROE. The Earnings Sharing mechanism is discussed further in Section C8 of this Application.

9.4 *RATE IMPACTS ARE REASONABLE*

FortisBC is not requesting approval of 2020 rates at this time. FortisBC will file for interim 2020 rates before the end of 2019. Included in the 2020 rates filings, the Companies will propose amortization of the revenue surplus from prior years. FEI and FBC will file for permanent 2020 rates after the BCUC's decision in this Application. However, to provide an understanding of the rate implications of the various proposals included in this Application, FEI and FBC have calculated indicative rates for 2020 which are provided below.

Overall, the indicative rate increases for 2020 are not out of line with historical rate increases, and after consideration of potential rate mitigation through the existing revenue surpluses, would be in line with inflation. These rate levels incorporate both the impacts of a number of studies which are summarized in Section D and some significant Major Projects that are coming into service in 2020.

The tables below show the indicative 2020 delivery rate increases for FEI (Table C9-1) and indicative 2020 rate increases for FBC (Table C9-2). The tables group the rate impacts into three categories:

1. Adjustments to revenue requirements necessary to reset rate base at the termination of the Current PBR Plans and the resetting of Base O&M for the Proposed MRPs. The rate base impact is due to adding to rate base the capital expenditures excluded during the PBR term (expenditures within the dead band) and equals the equity component of the undepreciated cumulative plant within the dead band[202]. Adjustments to O&M are as described in Sections C2.4.2.2 and C2.5.2.2 and are net of capitalized overheads.
2. Adjustments from various accounting and allocation studies which are summarized in Section D of the Application. These include the depreciation studies, lead/lag studies, shared services study and corporate services studies.
3. High-level projections of other revenue requirement changes for 2020.

These projected rate impacts for 2020 should be considered indicative only and will be updated in FortisBC's future requests for interim rates to be filed later in 2019. The Companies may also propose the utilization of part or all of their respective revenue surplus deferral accounts, which is not included in these indicative rates, to mitigate the rate increases. The existing revenue surplus accounts are available to offset the delivery rate increase by up to approximately 4.8 percent for FEI and the rate increase by up to approximately 1.3 percent for FBC.

Included in Tables C9-1 and C9-2, the Projected Revenue Requirements - Other line item is the proposed Canada Revenue Agency tax change that allows 150 percent of the normal Capital Cost Allowance (CCA) rate to be claimed on the Undepreciated Capital Cost (UCC) pool additions in the year that they are added. The Companies have embedded this proposed tax change into the indicative rates but note that the proposed change is not yet enacted, and the Companies are still analysing the impacts, such that the rate proposals for implementing this change may vary from what has been set out below.

[202] The equity component is the only cost component of plant within the dead band that has not been accounted for in the Flow-through deferral account.

Table C9-1: FEI Indicative 2020 Delivery Rate Change

Particulars	Revenue Requirement $millions
PBR/MRP Plans	
Resetting Rate Base	2.0
Resetting Net O&M	(0.7)
Subtotal	1.3
Studies	
Depreciation Study	3.5
Shared Services Study	(0.3)
Corporate Services Study	(0.1)
Cash Working Capital - Lead Lag Study	(0.2)
Subtotal	2.9
Projected Revenue Requirements	
Customer Growth and Volume - Margin	3.4
LMIPSU - Coquitlam and Burnaby portions	32.2
Rate Base Growth	7.2
Net O&M	4.7
Deferral Accounts	(0.6)
Other	(7.9)
Subtotal	39.1
Total	43.3
Margin @ Existing Rates	810.4
Approximate Delivery Rate Change	**5.3%**

As noted above, the 5.3 percent delivery rate change in Table C9-1 is indicative only. The overall rates in 2020 includes the delivery rate, as well as commodity and storage and transport rates. All else equal, the overall rate (the annual bill) increase that results from the delivery rate increase is 2.6 percent or $1.75 per month for the average residential customer. Further, taking into account the proposed Innovation Fund rider of $0.40 monthly per customer, the overall bill impact to the average residential customer is approximately $2.15 per month.

1 **Table C9-2: FBC Indicative 2020 Rate Change**

Particulars	Revenue Requirement $millions
PBR/MRP Plans	
Resetting Rate Base	0.6
Resetting Net O&M	0.9
Subtotal	1.5
Studies	
Depreciation Study	2.2
Shared Services Study	0.3
Corporate Services Study	0.4
Cash Working Capital - Lead Lag Study	0.1
Subtotal	3.0
Projected Revenue Requirements	
Net Margin (Revenue less Power Supply)	1.9
Corra Linn Spillway Gates/UBO Refurbishment	1.6
Rate Base Growth	3.4
Net O&M	2.7
Deferral Accounts	4.1
Other	(3.3)
Subtotal	10.4
Total	15.0
Revenue @ Existing Rates	373.3
Approx. Rate Change	**4.0%**

2

3 As noted above, the rate change in Table C9-2 is indicative only. The 4.0 percent rate increase
4 is equal to approximately $4.75 per month for the average residential customer. Further, taking
5 into account the proposed Innovation Fund rider of $0.30 monthly per customer, the overall bill
6 impact to the average residential customer is approximately $5.05 per month.

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Section D:

POLICIES AND SUPPORTING STUDIES

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D: POLICIES AND SUPPORTING STUDIES

1. INTRODUCTION

FortisBC will continue to report on any accounting policy changes in its Annual Reviews during the term of the Proposed MRPs, and bring forward any changes for approval as required. In this Application, FortisBC is not proposing any accounting policy changes.

In the sections that follow, FortisBC provides updated versions of the various studies that will support the calculation of revenue requirements for the term of the Proposed MRPs. These include:

Section D2 – Depreciation Studies

Section D3 – Lead/Lag Studies

Section D4 – Shared Services Study

Section D5 – Corporate Services Studies

Section D6 – Capitalized Overhead Studies

2. DEPRECIATION STUDY

2.1 INTRODUCTION

In this Application, FortisBC is proposing updates to the depreciation rates and net salvage rates for FEI and FBC based on the results of the depreciation studies for FEI and FBC included in Appendices D2-1 and D2-2, respectively (2017 Depreciation Studies). The filing of the 2017 Depreciation Studies in this Application complies with the BCUC's recommendation on page 14 of the Decision attached to Order G-193-15 that depreciation studies be filed separate from the Annual Review process.

FEI and FBC retained Concentric, formerly known as Gannett Fleming, to perform a review of depreciation rates for both FEI and FBC. The results of this review are included in the 2017 Depreciation Studies in Appendices D2-1 and D2-2 which have been prepared based on FEI's and FBC's plant-in-service balances as of December 31, 2017. The last depreciation studies were prepared using the plant-in-service balances for FEI and FBC as of December 31, 2014 (2014 Depreciation Studies).

Consistent with the 2014 Depreciation Studies, Concentric has estimated the depreciation rates using the straight-line method and the Average Life Group (ALG) procedure applied on a remaining life basis for each depreciable group of assets. The life and net salvage rates were developed using various statistical methods such as Iowa type survivor curves and "goodness of fit" criterion, a review of actual retirement activity, operational interviews with FEI and FBC staff and informed judgement based on their experience in the gas and electricity industries. The process followed by Concentric involves the determination of an estimated average service life for each asset class and whether certain assets have depreciation surpluses or deficits, both of which drive the recommended depreciation rates. Straight-line depreciation is developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics, and accounting for the accumulated depreciation already booked in that class.

The result of the 2017 Depreciation Studies is recommended updates for both depreciation rates and net salvage rates for FEI and FBC. The 2017 Depreciation Studies are summarized below.

2.2 2017 DEPRECIATION STUDY FOR FEI

FEI implemented the depreciation and net salvage rates from the 2014 Depreciation Study effective January 1, 2017 pursuant to Order G-119-16. FEI's 2017 Depreciation Study included in Appendix D2-1 was prepared based on gas plant-in-service as of December 31, 2017.

The overall results of the 2017 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, are shown in Tables D2-1 and D2-2 below. Implementation of the rates from the 2017 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $3.5 million per year, a 0.08 percent overall increase to the composite depreciation rate compared to the current approved rates. The resulting increase to the delivery rate is less than one percent.

Table D2-1: Impact of Implementing Depreciation Study Recommendations for FEI ($ millions)

	Existing	Recommended	Change
Depreciation	$ 176.7	$ 169.0	$ (7.7)
Net Salvage	$ 33.9	$ 44.8	$ 10.9
CIAC	$ (8.5)	$ (8.2)	$ 0.3
Total	**$ 202.1**	**$ 205.7**	**$ 3.5**

Table D2-2: Depreciation Study Average Rate Recommendations for FEI (percent)

	Existing	Recommended	Change
Depreciation	3.06%	2.93%	-0.13%
Net Salvage	0.65%	0.86%	0.21%
Total	**3.71%**	**3.79%**	**0.08%**

Further discussion of Concentric's recommended changes to depreciation, net salvage and amortization of CIAC follows below.

2.2.1 Depreciation Rates

The 2017 Depreciation Study was developed using the ALG depreciation methodology, consistent with the 2014 Depreciation study. The 2017 Depreciation study recommends an average composite depreciation rate of 2.93 percent for FEI, which is a decrease from the 3.06 percent derived from the 2014 Depreciation Study.

While there are certain specific asset classes that are expected to have slightly longer service lives based on actual retirement history, the overall decrease in the average composite depreciation rate is not indicative of overall longer expected service lives for FEI's assets. Instead, the adjustment downward in the average composite depreciation rate is primarily attributable to depreciation surpluses for certain asset classes that put downward pressure on the depreciation rates. The existence of depreciation surpluses and deficits occur in the normal course of asset retirements and one of the objectives for undertaking a depreciation study on a cyclical basis is to recommend depreciation rates that will prospectively unwind such variances.

The decrease in the average composite depreciation rate is also partially attributable to the one-year delay pursuant to Order G-119-16 in applying the decrease in the average composite depreciation rate from the prior rate of 3.19 percent to the 3.06 percent recommended in the 2014 Depreciation Study. The delay in implementing the recommended depreciation rates originally intended to be effective January 1, 2016 has required a catch-up which is reflected in the 2.93 percent average composite depreciation rate recommended in the 2017 Depreciation study.

These factors result in total FEI depreciation expense decreasing approximately $7.7 million due to the changes in the depreciation rates. This change excludes the effects on depreciation expense resulting from additions and retirements to property, plant and equipment (PP&E), as well as changes to the net salvage rates. The recommended depreciation rates are set out in Table D2-3 below. Rates noted with an asterisk are not included in the depreciation study since they are calculated separately by reference to other criteria (for example, lease structures and vehicles are depreciated based on specific lease terms).

Table D2-3: Impact of Implementing Recommended Depreciation Rates for FEI[203]

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
1	175-00	Unamortized Conversion Expense - Squamish*	10.00%	10.00%	77,732	77,732	-
2	175-10	Unamortized Conversion Expense *	1.00%	1.00%	1,087	1,087	-
3	178-00	Organization expense	1.00%	1.00%	7,281	7,281	-
4	401-01	Franchises and Consents	5.39%	1.08%	10,673	2,139	(8,534)
5	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	14,215,172	14,215,172	-
6	402-02	Computer S/W-Applic 5 Year	20.00%	20.00%	4,111,990	4,111,990	-
7	402-03	Intangible Plant	2.01%	2.50%	38,322	47,665	9,342
9	432-00	Mfg. Gas Structures	2.82%	2.50%	27,985	24,810	(3,176)
10	433-00	Mfg. Gas Equipment	4.66%	5.00%	24,062	25,817	1,756
11	434-00	Mfg. Gas Holders	2.45%	2.50%	72,395	73,872	1,477
12	436-00	Mfg. Gas Compressor Equipment	3.68%	4.00%	13,490	14,663	1,173
13	437-00	Mfg. Gas Meas/Reg Equipment	2.34%	5.00%	28,803	61,544	32,741
14	442-00	LNG Gas Structures	3.03%	2.20%	157,845	114,607	(43,238)
15	443-00	LNG Gas Equipment	1.88%	1.23%	314,219	205,579	(108,639)
16	449-00	LNG Gas Other Equipment	3.83%	2.77%	985,838	712,995	(272,843)
17	442-01	LNG Gas - Structures Mt. Hayes	3.88%	3.85%	738,702	732,991	(5,712)
18	443-05	LNG Gas Equipment Mt. Hayes	1.65%	1.65%	1,000,886	1,000,886	-

[203] In addition to the impact on FEI, Fort Nelson's composite depreciation rate decreases from 2.84% to 2.67% from these depreciation rate changes, resulting in a decrease of approximately $26,200 in annual depreciation expense. FEI will address this change in the next revenue requirement application for Fort Nelson.

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
19	448-10	LNG Gas - Piping Mt. Hayes	2.46%	2.45%	305,853	304,609	(1,243)
20	448-20	LNG Gas - Pre-Treatment Mt. Hayes	3.88%	3.84%	1,134,587	1,122,890	(11,697)
21	448-30	LNG Gas - Liquefaction Equipment Mt. Hayes	2.46%	2.45%	710,525	707,636	(2,888)
22	448-40	LNG Gas - Send Out Equipment Mt. Hayes	2.44%	2.41%	574,744	567,677	(7,067)
23	448-50	LNG Gas - Sub-Station and Electrical Mt. Hayes	2.44%	2.41%	531,699	525,162	(6,537)
24	448-60	LNG Gas - Control Room Mt. Hayes	6.30%	6.09%	400,308	386,965	(13,344)
25	448-65	LNG Gas - Mt. Hayes Inspection*	20.00%	20.00%	333,112	333,112	-
26	449-01	LNG Gas - Other Equipment Mt. Hayes	2.86%	3.08%	160,172	172,493	12,321
27	465-30	LNG - Mains Mt. Hayes	1.51%	1.54%	95,247	97,139	1,892
28	467-00	LNG - Measuring and Regulating Equipment Mt. Hayes	2.58%	2.34%	137,797	124,979	(12,818)
29	462-00	TP Compressor Structures	3.51%	3.32%	1,107,827	1,047,859	(59,968)
30	463-00	TP Meas/Reg Structures	2.29%	2.13%	345,019	320,913	(24,106)
31	464-00	TP Other Structures	3.66%	3.62%	247,715	245,008	(2,707)
32	465-00	TP Transmission Pipeline	1.47%	1.46%	18,002,806	17,880,337	(122,468)
33	465-20	TP Mains - Inspection *	15.20%	15.20%	5,527,272	5,527,272	-
34	465-10	TP Mains - Byron Creek *	5.03%	5.03%	68,966	68,966	-
35	466-00	TP Compressor Equipment	2.89%	2.42%	5,505,743	4,610,345	(895,398)
36	466-10	TP Compressor Equipment - Overhauls *	10.19%	10.19%	1,008,737	1,008,737	-
37	467-10	TP Meas/Reg Equipment	2.41%	2.12%	1,478,438	1,300,535	(177,903)
38	467-20	TP Telemetry Equipment	9.75%	8.97%	1,678,482	1,544,203	(134,279)
39	467-30	TP Meas/Reg Equipment - Byron Creek *	2.41%	2.41%	7,023	7,023	-
40	468-00	TP Communications Equipment	0.56%	0.00%	21,085	-	(21,085)
41	465-11	IP Transmission Pipeline (Whistler Pipeline)	1.53%	1.54%	647,127	651,356	4,230

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
42	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	2.55%	2.26%	7,990	7,082	(909)
43	472-00	DS Structures	2.41%	2.15%	601,581	536,680	(64,901)
44	472-10	DS Structures - Byron Creek *	4.67%	4.67%	5,773	5,773	-
45	473-00	DS Services	2.45%	2.18%	28,375,580	25,248,475	(3,127,105)
46	474-00	DS Meters/Regulators Installations	5.99%	7.45%	11,253,730	13,996,709	2,742,979
47	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	6,004,141	6,004,141	-
48	475-00	DS Mains	1.54%	1.35%	21,941,331	19,234,283	(2,707,047)
50	477-20	DS Telemetering	2.82%	3.59%	414,291	527,413	113,122
51	477-10	DS Meas/Reg Additions	3.05%	2.51%	4,311,189	3,547,897	(763,292)
53	478-10	DS Meters	7.09%	6.06%	18,161,918	15,523,445	(2,638,473)
54	478-20	DS Instruments	2.99%	2.92%	400,715	391,333	(9,381)
55	472-20	Biogas - Structures and Improvements	2.72%	2.69%	17,813	17,617	(196)
56	475-10	Biogas - Mains on Municipal Land	1.55%	1.56%	24,810	24,970	160
57	475-20	Biogas - Mains on Private Land	1.55%	1.56%	855	861	6
58	418-10	Biogas - Purification Overhaul	5.00%	5.00%	1,021	1,021	-
59	418-20	Biogas - Purification Upgrader	4.89%	5.00%	478,969	489,744	10,774
60	477-40	Biogas - Reg and Meter Equipment	3.24%	3.22%	83,126	82,613	(513)
61	474-10	Biogas - Reg and Meter Installations	5.24%	5.32%	11,845	12,026	181
62	478-30	Biogas - Meters	5.02%	4.89%	1,771	1,725	(46)
63	483-25	RNG Comp S/W	20.00%	20.00%	27,692	27,692	-
64	476-10	NGV - Transport CNG Dispensing Equipment	5.00%	5.00%	644,875	644,875	-
65	476-20	NGV - Transport LNG Dispensing Equipment	5.00%	5.00%	584,159	584,159	-
66	476-30	NGV - Transport CNG Foundations	5.00%	5.00%	118,256	118,256	-
67	476-40	NGV - Transport LNG Foundations	5.00%	5.00%	65,568	65,568	-
68	476-50	NGV - Transport LNG Pumps	10.00%	10.00%	149,411	149,411	-
69	476-60	NGV - CNG Dehydrator	5.00%	5.00%	24,388	24,388	-
70	482-10	GP (Frame) Structures	6.04%	3.17%	1,279,904	671,738	(608,167)

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
71	482-20	GP (Masonry) Structures	1.95%	1.52%	2,236,675	1,743,459	(493,215)
72	482-30	GP (Leased) Structures *	9.49%	9.49%	551,691	551,691	-
73	483-10	GP Computer Hardware	20.00%	25.00%	7,350,483	9,188,104	1,837,621
74	483-20	GP Computer Systems Software	12.50%	12.50%	896,870	896,870	-
75	483-30	GP Office Equipment	6.67%	6.67%	224,858	224,858	-
76	483-40	GP Furniture	5.00%	5.00%	890,229	890,229	-
77	484-00	GP Vehicles	10.55%	11.07%	2,162,995	2,269,607	106,612
78	484-10	Vehicles-Leased*	9.44%	9.44%	1,510,646	1,510,646	-
79	485-10	GP Heavy Work Equipment	6.38%	5.14%	57,779	46,549	(11,230)
80	485-20	GP Heavy Mobile Equipment	9.85%	6.09%	530,374	327,917	(202,458)
81	486-00	GP Small Tools/Equipment	5.00%	5.00%	2,362,977	2,362,977	-
82	487-20	GP NGV Cylinders	6.67%	6.67%	823	823	-
83	488-10	GP Telephone Equipment	6.67%	6.67%	224,156	224,156	-
84	488-20	GP Radio Equipment	6.67%	6.67%	865,030	865,030	-
85		**Total Annual Depreciation**			**176,715,057**	**169,028,861**	**(7,686,196)**
87		**Annual Composite Rate**			**3.06%**	**2.93%**	

Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2018 gross asset values.

The asset categories with the more significant changes in their depreciation rate as compared to the 2014 Depreciation Study are Compressor Equipment (466-00), Services (473-00), Meters and Regulators Installations (474-00), Distribution Mains (475-00), Meters (478-10), and Computer Hardware (483-10). Each of these asset categories is discussed below. Refer to pages 3-3 to 3-15 of the 2017 Depreciation Study included in Appendix D2-1 for further details and discussion.

2.2.1.1 Compressor Equipment (466-00)

For Compressor Equipment (466-00), Concentric recommends a 37-year life, an increase from the 35-year service life recommended in the 2014 Depreciation Study.

Based on a review of retirements, additions and other plant transactions for the period 1965 to 2017, and comments from the operations and management group, the professional judgement of Concentric is that an average service life of 37 years is more reflective of the historical data.

The average age of retirements from 2014 through 2017 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.

The recommended longer service life and the true-up for the depreciation rate over the remaining life of the assets result in a decrease of approximately 0.47 percent in the depreciation rate for Compressor Equipment. The inclusion of a true-up in the development of the depreciation rate is necessary to recognize that over the life of a group of assets, differences may arise (i.e., due to change in expected life of assets) between the booked and the calculated (theoretical) accumulated depreciation reserve.

2.2.1.2 Services (473-00)

For Services (473-00), Concentric recommends a 47-year life, an increase from the 45-year service life recommended in the 2014 Depreciation Study.

A review of retirements, additions and other plant transactions for the period 1963 to 2017 suggests that an average service life of 47 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account.

The average age of retirement from 2014 through 2017 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.

Additionally, in determining the recommended 47-year life, Concentric reviewed a selection of peer Canadian natural gas distribution companies and the average service life estimates among these peers ranged from 40 through 62 years. For FEI, as this account contains predominantly ¾ inch steel and plastic service lines which are very rarely replaced, the life of its services is expected to be on the longer end of peer utilities.

Refer to pages 3-9 and 3-10 of Appendix D2-1 FEI Depreciation Study for further details.

The recommended longer service life and the true-up for the depreciation rate over the remaining life of the assets result in a decrease of 0.27 percent in the depreciation rate for Services.

2.2.1.3 Meters and Regulators Installations (474-00)

For Meters and Regulators Installations (474-00), Concentric recommends changing the annual depreciation accrual to be weighted in accordance with the two groups of assets in this account. 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 related to the installation of meters costs follows an amortization accounting method where these assets are expected to be completely retired in

2035. The remaining 13 percent of this account, relating to installation of station regulators, follows traditional regulatory retirement accounting practices and are expected to be in service until the end-of-life of the asset.

With the recommended weighted 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. 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. These recommended survivor curves were based on the indications from management and operations, and on the professional judgement of Concentric.

Refer to pages 3-10 and 3-11 of Appendix D2-1 FEI Depreciation Study for further details.

This change and the true-up of the depreciation rate over the remaining life of the assets result in an increase of 1.46 percent in the depreciation rate for this asset category.

2.2.1.4 Distribution Mains (475-00)

For Distribution Mains (475-00), Concentric recommends a 65-year life, an increase from the 64-year service life recommended in the previous study. This account contains steel and plastic distribution mains. The Distribution Mains account contains both steel and plastic distribution mains; however, FEI did not begin to install plastic mains until 1981 suggesting there is no early plastic replacement program required. Thus, the life of mains should be on the longer end of the range experienced by peer utilities where service life estimates ranged from an average of 61 through 68 years.

A recent review of retirements, additions and other plant transactions for the period 1924 to 2017, along with comments from the operations and management group, and based on the professional judgement of Concentric suggested that an average service life of 65 years is more reflective of the historical data.

The average age of retirement from 2014 through 2017 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.

Refer to pages 3-11 and 3-12 of Appendix D2-1 FEI Depreciation Study for further details.

The recommended longer service life and the true-up for the depreciation rate over the remaining life of the assets result in a decrease of 0.19 percent in the depreciation rate for Distribution Mains.

2.2.1.5 Meters (478-10)

For Meters (478-10), Concentric recommends an 18-year life that is the same as recommended in the previous study. Review of retirement transactions and discussions with the operations and management group suggests that an average service life of 18 years is still reflective of the historical retirement activity and falls within the typical range of lives used for this account. Concentric reviewed a selection of peer Canadian natural gas distribution companies and the average service life estimates among these peers ranged from 15 through 30 years.

As a result of an accumulated depreciation deficiency that existed in this asset class as of the date of the previous study, a higher rate was incorporated at that time to make up for the historical under depreciation. While the average service life for Meters remains at 18 years, the depreciation rate is recommended to decrease from 7.09 percent to approximately 6.06 percent, primarily due to no longer requiring a true up of the accumulated depreciation deficiency pursuant to the 2014 Depreciation Study.

Refer to pages 3-11 and 3-12 of Appendix D2-1 FEI Depreciation Study for further details.

FEI highlights that it 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 FEI proceed with the initiative.

2.2.1.6 Computer Hardware (483-10)

For Computer Hardware (483-10), Concentric recommends a four-year life, a decrease from the five-year service life recommended in the previous study. This change is primarily due to discussions with FEI Information systems management indicating that on average the total life expectancy of computer hardware is four years or less. FEI is deploying a majority of the hardware as mobile devices, such as laptops and smartphones, and mobile devices tend to last less than four years due to the nature of the use. Desktops can last up to five years; however, other devices, such as printers and monitors, tend to last less than five years. In addition, obsolescence is also a factor, particularly with recent changes required to ensure cyber security. The shortening of the computer hardware asset life by one year increases the depreciation rate from 20 percent to 25 percent for this asset category.

2.2.2 Net Salvage

As approved by the BCUC, FEI provides for net salvage (removal costs less salvage proceeds) on its existing assets as a cost of providing service, recovered from customers over the useful life of the asset.

> **The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications.**[204]

The current 2017 Depreciation Study includes updated estimates of net salvage rates which FEI has included in amortization expense. As directed by the BCUC in the 2012-2013 RRA Decision, FEI records its negative salvage provision in its deferral schedules rather than within the plant continuity schedules:

> **Therefore, the Commission Panel directs the FEU to establish a rate base credit account to tabulate the total net negative salvage provisions less actual salvage costs. The Panel does not approve the presentation of the net negative salvage provision as a component of plant-in-service within the Utilities' assets.**[205]

The result is that the net salvage expense is included as a component of deferred charge amortization expense.

The updated net salvage rates based on gas plant-in-service as of December 31, 2017 is included in Appendix D2-1, Section 5 of the 2017 Depreciation study.

The asset classes where net salvage is included are shown in Table D2-4 below, comparing the recommended and existing net salvage rates and the impact on net salvage expense. As recommended by the 2017 Depreciation Study, the average composite net salvage rate increases from 0.65 percent using the current approved rates to 0.86 percent using the recommended rates. The recommended net salvage rate increase is supported by the increases in FEI's actual cost of asset removal activities. This change results in an increase to net salvage expense of approximately $10.9 million.

[204] 2012-2013 RRA Decision Directive 34.
[205] 2012-2013 RRA Decision Directive 33.

1 **Table D2-4: Impact of Implementing Recommended Net Salvage Rates for FEI[206]**

Line #	Class	Description	Net Salvage 2014	Net Salvage 2017	2014 Depreciation study Net Salvage Rate	2017 Depreciation study Net Salvage Rate	Net Salvage Based on 2014 Rate	Net Salvage Based on 2017 Rate	Increase + / Decrease -
1	437-00	Mfg. Gas Meas/Reg Equipment	n/a	n/a	0.03%	0.00%	369	-	(369)
2	442-00	LNG Gas Structures	-10%	-10%	0.36%	0.68%	18,754	35,424	16,670
3	443-00	LNG Gas Equipment	-20%	-20%	0.45%	1.12%	75,212	187,194	111,982
4	449-00	LNG Gas Other Equipment	-10%	-10%	0.39%	0.82%	100,386	211,067	110,682
5	442-01	LNG Gas - Structures Mt. Hayes	-10%	-10%	0.45%	0.49%	85,674	93,290	7,615
6	443-05	LNG Gas Equipment Mt. Hayes	-20%	-20%	0.35%	0.36%	212,309	218,375	6,066
7	448-10	LNG Gas - Piping Mt. Hayes	-10%	-10%	0.27%	0.28%	33,569	34,812	1,243
8	448-20	LNG Gas - Pre-Treatment Mt. Hayes	-10%	-10%	0.46%	0.50%	134,513	146,210	11,697
9	448-30	LNG Gas - Liquefaction Equipment Mt. Hayes	-20%	-20%	0.54%	0.57%	155,969	164,634	8,665
10	448-40	LNG Gas - Send Out Equipment Mt. Hayes	-10%	-10%	0.27%	0.28%	63,599	65,954	2,356
11	448-50	LNG Gas - Sub-Station and Electrical Mt. Hayes	-20%	-20%	0.54%	0.56%	117,671	122,029	4,358
12	449-01	LNG Gas - Other Equipment Mt. Hayes	-10%	-10%	0.28%	0.32%	15,681	17,921	2,240
13	465-30	LNG - Mains Mt. Hayes	-20%	-20%	0.32%	0.30%	20,185	18,923	(1,262)
14	467-00	LNG - Measuring and Reg Equip Mt. Hayes	-7%	-7%	0.21%	0.21%	11,216	11,216	-
15	462-00	TP Compressor Structures	-3%	-3%	-0.02%	0.11%	(6,312)	34,718	41,031
16	463-00	TP Meas/Reg Structures	-15%	-15%	0.57%	0.62%	85,878	93,411	7,533

206 In addition to the impact on FEI, Fort Nelson's composite negative salvage depreciation rate increases from 0.62% to 0.79% from these depreciation rate changes, resulting in an increase of approximately $25,200 in annual amortization expense. FEI will address this change in the next revenue requirement application for Fort Nelson.

Line #	Class	Description	Net Salvage 2014	Net Salvage 2017	2014 Depreciation study Net Salvage Rate	2017 Depreciation study Net Salvage Rate	Net Salvage Based on 2014 Rate	Net Salvage Based on 2017 Rate	Increase + / Decrease -
17	464-00	TP Other Structures	-5%	-5%	0.22%	0.29%	14,890	19,628	4,738
18	465-00	TP Transmission Pipeline	-20%	-20%	0.37%	0.42%	4,531,318	5,143,659	612,340
19	466-00	TP Compressor Equipment	-2%	-3%	-0.12%	0.07%	(228,612)	133,357	361,969
20	467-10	TP Meas/Reg Equipment	-7%	-5%	0.22%	0.16%	134,961	98,154	(36,808)
21	468-00	TP Communications Equipment	n/a	n/a	-0.38%	0.00%	(14,308)	-	14,308
22	465-11	IP Transmission Pipeline (Whistler Pipeline)	-20%	-20%	0.34%	0.34%	143,806	143,806	-
23	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	-7%	-7%	0.22%	0.35%	689	1,097	407
24	472-00	DS Structures	-10%	-15%	0.32%	0.52%	79,878	129,802	49,924
25	473-00	DS Services	-60%	-70%	1.61%	2.09%	18,646,810	24,206,107	5,559,297
26	474-00	DS Meters/Regulators Installations	-20%	-20%	1.77%	3.37%	3,325,393	6,331,397	3,006,005
28	475-00	DS Mains	-25%	-25%	0.43%	0.50%	6,126,475	7,123,809	997,333
30	477-20	DS Telemetering	-5%	-5%	0.42%	0.48%	61,703	70,518	8,815
31	477-10	DS Meas/Reg Additions	-10%	-12%	0.46%	0.45%	650,212	636,077	(14,135)
32	478-10	DS Meters	n/a	n/a	-0.26%	0.00%	(666,022)	-	666,022
33	472-20	Biogas - Structures and Improvements	-10%	-10%	0.29%	0.29%	1,899	1,899	-
34	475-10	Biogas - Mains on Municipal Land	-25%	-25%	0.39%	0.39%	6,243	6,243	-
35	475-20	Biogas - Mains on Private Land	-25%	-25%	0.39%	0.39%	215	215	-
36	418-20	Biogas - Purification Upgrader	-5%	-5%	0.26%	0.24%	25,467	23,508	(1,959)
37	474-10	Biogas - Reg and Meter Installations	-25%	-25%	1.35%	1.44%	3,052	3,255	203
38	478-30	Biogas - Meters	n/a	n/a	-0.21%	0.00%	(74)	-	74

Line #	Class	Description	Net Salvage 2014	Net Salvage 2017	2014 Depreciation study Net Salvage Rate	2017 Depreciation study Net Salvage Rate	Net Salvage Based on 2014 Rate	Net Salvage Based on 2017 Rate	Increase + / Decrease -
39	482-10	GP (Frame) Structures	0%	-4%	0.25%	0.37%	52,976	78,405	25,429
40	482-20	GP (Masonry) Structures	-10%	-4%	0.25%	0.08%	286,753	91,761	(194,992)
41	484-00	GP Vehicles	4%	15%	-1.00%	-3.70%	(205,023)	(758,586)	(553,563)
42	485-10	GP Heavy Work Equipment	5%	5%	-0.68%	-0.67%	(6,158)	(6,068)	91
43	485-20	GP Heavy Mobile Equipment	15%	15%	-2.89%	-1.80%	(155,612)	(96,921)	58,691
44		**Total Annual Net Salvage**					**33,941,602**	**44,836,300**	**10,894,697**
45									
46		**Annual Composite Rate**					**0.65%**	**0.86%**	

1 Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2018 gross asset values.

The asset categories that account for the majority of the change in net salvage expense are Services (473-00), Meters and Regulators Installations (474-00) and Distribution Mains (475-00). Refer to pages 3-3 to 3-15 of the Depreciation Study included in Appendix D2-1 for further details and discussion.

2.2.2.1 Services (473-00)

For Services (473-00), Concentric recommends a negative 70 percent rate to represent the net salvage expectations, an increase from the negative 60 percent recommended in the previous study. This account continues to witness a significant amount of net salvage activity consistent with prior years. A recent review of the retirements and discussions with FEI's management indicates that the historical results would be a reasonable basis for future expectations for the equipment in this account. The recommended increase by negative 10 leads to an increase of approximately 0.48 percent in the overall net salvage rate for this asset category.

2.2.2.2 Meters/Regulators Installations (474-00)

For Meters/Regulators Installations (474-00), Concentric recommends a negative 20 percent rate to represent the net salvage expectations, which is the same net salvage percent recommended in the 2014 Depreciation Study. This account has witnessed a significant amount of net salvage activity since 2002 with a higher level of negative net salvage in more recent years compared to the earlier years. Even though the net salvage percent remains at negative 20 percent, Concentric is recommending an increase in the net salvage provision rate of approximately 1.60 percent for this asset category to true up the accumulated net salvage provision deficiency.

2.2.2.3 Distribution Mains (475-00)

For Distribution Mains (475-00), Concentric recommends maintaining a negative 25 percent rate for net salvage consistent with the 2014 Depreciation Study. This account continues to witness significant amount of net salvage activity consistent with prior years. A recent review of the retirements and discussions with FEI's management indicates that the historical results would be a reasonable basis for future expectations for the equipment in this account. Even though it is recommended to keep the same net salvage percentage, the net salvage provision rate is increasing from 0.43 percent to 0.50 percent, an increase of 0.07 percent, to address the accumulated net salvage provision deficiency.

2.2.3 Amortization of Contributions in Aid of Construction

Consistent with past practice, the amortization rate for CIAC is calculated as a function of the depreciation rates for Transmission and Distribution plant, the asset types that CIAC is received for.

The recommended amortization rates of 2.11 percent[207] for Distribution CIAC and 1.46 percent[208] for Transmission CIAC is based on the average of the recommended depreciation rates for the Distribution Services, Mains and Meters/Regulators Installation costs and Transmission Pipeline and IP Transmission Pipeline. With the lower recommended rates for these asset classes, the amortization rates for CIAC will also be lower, resulting in a reduction to amortization of CIAC of approximately $0.3 million per year.

2.2.4 Average Life Group versus Equal Life Group

In this section, FEI responds to the directive in Order G-119-16 to evaluate the costs and benefits of converting to the Equal Life Group (ELG) depreciation method, as follows:

> FortisBC Energy Inc. is directed to include 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.

The two group depreciation procedures commonly used by utilities are:

1. the ALG, also referred to as Average Service Life (ASL); and
2. the Equal Life Group (ELG).

The ALG depreciation method calculates depreciation based on average service life for a component group of assets (one depreciation rate for the group) and is the depreciation method currently used by FEI for both financial reporting and rate setting.

The ELG procedure sub-divides an asset component group into sub-components of equal lives and depreciates each group separately using a weighted composite depreciation rate.

Based on its research and discussions with Concentric, FEI analyzed two options for converting to ELG and has estimated the costs and feasibility of each option. The estimates are preliminary in nature, given the uniqueness of the issue and the two options available to convert from ALG to ELG.

2.2.4.1 Option 1: Conversion to ELG without Componentization

In this option, an Iowa curve shape is used to determine the equal life groups for each vintage that depicts the retirement pattern that each group will experience. As described by

[207] For FEI Distribution CIAC the rate is calculated by dividing the sum of the depreciation for DS Services, Mains and Meter installation costs by the sum of their original cost at December 31, 2017.

[208] For FEI Transmission CIAC the rate is calculated by dividing the sum of the depreciation for Transmission Pipeline and IP Pipeline by the sum of their original cost at December 31, 2017.

Concentric[209], the ELG method develops a depreciation rate that includes specific weighting related to retirements that are expected to occur prior to and after the average service life of an account. For example, if an account has an average service life of 10 years, the ELG method will recognize that some investment is expected to retire in each of the years from year 1 through perhaps years 20 (depending on the Iowa curve shape). In this manner, a portion of the account is depreciated using a 100 percent rate for the investment expected to retire within the first year, and at a 50 percent rate for the investment expected to retire in the second year, and so on, through to the 20th year, where the investment expected to last to the 20th year is depreciated at a rate of 5 percent. Based on the investment that is expected to retire at each of the year 1 through year 20 age intervals, as described above, the ELG method develops a weighted average depreciation rate. In this way, using the specific estimated amount of investment to retire at each age interval, and the use of an average depreciation rate based on the expected amount to retire at each age interval, the ELG method produces a depreciation rate that incorporates fully depreciated assets that retire at each of the age intervals.

When an asset is retired, the most commonly used approach is to consider that, at the time of retirement, the asset is retired consistent with the expectations of the retirements used within the ELG depreciation rate calculations (i.e., the retirements are matching the Iowa curve used in the ELG calculations). If this approach is used, there is no gain or loss recognized at the time of retirement to either the income statement or any deferred accounts. However, with the use of this option of the ELG method, a test is normally prepared at the end of each fiscal year to determine if the actual retirement is appropriately matching the expected retirement pattern based on the Iowa curve.

To the extent that the actual retirements amounts by age would have been reasonably estimated in the Iowa curve used in the development of the depreciation rate, there would be no adjustment required (i.e., no loss or gains to be booked to either the income statement or any type of deferred account). While there will be virtually no possibility that the actual retirements will match exactly to the Iowa curve estimates, there is normally a range of variance that is considered reasonable (usually a total of 5 to 10 percent). Variances within this range are then dealt with in future depreciation studies. If there is a variance outside of the range, a gain or loss is recognized.

For this first option, the costs of converting from ALG to ELG, excluding the impact on depreciation and net salvage expense, are estimated at $0.1 to $0.2 million. The relatively low cost is due to the following:

- Concentric advises that the conversion to the ELG method would not require any changes to the datasets provided to Concentric. Additionally, the work required by Concentric to produce the depreciation rates is virtually the same as the development of the depreciation rates using the ALG method.

[209] Response to BCUC IR 1.2.1 - FEI’s Proposal for Depreciation and Net Salvage Rate Changes.

- The cost to update the new depreciation rates within SAP will be the same no matter which method is used, ALG or ELG. Because the input is a depreciation rate, FEI's SAP accounting system is not impacted by the fact that the rate is calculated using the ELG method.

However, Concentric's prior experience suggests that the regulatory burden increases when the ELG method is initially introduced as more information is often sought during the regulatory review process. Concentric's assistance will be required to respond to information requests or respond to intervener evidence, and Concentric may also be required to provide testimony if there is an oral hearing. Additionally, higher fees for Concentric are expected for assistance annually to perform the required year-end test discussed above.

2.2.4.2 Option 2: Conversion to ELG with Componentization

The second option requires a more extensive reconfiguration of the existing tracking requirements and systems. In this option, considerable work will be required to develop a system and procedures that track assets' vintage data in greater detail, including the age of the retirements and the accumulated depreciation reserve by vintage. Detailed vintage plant retirement data is required from which future retirement patterns can be estimated. This involves reviewing and analyzing existing asset classes and determining whether use of additional subclasses (i.e., components and componentization) and different retirement profiles may better reflect the lives of the assets, resulting in less gains/losses on retirement of the assets. Implementing at this level of detail will provide additional actual information of the company's assets (vintage activity and reserve data for each vintage) to better support the choice of the Iowa curves and assets' lives necessary in order to get the most accurate results possible. However, this may not be practical or cost effective as demonstrated below in terms of the estimated cost of conversion for this option. This compares to the first option where this level of detail is not required, and where the determination of a retirement profile is instead estimated based on matching of retirements against a chosen Iowa curve that best fits the retirement activities observed.

There is a divergence of opinions in the industry on whether such a level of detail and sophistication is required to properly implement the ELG method. This was reflected in the Manitoba Hydro 2014/15 & 2015/16 General Rate Application hearing in which Manitoba Hydro proposed the implementation of the ELG method for depreciation. During the proceeding, expert testimony was provided supporting the two different approaches to implementing ELG.[210] As a result of the proceeding, Manitoba Hydro was denied its request to implement ELG for rate setting.

For this second option, the estimated conversion costs to transition from the current ALG method to the ELG method, excluding the impact on depreciation and net salvage expense, is expected to be approximately $2 million. Given the uniqueness of the issue, FEI has relied

[210] Larry Kennedy from Gannett Fleming testifying on behalf of Manitoba Hydro and Patricia Lee from BCRI Inc. testifying on behalf of the Manitoba Power Industrial Users Group and The Coalition.

mostly on its internal assessment of the activities required and discussions with Concentric to develop the cost estimate for this option. As such, FEI considers the cost estimate preliminary in nature with the final cost estimate to be validated through engagement of external resources and/or obtaining quotations should a decision be made convert to the ELG method.

The details of the cost estimate are provided in Table D2-5 below.

Table D2-5: Estimated Cost to Implement ELG Depreciation Method for FEI ($ millions)

Activity	Estimated Cost (in $ millions)
Identify new asset components/asset classes and develop historical cost, vintage information and retirement profile, create new procedures, policies and guidelines, impact on operational efficiencies	$ 0.35
Concentric Advisors assistance in developing new depreciation rates	$ 0.25
Concentric Advisors assistance with regulatory support	$ 0.10
Asset conversion including: SAP system changes and testing, detailed review of historical plant records, re-allocating costs between existing and new components, staff training	$ 1.30
Total estimated cost for conversion	**$ 2.00**

The figures provided in Table D2-5 above are supported by the following comments:

- In its analysis to review Option 2, FEI found that it currently does not have the level of detail required in its financial records to implement the ELG method in this manner. In order to do so, FEI would need to undertake significant efforts including making changes to its SAP system. A significant amount of asset classes will need to be separated into a multitude of sub-asset accounts. For example, the Distribution Mains account will need to be separated into at least two new asset accounts: Distribution Mains steel pipe and Distribution Mains polyvinyl chloride (PVC). In addition, these two accounts would need to be further separated by time intervals (equal life groups), for example by ten-year time spans (1960-1969, 1970-1979, 1980-1989, etc.). FEI currently has a large number of asset classes (i.e., more than 100 asset classes) which would require more details to be tracked under the ELG method, making the asset tracking process laborious to manage.
- A significant amount of work will also be needed to analyse all historical data to allocate costs to the new components by installation date and to recapture historical asset retirement information to build new retirement profiles based on the new componentization. To perform this analysis, FEI would require consulting resources with support from FEI's asset accounting and operations staff. Additionally, processes, procedures and guidelines for asset accounting will need to be revised and new ones created.
- The SAP system changes required to support the tracking of asset activities include the creation of new asset classes and depreciation keys. Changes are also required to the

service order automatic settlement rule programs to reflect the new asset structures as well as designing, developing and testing of the process to perform the mass transfer of costs to the new assets and updates of the depreciation keys for existing assets. The effort necessary will be significantly impacted by the volume of data changes needed. Given the level of automation built into FEI's asset settlement process, extensive testing will also be required to ensure that the enhancements are working correctly.

2.2.4.3 Comparison of ELG and ALG

Under the ALG method:

- the depreciation rate is based on the average life of the assets;
- losses result from the retirements of assets prior to the average service life (i.e., under depreciated); and
- gains from the retirement of assets after the average service life (i.e., over depreciated) are observed.

In contrast, under the ELG method:

- asset classes are subdivided into a number of equal life groups;
- each equal group provides a specific representation and profile of the sub-group; and
- this eliminates the need to base depreciation on overall lives as is done using the ALG method.

The ELG method is theoretically more accurate because it depreciates the capital cost of an asset group in accordance with the consumption of the asset group providing service to customers. In this regard, FEI's customers are more appropriately charged with the cost of the assets consumed in providing them service during the applicable service period. The recovery of the assets' costs is accomplished by expensing the assets' cost during their service life, thereby reducing the risk of incomplete cost recovery. However, the total depreciation expense over the life of the assets is the same under both the ELG and ALG methods.

The ELG method results in higher depreciation expense earlier on in the assets' lives compared to the ALG method, and therefore may also result in a lower total return on rate base over the life of the assets. However, as outlined in FEI's response to BCUC IR 1.2.2 regarding FEI's Proposal for Depreciation and Net Salvage Rate Changes, the impact is difficult to quantify. Whether in fact there would be a lower total return would depend on how much the depreciation expense itself will be higher under the ELG method that recovers depreciation more quickly because the depreciation expense that is recovered from customers earlier is offset by the lower earned return under a method that recovers depreciation more quickly. The total lower earned return to be recovered from a lower rate base, however, would be influenced by a number of factors including asset addition and retirement patterns, depreciation rates, capital cost allowance rates, income tax rates, and cost of capital changes.

Table D2-6 shows the high-level impact on depreciation expense comparing ALG to the ELG method assuming no componentization is done (Option 1).

Table D2-6: Impact on Depreciation Expense of ALG vs ELG Depreciation Method for FEI ($ millions)

	ALG	ELG	Change
Depreciation	$ 169.0	$ 187.2	$ 18.2
Net Salvage	44.8	52.2	7.3
CIAC	(8.2)	(9.4)	(1.2)
Total	**$ 205.7**	**$ 230.0**	**$ 24.3**

Based on the amounts in the table above, the initial implementation of the change to the ELG method would result in a delivery rate increase of approximately four percent.

2.2.4.4 Group Depreciation Methods used by Other Utilities

Further to the BCUC directive to FEI to include a discussion of the group depreciation method used by each of the major regulated gas utilities in Canada, the following table provides a summary of the depreciation methods used for the gas utilities listed.

Table D2-7: Summary of Depreciation Methods Used by Large Canadian Natural Gas Distribution Utilities[211]

Utility	Depreciation Method	Proceeding	Accounting Standard
FortisBC Energy	ALG Procedure applied on a Remaining Life Basis	BCUC G-193-15	US GAAP
Pacific Northern Gas	ALG Procedure applied on a Remaining Life Basis	BCUC – G-151-18	US GAAP
Enbridge Gas Distribution Inc.	ALG Procedure applied on a Remaining Life Basis	EB-2011-0354 Decision on Settlement Agreement	US GAAP
Gazifere Inc.	ALG Procedure applied on a Remaining Life Basis	Regie De L'Energie D-2016-092	US GAAP

211 There is no approval order for SaskEnergy Inc., Heritage Gas Ltd. And Union Gas.

Utility	Depreciation Method	Proceeding	Accounting Standard
Manitoba Hydro - Centra Gas Manitoba Inc.	For Regulatory Accounting ALG Procedure applied on a Remaining Life Basis For Financial Reporting Equal Life Group Procedure applied on a Remaining Life Basis	Order No. 85/13	IFRS
AltaGas Utilities Inc.	Equal Life Group Procedure applied on a Whole Life Basis	AUC Decision 2012-091	US GAAP
SaskEnergy Inc.	Equal Life Group Procedure applied on a Whole Life Basis	2018 Depreciation Filing	IFRS
Energir (Gaz Metro)	Equal Life Group Procedure applied on a Remaining Life Basis	2015 Depreciation Filing	US GAAP
Heritage Gas Ltd.	Equal Life Group Procedure applied on a Remaining Life Basis	2011 Depreciation Filing	US GAAP
Union Gas	Equal Life Group Procedure by Generation Arrangement applied on a remaining Life Basis	EB 2005-0520 Exhibit D4 – Tab 4 – Schedule 1	US GAAP

Overall, approximately half of the ten large Canadian natural gas distribution utilities are using the ALG method. For the utilities using the ALG method, they are also reporting under the US GAAP accounting framework. For the utilities that are using the ELG depreciation method (i.e., Manitoba Hydro for financial reporting purposes only, and SaskEnergy), one of the reasons is that it is a more acceptable depreciation method for entities reporting under International Financial Reporting Standards (IFRS). IFRS requires a greater degree of componentization of assets; gains and losses on asset retirements are recognized into income immediately; and the costs of removal are recognized differently. The ELG method better satisfies these requirements and enables the utilities who report under IFRS for external reporting purposes to minimize the requirement to maintain two different depreciation methodologies for regulatory and external reporting purposes.

Pursuant to BCUC Orders G-183-14 and G-117-11, FEI sets its rates using US GAAP as an accounting framework, which is consistent with the use of the ALG method.

2.2.4.5 Proposal to Continue to use ALG

In summary, FEI proposes to continue with the use of the ALG depreciation method for the following reasons:

1. ALG is a practical method and continues to remain a widely accepted and utilized depreciation method by utilities in Canada.

2. ALG is an acceptable depreciation method under US GAAP which FEI is using as its accounting framework for financial reporting.
3. Both the ALG and ELG methods result in the full recovery of the costs of the assets over the lives of the asset accounts. The ELG method is intended to reflect the expected physical retirement of the assets in each year while the ALG method will, by design, result in an under depreciation for those assets in earlier years with a corresponding over depreciation during the latter years of the assets' lives.
4. Continuing with the use of the ALG method compared to the ELG method avoids the increase in the depreciation rate and expense and higher customer rates that immediately result from converting to the ELG method.
5. Since FEI performs ALG-based depreciation studies on a relatively frequent basis, such as every three to five years, any gains and losses accumulated in the short-term will be passed through customer rates in a timely basis. Performing ALG method depreciation studies on a relatively regular basis negates the theoretically increased accuracy that may be achieved through the ELG method, thus ensuring that customers bear the appropriate cost of service.

2.3 *2017 DEPRECIATION STUDY FOR FBC*

FBC implemented the depreciation and net salvage rates from the 2014 Depreciation Study effective January 1, 2016 pursuant to Order G-202-15. FBC's 2017 Depreciation Study, which is included in Appendix D2-2 has been prepared based on electric plant-in-service as of December 31, 2017. The overall results of the 2017 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, are compared to the overall results of the 2014 Depreciation Study and are shown in Tables D2-8 and D2-9 below. Implementation of the rates from the 2017 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $2.2 million per year, an approximate 0.12 percent overall increase in the composite depreciation rate compared to the current approved rates. The resulting increase to rates is less than one percent.

Table D2-8: Impact of Implementing Depreciation Study Recommendations for FBC ($ millions)

	Existing	Recommended	Change
Depreciation	$ 43.0	$ 43.2	$ 0.2
Net Salvage	$ 10.7	$ 12.6	$ 1.9
CIAC	$ (3.9)	$ (3.8)	$ 0.1
Total	**$ 49.8**	**$ 52.0**	**$ 2.2**

Table D2-9: Depreciation Study Average Rate Recommendations for FBC (percent)

	Existing	Recommended	Change
Depreciation	2.27%	2.28%	0.01%

Net Salvage	0.63%	0.74%	0.11%
Total	**2.90%**	**3.02%**	**0.12%**

Further discussion of the recommended changes by Concentric to the depreciation, net salvage and amortization of CIAC follows.

2.3.1 Depreciation Rates

The 2017 Depreciation Study was developed using the ALG depreciation methodology consistent with the previous 2014 Depreciation Study. The implementation of the recommended 2017 Depreciation Study rates results in an increase to the average composite depreciation rate for FBC from 2.27 percent to 2.28 percent. This results in total FBC depreciation expense increasing by approximately $0.2 million. This change excludes the effects on depreciation expense resulting from additions and retirements to PP&E as well as changes to the net salvage rates. The recommended depreciation rates, excluding the net salvage rates, are set out in Table D2-10 below.

Table D2-10: Impact of Implementing Recommended Depreciation Rates for FBC

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
1	330.10	Land Rights	2.60%	1.07%	24,995	10,287	(14,708)
2	331.00	Structures and Improvements	1.19%	1.38%	216,764	251,373	34,609
3	332.00	Reservoirs, dams and waterways	1.50%	1.41%	509,878	479,285	(30,593)
4	333.00	Water wheels, turbines and generators	1.45%	1.36%	1,414,752	1,326,940	(87,812)
5	334.00	Accessory electrical equipment	1.77%	2.25%	763,537	970,598	207,061
6	335.00	Other power plant equipment	1.79%	1.75%	805,859	787,851	(18,008)
7	336.00	Roads, railroads and bridges	1.47%	1.44%	18,925	18,539	(386)
8	350.20	Surface and mineral	1.23%	1.27%	100,528	103,798	3,270
9	353.00	Substation equipment	1.79%	1.68%	4,153,628	3,898,377	(255,251)
10	355.00	Poles, towers and fixtures	1.89%	1.64%	2,100,824	1,822,937	(277,887)
11	356.00	Conductors and devices	1.93%	1.77%	2,089,629	1,916,396	(173,233)
12	359.00	Roads and trails	2.88%	1.96%	32,312	21,990	(10,322)
13	360.20	Surface and mineral	1.23%	1.25%	139,236	141,500	2,264
14	362.00	Substation equipment	1.92%	1.84%	4,647,432	4,453,789	(193,643)
15	364.00	Poles, towers and fixtures	1.84%	1.75%	3,786,453	3,601,246	(185,207)
16	365.00	Conductors and devices	1.98%	1.54%	6,576,074	5,114,724	(1,461,350)
17	368.00	Line transformers	2.29%	2.31%	3,495,489	3,526,017	30,528
18	369.00	Services	0.50%	0.51%	47,609	48,561	952

Line #	Class	Description	2014 Depreciation study Rate	2017 Depreciation study Rate	Depreciation Based on 2014 Depreciation study Rate	Depreciation Based on 2017 Depreciation study Rate	Increase + / Decrease -
19	370.00	Meters	6.68%	6.68%	3,565	3,565	-
20	370.10	AMI Meters	5.00%	6.25%	1,873,045	2,341,306	468,261
21	373.00	Street lighting and signal systems	4.13%	4.06%	519,410	510,607	(8,803)
22	390.10	Structures-Masonry	3.20%	2.37%	1,391,734	1,030,753	(360,981)
23	390.20	Operations Building	2.14%	1.50%	310,362	217,543	(92,819)
24	391.00	Office furniture and equipment	1.68%	4.42%	94,626	248,956	154,330
25	391.10	Computer Hardware	9.85%	21.60%	1,166,529	2,558,075	1,391,546
26	391.20	Computer Software	6.17%	8.96%	2,265,642	3,290,138	1,024,496
27	391.60	AMI Computer Software	10.00%	10.00%	959,741	959,741	-
28	392.10	Light Duty Vehicles	6.27%	4.79%	299,072	228,478	(70,594)
29	392.20	Heavy Duty Vehicles	5.86%	6.50%	1,311,989	1,455,278	143,289
30	394.00	Tools and work equipment	2.49%	4.11%	219,335	362,036	142,701
31	397.00	Communications structures and equipment	5.49%	2.84%	719,786	372,349	(347,437)
32	397.10	Fiber	5.49%	6.97%	658,558	836,092	177,534
33	397.20	AMI Communications structures and equipment	6.67%	6.67%	331,481	331,481	-
34		**Total Annual Depreciation**			**43,048,799**	**43,240,606**	**191,807**
35							
36		**Annual Composite Rate**			**2.27%**	**2.28%**	

Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2018 gross asset values.

The asset categories that account for the majority of the forecast change in depreciation expense are Distribution Conductors and Devices (365), and the two General Plant accounts Computer Hardware (391.10) and Computer Software (391.20). Each of these are discussed below. Refer to pages 3-3 to 3-15 of the Concentric study included in Appendix D2-2 for further discussion.

2.3.1.1 Distribution Conductors and Devices (365)

For Distribution Conductors and Devices (365), Concentric recommends a 55-year life, an increase from the 49 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 55 years is more reflective of the historic retirement activity and falls within the typical range of lives used for this account by peer utilities which are 40 to 65 years. In discussions with engineering staff, Company expectations were that an average service life of less than 65 years is appropriate. The recommended longer life of the Distribution Conductors and Devices and the true-up of the depreciation rate over the remaining life of the assets result in a decrease of 0.44 percent in the depreciation rate for this asset category.

2.3.1.2 General Plant Accounts

For certain General Plant accounts, Concentric has recommended and used amortization accounting to develop the depreciation rates, representing a change from the current approach of tracking and retiring individual assets. Amortization accounting is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset to which it applies. Use of the amortization method of accounting generally includes the retirement of the assets in the accounts at the expiry of the amortization period. As such, no asset is retired prior to the expiry of the period and all assets are retired at the end of the period, regardless of when the items are physically removed from service. The use of amortization accounting for these asset classes is consistent with the FEI practice and used widely by electrical and gas utilities.

The accounts listed below where amortization accounting is recommended represent numerous units of property, but a very small portion of depreciable electric plant in service.

370.10 AMI Meters	18 years
391.00 Office Furniture and Equipment	15 years
391.10 Computer Hardware	4 years
391.20 Computer Software	8 years
391.60 AMI Computer Software	10 years
394.00 Tools and Work Equipment	15 years
397.00 Communication Structures and Equipment	15 years

As part of the transition to the amortization accounting approach for these assets, the costs for assets older than the recommended amortization period were retired along with their accumulated depreciation balances. The result was changes in the allocation of costs from the original costs to accumulated depreciation to recognize the retirements but with no change in the net rate base amounts for these assets.[212]

To provide an order of magnitude to the accounts affected, the table below contains the balances for the asset classes affected by the change to amortization accounting[213].

[212] For further discussion, refer to page 4-2 of Appendix D2-2 FBC Depreciation Study.
[213] Excluding the two AMI accounts listed above.

Table D2-11: Asset Class Balances Converting to Amortization Accounting ($000s)

Asset class	Asset Class Description	Cost Dec 31, 2017	Accum Depr Dec 31, 2017	NBV
391.00	Office Furniture and Equipment	5,632	(2,378)	3,254
391.10	Computer Hardware	11,843	(4,030)	7,813
391.20	Computer Software	36,720	(18,363)	18,358
394.00	Tools and Work Equipment	8,809	(5,308)	3,500
397.00	Communications Structures and Equipment	13,111	(9,684)	3,427

The asset classes that account for the biggest change in the depreciation rates as a result of amortization accounting are Computer Hardware (391.10) and Computer Software (391.20).

2.3.1.2.1 COMPUTER HARDWARE (391.10)

For Computer Hardware (391.10), Concentric recommends a change from five to four year useful life consistent with the useful life used by FEI. The change is primarily due to discussions with information systems management indicating that on average the total life expectancy of computer hardware is four years or less. The shortening of the computer hardware asset life by one year and moving to amortization accounting results in an increase of approximately 11.75 percent in the depreciation rate for this asset category.

2.3.1.2.2 COMPUTER SOFTWARE (391.20)

For Computer Software (391.20) Concentric recommends an eight -year life which is consistent with the previous study. The recommended amortization accounting for this asset category and the true-up of the depreciation rate over the remaining life of the assets result in an increase of approximately 2.79 percent in the depreciation rate for this asset category.

The adoption of the depreciation rates as outlined in the current depreciation study is necessary in order to properly reflect the assets' useful lives and a fair allocation and recovery of depreciation expense between current and future ratepayers.

2.3.2 Net Salvage

As approved by the BCUC in Order G-202-15, FBC provides for net salvage (removal costs less salvage proceeds) on its existing assets as a cost of providing service, recovered from customers over the useful life of the asset.

The current 2017 Depreciation Study includes updated estimates of net salvage rates which FBC has included in depreciation expense.

The updated net salvage rates based on electric plant-in-service as of December 31, 2017 is included in Appendix D2-2, Section 5 of the 2017 Depreciation study.

The asset classes where net salvage is included are shown in Table D2-12, comparing the recommended and existing net salvage rates and the impact on net salvage expense (i.e., depreciation expense). As recommended by the 2017 Depreciation study, the average composite net salvage rate increases from 0.63 percent to 0.74 percent using the recommended rates. The recommended net salvage rate increase is primarily driven by the increases in FBC's actual cost of removal activities. This change results in an increase to net salvage expense of approximately $1.9 million.

1 **Table D2-12: Net Salvage Rates by Asset Class for FBC**

Line #	Class	Description	Net Salvage 2014	Net Salvage 2017	2014 Depreciation study Net Salvage Rate	2017 Depreciation study Net Salvage Rate	Net Salvage Based on 2014 Rate	Ney Salvage Based on 2017 Rate	Increase + / Decrease -
1	331.00	Structures and Improvements	-5%	-10%	0.10%	0.30%	18,215	54,646	36,431
2	332.00	Reservoirs, dams and waterways	-15%	-25%	0.28%	0.49%	95,177	166,560	71,383
3	333.00	Water wheels, turbines and generators	-20%	-25%	0.34%	0.43%	331,735	419,547	87,812
4	334.00	Accessory electrical equipment	-20%	-20%	0.51%	0.88%	220,002	379,612	159,610
5	335.00	Other power plant equipment	-10%	-15%	0.26%	0.37%	117,052	166,574	49,522
6	353.00	Substation equipment	-25%	-25%	0.66%	0.65%	1,531,505	1,508,301	(23,204)
7	355.00	Poles, towers and fixtures	-25%	-35%	0.64%	0.88%	711,390	978,161	266,771
8	356.00	Conductors and devices	-25%	-30%	0.59%	0.75%	638,799	812,032	173,233
9	362.00	Substation equipment	-25%	-30%	0.65%	0.77%	1,573,349	1,863,814	290,465
10	364.00	Poles, towers and fixtures	-30%	-35%	0.83%	0.98%	1,708,020	2,016,698	308,678
11	365.00	Conductors and devices	-30%	-35%	0.91%	0.84%	3,022,337	2,789,849	(232,488)
12	368.00	Line transformers	-15%	-25%	0.45%	0.82%	686,886	1,251,660	564,774
13	373.00	Street lighting and signal systems	-10%	-15%	0.52%	0.89%	65,398	111,931	46,533
14	390.10	Structures - Masonry		-5%	0.00%	0.16%	-	69,587	69,587
15	390.20	Operations Buildings		-5%	0.00%	0.13%	-	18,854	18,854
16	392.10	Light Duty Vehicles	25%	15%	0.00%	-0.98%	-	(46,745)	(46,745)
17	397.00	Communications structures and equipment	0%	0%	0.00%	0.60%	-	78,665	78,665
18		**Total Annual Net Salvage**					**10,719,866**	**12,639,746**	**1,919,880**
19									
20		**Annual Composite Rate**					**0.63%**	**0.74%**	**0.11%**

2 Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2018 gross asset values.

Overall, the 2017 Depreciation Study results in a recommended combined depreciation and net salvage rate of 3.02 percent (depreciation of 2.28 percent plus net salvage of 0.74 percent), which is slightly higher than the existing composite depreciation rate of 2.90 percent.

2.3.3 Amortization of Contributions in Aid of Construction

The amortization rate for CIAC is calculated as a function of the depreciation rates for Distribution plant, which is the asset type for which CIAC is received.

Consistent with past practice, the recommended amortization rate of 2.00 percent for Distribution CIAC is based on the average of the recommended depreciation rates for the Distribution Poles, Towers and Fixtures, Distribution Conductors and Devices, Distribution Line Transformers and Distribution Meters plant. With the lower recommended rates for these asset classes, the amortization rates for CIAC will also be lower resulting in a reduction to amortization of CIAC of approximately $0.1 million per year.

2.4 *CONCLUSION*

The adoption of the depreciation rates as outlined in the current FEI and FBC 2017 Depreciation Studies is necessary in order to properly reflect the assets' useful lives and a fair allocation and recovery of depreciation expense between current and future ratepayers.

For FEI, implementation of the rates from the FEI 2017 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $3.5 million per year, a 0.08 percent overall increase to the composite depreciation rate compared to the current approved rates. The resulting increase to the delivery rate is less than one percent.

For FBC, implementation of the rates from the FBC 2017 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $2.2 million per year, an approximate 0.12 percent overall increase to the composite depreciation rate compared to the current approved rates. The resulting increase to rates is less than one percent.

Additionally, as directed by the BCUC, FEI has completed research of the group depreciation method used by each of the major regulated gas utilities in Canada and completed the 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.

In summary, FEI believes it is appropriate to continue with the use of the ALG depreciation method as it is a practical method that is widely accepted in Canada. The research indicates that approximately half of the ten large Canadian natural gas distribution utilities are using the ALG method, while the remaining utilities have adopted ELG as the ELG method better satisfies the requirements under IFRS for external reporting purposes. The ALG method is an acceptable depreciation method under US GAAP, and like the ELG method will result in the full recovery of the assets over the lives of the asset accounts. In addition, continuing with the use of the ALG method avoids the increase in the depreciation rate and expense and higher customer rates that result from converting to the ELG method.

3. LEAD-LAG STUDY FOR CASH WORKING CAPITAL

3.1 *INTRODUCTION AND SUMMARY*

In this Application, FortisBC is requesting approval to adopt updated lead-lag days as determined in the 2018 Lead-Lag Studies in Appendix D3-1 for FEI and Appendix D3-2 for FBC. The updated lead lag days will be used for the calculation of the cash working capital requirements in the FEI and FBC Annual Review for 2020 Rates Applications and in future rate applications until another lead-lag study is performed either at the request of the BCUC or FEI and FBC apply to refresh the approved lead-lag days based on more recent information.

Cash working capital is defined as the average amount of capital provided by investors in a 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, and are supported by a lead-lag study. The study recognizes that there are timing differences between when FEI and FBC provide 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 which is added to rate base; 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, a reduction to rate base.

The methodology and approach used to determine each of the individual components of the 2018 Lead-Lag Studies are included in Appendix D3-1 for FEI and Appendix D3-2 for FBC, with the methodology results of the studies summarized below. Consistent with the traditional approach in Canada and FEI's past lead-lag studies, FEI and FBC's 2018 studies include only cash operating expenditures, whereas depreciation, interest and equity return are excluded from the lead lag studies and the calculation of cash working capital. In this Application FBC's lead/lag methodology has been modified to be consistent with the FEI methodology in order to achieve alignment across the FortisBC Utilities (please see more details in Section D3.2 below).

3.2 *2018 LEAD-LAG STUDY FOR FEI*

FEI's 2018 Lead-Lag Study is included in Appendix D3-1. The following is a summary of the methodology and results of the study.

Summary of Methodology

- The study used 2017 actual data to perform the analysis, which was the most recent full year of available actual data. The actual data was then used to derive the "Proposed Lead Lag Days" in the table below.
- The study is similar in scope and methodology to FEI's previous study performed in 2009.
- The results of the study using the new lead and lag days have been compared to the results using the lead and lag days derived in the 2009 study.

Summary of Results

- When applied to 2019 approved data, the 2018 Lead-Lag Study results in a net lag of 5.5 days. This compares to a net lag of 6.2 days, as shown in the FEI Annual Review for 2019 Delivery Rates – Compliance Filing filed with the BCUC January 30, 2019[214], which uses the 2009 lead-lag day study results.
- This difference of 0.7 days is the result of a 1.7 day increase in expenditure lead days, partially offset by a 1.0 day increase in revenue lag days. The increase in expenditure lead days is primarily attributable to a longer service lead for O&M expenditures and provincial sales tax (PST), partially offset by a shorter service lead for operating fees.
- When applied to the forecasted revenues and operating expenses for 2019, this change in net days would have resulted in a decrease of approximately $2.0 million in cash working capital ($4.8 million decrease from expenses partially offset by a $2.8 million increase from revenues).

A summary of the results of the lead-lag study for FEI is presented in the table below.

[214] Appendix A, Schedule 14, Line 26, Column 5.

Table D3-1: Summary of FEI lead-lag study results

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							

3.3 *2018 LEAD-LAG STUDY FOR FBC*

FBC's 2018 Lead-Lag Study is included in Appendix D3-2. The following is a summary of the methodology and results of the study.

Summary of Methodology

- The study used 2017 actual data to perform the analysis, which was the most recent full year of actual available data. The actual data was then used to derive the "Proposed Lead Lag Days" in the table below.
- The study is similar in scope and methodology to the FEI lead-lag study and has sought to align the various cash working capital items with FEI's approach where possible. In particular, FBC has included goods and services tax (GST) in the cash working capital calculations in this study to align with the existing approved FEI presentation 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. FBC has also excluded interest expense in this study as a further element of alignment with FEI's methodology and consistency with the traditional approach used by other utilities in Canada. In addition, FBC used actual

revenue and expense data in this study which results in more accurate lead lag days compared to the high level assumptions used in the previously approved method.

- The results of the study have been compared to the previously approved method.

Summary of Results

- When applied to 2019 data, the 2018 Lead Lag Study results in a net lag of 9.5 days. This compares to a net lag of 6.7 days, as shown in the FBC Annual Review for 2019 Rates – Evidentiary Update[215],, which uses the previous lead-lag day study results.
- This difference of 2.8 days is the result of a 3.4 day increase in revenue lag days, partially offset by a 0.6 day increase in expenditure lead days. The increase in revenue lag days is primarily due to an increase in lag days for sales revenue customers and increased lag days in Apparatus and facilities rental revenue. This was partially offset by an increase in expenditure lead days primarily due to a longer payment lead for power purchases.
- When applied to the forecasted revenues and operating expenses for 2019, this change in net days would have resulted in an increase of approximately $1.3 million in cash working capital ($1.6 million increase from revenues partially offset by a $0.3 million decrease from expenses).

A summary of the results of the lead-lag study for FBC is presented in the table below.

[215] Dated October 3, 2018, Exhibit B-2-2, Appendix A, Schedule 14, Line 38, Column 5.

Table D3-2: Summary of FBC lead-lag study results

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							

4. SHARED SERVICES STUDY

4.1 INTRODUCTION

In this section, FortisBC reviews its shared services model approach to cross charging between FEI and FBC, and proposes to move to allocate costs based on cost drivers (Cost Driver Approach), as opposed to the current approach of charging time between the Companies based on timesheets (Timesheet Approach).

The following provides background information on the sharing of resources between FEI and FBC, describes the existing Timesheet Approach and a Cost Driver Approach to allocating shared services costs between FEI and FBC, and explains that the Cost Driver Approach is simpler to understand, easier to administer and more efficient, and more stable over time. Using 2018 actuals, a Cost Driver Approach results in a total allocation of shared resources between the Utilities that is similar to the Timesheet Approach currently in use. Further details are provided in the Shared Services Study in Appendix D4.

4.2 BACKGROUND

FEI and FBC have been sharing resources since 2010 for the benefit of both Companies and their customers. The sharing of resources started with the sharing of the Executive Management Team. The costs of the Executive Management Team are allocated between FEI and FBC using the approved Massachusetts Formula.

The sharing of resources has expanded in recent years as the departments in the two Companies integrate their operations and information technology platforms. Shared Services in support of O&M activities by function now 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. These costs are currently charged between the two Companies using a cross charge process based on timesheets (Timesheet Approach).

In the FEI All-Inclusive Code of Conduct and Transfer Pricing Policy proceeding, FEI indicated that it would continue to use its current cross charging approach until it reviewed the feasibility of a shared services model approach, and that it anticipated filing the results of its review in an annual review or RRA. 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.*" The Shared Services Study in compliance with this directive is included in Appendix D4 of the Application. The results of the study are summarized below.

4.3 TIMESHEET APPROACH

As noted above, except for Executive Management Team time, shared services costs have been charged between FEI and FBC using the Timesheet Approach. The Timesheet Approach utilizes a cross charge process based on timesheets, with the cross charges including fully loaded wages including benefits and time away, with no overhead or a facilities fee assigned. The Timesheet Approach requires staff to record their time and associated labour dollars to the affiliate for hours of service provided on a weekly basis.

Table D4-1 below outlines the extent of the 2018 Actual O&M Shared Services between FEI and FBC under the Timesheet Approach.

Table D4-1: 2018 Actual O&M Shared Services – Timesheet Approach

(in millions)	Gross O&M Actual	FEI to FBC Cross Charge	FBC to FEI Cross Charge	Net Cross Charge	Net O&M Actual
FEI	275.13	(2.55)	3.94	1.38	276.51
FBC	58.74	2.55	(3.94)	(1.38)	57.36
Total	**333.87**	**0.00**	**0.00**	**0.00**	**333.87**

For 2018, FEI charged FBC approximately $2.55 million for O&M Shared Services with FBC charging FEI approximately $3.94 million. The impact of the allocations between FEI and FBC is $1.38 million in higher O&M Shared Services for FEI with an offsetting decrease for FBC.

4.4 COST DRIVER APPROACH

An alternative approach to allocate O&M costs between FEI and FBC for shared services is a Cost Driver Approach. A Cost Driver Approach starts with identifying and quantifying the amount of resources that are considered shared. These shared resources are then pooled and allocated using allocation drivers that are reflective of the cause (i.e., “driver”) of the costs incurred. The Cost Driver Approach is consistent with successful Shared Service arrangements used in the past between FEI the Vancouver Island and Whistler utilities prior to their amalgamation in 2015, and the model currently in place between FEI and the Fort Nelson service area. Pacific Northern Gas Limited (PNG) also uses a Cost Driver Approach for the recovery of a number of operational, administrative, accounting, regulatory and other services to the various divisions at PNG. The shared services costs are allocated using a number of cost allocators including time, number of customers, number of employees and rate base.

Compared to the existing Timesheet Approach, the Cost Driver Approach is more efficient to administer while providing an allocation methodology that reasonably represents the sharing of resources. A Cost Driver Approach would require minimal timesheets / journal entries to be processed, and the cost drivers would require only annual updating with a broader review of the shared services model on a longer-term basis.

Examples of cost drivers (i.e., allocation factors) for FortisBC include number of customers, number of employees, Massachusetts formula, and management time estimates. To determine the appropriate cost drivers to use, a review of both FEI and FBC departments/functions was conducted, which included interviews with department/function directors and managers. In the interviews, shared resources and allocation drivers were identified.

Table D4-2[216] below summarizes the results of the analysis using the Cost Driver Approach, resulting in a net allocation from FBC to FEI of $1.0 million.

Table D4-2: Proposed Cost Allocation Drivers ($000s)

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 (i.e., Identified Shared Costs (1)). The information contained in the "Allocation Basis (2)" section of the table are the cost drivers identified. The cost drivers provide an allocation methodology that reasonably represents the sharing of resources, allocating the Shared Resource Pool of $32.8 million between FEI and FBC. Applying the cost driver allocation percentages by department/function to the Shared Resource Pool of $32.8 million, the result is the Shared Resource Pool allocated by department/function for the two Companies (Allocated Shared Costs (3)). 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.

For comparison, under the section of the table identified as "Difference (4)", the resulting changes by department/function for FEI's and FBC's portions of the Shared Resource Pool are reflected in the last two columns in the table. Overall, applying the cost drivers, FEI's portion of the Shared Resource Pool increases by $1.0 million from $25.4 million to $26.4 million, with FBC's portion of the Shared Resource Pool decreasing the equivalent amount from $7.4 million to $6.4 million.

216 Appendix D4, Figure D4-7

4.5 TIMESHEET APPROACH VS. COST DRIVER APPROACH

Table D4-3 below outlines the extent of the 2018 Actual O&M Shared Services between FEI and FBC under the Cost Driver Approach in comparison to that under the existing Timesheet Approach.

Table D4-3: 2018 Actual O&M Shared Services – Cost Driver Approach vs Timesheet Approach

(millions)	O&M Actual Timesheet Approach	O&M Actual Cost Driver Approach	Allocations as per Timesheet Approach	Allocations as per Cost Driver Based	Difference in Approaches
FEI	276.51	276.17	1.38	1.04	0.34
FBC	57.36	57.70	(1.38)	(1.04)	(0.34)
Total	**333.87**	**333.87**	**0.00**	**0.00**	**0.00**

The "O&M Actual Timesheet Approach" column contains the total 2018 O&M actuals for FEI and FBC including cross charges under the existing Timesheet Approach. Refer to Table D4-1 above for a summary of the Timesheet Approach.

Using a Cost Driver Approach (the "O&M Actual Cost Driver Approach" column) results in a similar net allocation for shared O&M services between FEI and FBC. Using 2018 actuals, allocations under a Cost Driver Approach are $1.04 million net to FEI compared to $1.38 million net to FEI under a Timesheet Approach, for a difference of $0.34 million.

4.6 CONCLUSION

FortisBC recommends adopting the Cost Driver Approach. The Cost Driver Approach is simpler to understand, easier to administer and more efficient, and more stable over time, requiring only annual updating with a broader review of the shared services model undertaken on a periodic basis.

As shown in Table D4-3 above, the change in approach would have a minimal impact on FEI's and FBC's O&M costs. However, as part of the transition to a Cost Driver Approach in this Proposed MRP, an adjustment is required to the Base O&M of FEI and FBC to recognize the difference in the overall allocation from the current Timesheet Approach to 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.

5. CORPORATE SERVICES STUDY

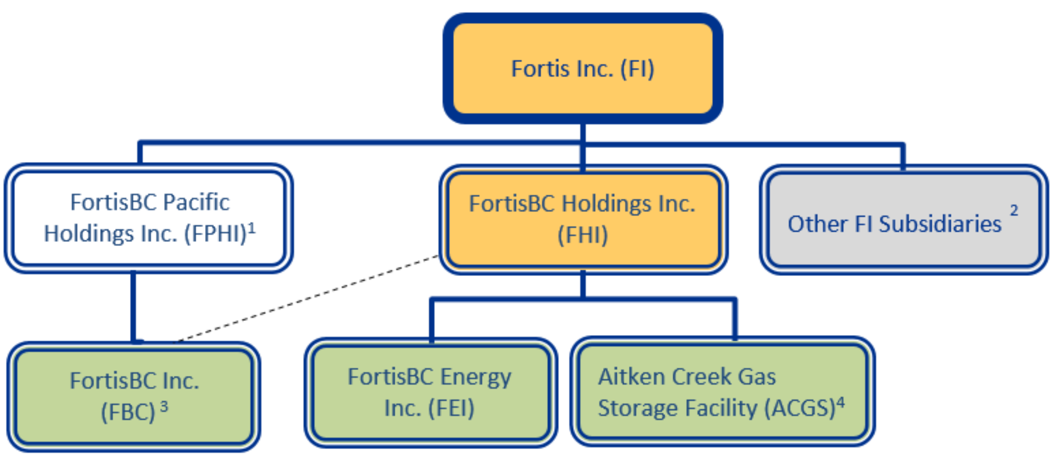
5.1 *INTRODUCTION*

In this Application, FortisBC is requesting approval of the methodologies of allocating common corporate service costs from FI and FHI to FEI and FBC. The allocation methodologies include a formula that is based on total assets, excluding goodwill, and controllable operating expenses for FI corporate services, and the use of a Massachusetts Formula for FHI corporate service allocations. Both methodologies and the nature of the FI and FHI corporate service costs were reviewed and endorsed by KPMG in the 2018 Corporate Service Study (2018 CS Study) included in Appendix D5. FortisBC is seeking approval of the allocation methodology, rather than the forecast of corporate service costs. The actual costs and allocation percentages will vary each year of the Proposed MRP depending on the size of the eligible corporate cost pool at FI and FHI, as well as the relative size of the FI and FHI allocators.

The corporate services function consists of certain specialized functions that reside in FI and FHI. FI provides corporate service functions for FHI and then FHI passes along a majority of these activities to FEI, FBC and the Aitken Creek Gas Storage ULC (ACGS), along with FHI corporate services. As a result, both FI and FHI provide expertise and corporate services to FEI, FBC and ACGS, resulting in economies of scale to those three companies. FortisBC engaged KPMG to review the nature and allocation of FI and FHI corporate services to FEI, FBC and ACGS to be implemented beginning 2020. KPMG's report is included in Appendix D5.

In Figure D5-1 below, the entities that provide the corporate services (FI and FHI) are in the yellow boxes and the BCUC-regulated entities that share in the corporate services (FBC, FEI and ACGS) are in the green boxes.

Figure D5-1: 2018 Corporate Services Study Organizational Chart



Notes:

[1] FPHI is not regulated by the BCUC and does not receive corporate services from either FI or FHI. While FPHI is the legal parent of FBC, it has no employees and provides no services to FBC. FPHI does have contracts in

place to provide operation and management services to non-regulated third party generation owners. These non-regulated services utilize resources provided by FBC, which are charged through to FPHI in accordance with the Code of Conduct and Transfer Pricing Policy, meaning that regulated FBC customers receive the benefit of a margin on such services.

[2] Other FI subsidiaries that benefit from FI corporate services and therefore are included in the allocation include CH Energy Group, UNS Energy Corp., ITC Holdings Corp, FortisAlberta, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, and Fortis Turks and Caicos.

[3] While FBC is a direct subsidiary of FPHI, it receives corporate services from FHI and therefore is considered as part of the sharing allocation pursuant to the 2018 CS Study.

[4] ACGS is directly owned by FortisBC Midstream Inc. (FMI) and FMI is directly owned by FHI. FMI has been removed from the above organizational structure to provide a simpler view of the corporate service allocations.

The 2018 CS Study reflects the FI and FHI eligible corporate costs included in a pool that are then charged to FEI, FBC and ACGS by way of the Massachusetts Formula. The methodology used to allocate FHI eligible corporate service costs to FEI, FBC and ACGS is one of the primary focuses of the 2018 CS Study.

The sections below review the changes in the 2018 CS Study compared to the 2013 Corporate Services Study (2013 CS Study), and then describe the corporate services provided by FI and FHI and how the costs of the corporate services are aggregated and allocated to FEI, FBC and ACGS.

5.2 *REVIEW OF CHANGES SINCE 2013 CORPORATE SERVICES STUDY*

FEI's last corporate services study was in 2013 and was approved by Order G-138-14. The nature of the FI and FHI corporate services that are incurred for the benefit of FEI and FBC remain consistent with the 2013 CS Study.

The changes included in the 2018 CS Study as compared to the 2013 CS Study are as follows:

- The amalgamation of the three gas utilities (FEI, FEVI. and FEW), effective December 31, 2014, means that corporate services from FI and FHI are no longer allocated to three regulated gas utilities.
- ACGS and FBC have been added to the sharing methodology of FI and FHI corporate service costs.
  - FI and FHI have been providing corporate services to ACGS since its acquisition in 2016 consistent with the corporate services provided to FEI and FBC. Included in BCUC information request 1.14.4 for the Application for Approval to Acquire the Shares of ACGS in January 2016, FEI stated that "once the business is stable and operating for a period of time, the Massachusetts Formula would be considered" when referring to the cost allocation methodology for FHI corporate services to ACGS.

- Similarly, FI and FHI have been providing corporate services to FBC since 2011; however, the costs have been direct charged rather than using a cost sharing methodology.

- FI corporate service costs previously charged directly to FBC have been pooled with the FI corporate service costs charged to FHI.
- FHI corporate service costs previously charged directly to FBC have been pooled with the FHI corporate service costs charged to FEI and ACGS

While there have been changes to the entities receiving shared services, the general process, nature of eligible corporate service costs and allocation methodology of corporate services from FI and FHI is consistent with the 2013 CS Study. FortisBC will continue to rely on these corporate services during the term of the Proposed MRPs.

5.3 *DESCRIPTION OF FI CORPORATE SERVICES*

5.3.1 FI's Stand-Alone Business Operating Model

FI is a holding company which, directly or indirectly, owns utility operations in nine U.S. states, five Canadian provinces and three Caribbean countries. FI has a stand-alone business operating model, whereby its subsidiaries operate substantially autonomously from FI and each other. Each operating subsidiary is responsible for its own operations and regulatory activities. Since FI is a public holding company, its business operations are different than those of its operating subsidiaries. FI activities are in support of its ability to provide and maintain equity investment in the operating subsidiaries and provide a market return to its widely held shareholder base. In addition, FI provides strategic oversight, strategic planning and corporate governance, as well as managing and administering the group-wide insurance program and the coordination of cross-functional sharing of best practices across the operating subsidiaries.

While FI provides these services, each operating subsidiary has its own board of directors and executive management team based in the area served by the subsidiary. The subsidiary executive management is accountable to its own board of directors and responsible for key aspects of utility operations such as safety, customer satisfaction, service continuity, environment and sustainability impacts, cost management, financial performance and community involvement. The subsidiary executive and management teams also determine human resource requirements and hiring practices, negotiate collective bargaining agreements, establish operating and capital budgets, and serve as the direct contact and decision-making authorities in regulatory matters. With this structure and operating philosophy, FI has a relatively low number of employees and level of operating costs.

5.3.2 FI Functional Areas and Corporate Services

The functional areas of FI used to provide corporate services include the board of directors, executive, financial reporting, treasury and taxation, legal, planning and forecasting, internal audit, insurance/risk management, investor relations, human resources, communications and corporate affairs, information systems and cyber security. These functional areas support the following overarching business activities of FI:

- Maintain and provide additional equity to operating subsidiaries, by raising equity through the Canadian and US public capital markets;
- Compliance with public company securities requirements, resulting from being registered with the Ontario Securities Commission and U.S. Securities and Exchange Commission and listing on TSX and NYSE, which compliance is required to support its equity investment in the operating subsidiaries;
- Provide strategic oversight and coordinating and sharing best practices among the FI group of companies; and
- Administering the company-wide group insurance program.

The majority of the operating costs for each of the FI functional areas to provide these corporate services are recovered from its operating subsidiaries.

The nature of these functional area operating costs and corporate services are consistent with those provided by FI to FEI (by way of the FHI management fee) and FBC since the 2013 CS Study. The 2013 CS Study was approved by the BCUC for recovery over the terms of the Current PBR Plans for FEI and FBC.

5.3.2.1 Benefits of Provision of Equity Capital by FI

FI is listed on the TSX and NYSE. The liquidity of FI's stock in both Canada and the U.S., together with its dividend reinvestment plan (DRIP) and other share plans, provides a large and robust equity platform for its utility operations to draw upon. The group of FI's operating subsidiaries is diversified and multi-jurisdictional, and are primarily regulated electric and natural gas companies with deep expertise and experience across the group. FI's diversified portfolio of regulated electric and gas utilities allows FI to access capital markets on a cost efficient and effective basis. The operating subsidiaries benefit from FI's financial strength and access to capital markets as it allows them to obtain and maintain sufficient and cost-effective capital to meet their individual operational needs.

The operating subsidiaries benefit from the services provided, as the equity maintained and supplied by FI is required to ensure that the operating subsidiaries' capital structures are consistent with those approved by their respective regulators. Specifically, FEI and FBC obtain debt to finance their approved capital structures, while FI provides the remaining required equity financing. As a result of providing this equity financing, FI's operating subsidiaries are allocated a portion of FI's operating costs. If FI did not supply the necessary equity capital, the operating subsidiaries would have to obtain the equity capital from other sources individually and incur the associated costs. FI utilizes the public markets to access the equity needed in support of its operating subsidiaries, provides shareholder relations services, and ensures overall corporate governance requirements of equity market regulators are effectively met for the operating subsidiaries. FEI and FBC as the regulated utility entities will require incremental equity financing provided by FI in order to fund their regular capital expenditures, major projects and CPCNs over the course of the Proposed MRPs.

5.3.2.2 Benefits of Strategic Oversight and Sharing of Best Practices from FI

The operating subsidiaries benefit from the strategic oversight and sharing of best practices across the group of FI companies. The strategic oversight provided by FI enhances the corporate governance at the local operating subsidiary level while still allowing each operating subsidiary the ability to manage its local operations and make key business decisions in a substantially autonomous manner. The sharing of best practices allows each operating subsidiary to leverage the cumulative knowledge and experience of its affiliated subsidiaries, and occurs across many functional areas, including operations, human resources, customer service, communications, financial reporting, planning and forecasting, information technology, cyber security, legal, regulatory and internal audit. Sharing of best practices allows for more effective and efficient operations at the local operating subsidiary level than if the subsidiary was operating stand-alone from the Fortis group. The collaboration also provides for certain cost efficiencies, such as through joint procurement activities. FI's operating subsidiaries, including FEI, FBC, and ACGS would not have the benefit of this strategic oversight and sharing of best practices if they were not under the umbrella of FI.

5.3.2.3 Benefits from FI Administered Company-wide Group Insurance Program

FortisBC's customers benefit from lower insurance premiums due to economies of scale obtained with the consolidated Fortis group of companies as compared to if FEI and FBC were required to seek out their insurance premiums on a stand-alone basis. The actual insurance premiums are charged directly to FHI, FEI, FBC, ACGS and other FHI subsidiaries based on replacement value for property insurance and revenue for liability policies. However, the FI corporate services include FI's cost to manage and administer the insurance program. The FI risk management department is responsible for group property and casualty insurance policies renewal processes, determining and developing risk transfer strategies, determining policy limits and optimal retention levels, handling and administration of FI group first party property damage claims and third party claims and overseeing risk and loss control inspections including the management of recommendations and subsequent response.

5.4 *FI CORPORATE SERVICES ALLOCATION METHODOLOGY*

The costs of the FI corporate services, as described in Section D5.3, are allocated to FHI, FEI, ACGS and FBC (together defined as the "FortisBC Subsidiaries") on a percentage basis. The allocation is calculated using the following factors:

1. Controllable operating costs for the FortisBC Subsidiaries as a percent of all Fortis group operating costs; and
2. Total assets (excluding goodwill) for the FortisBC Subsidiaries as a percent of all Fortis group total assets.

The use of more than one factor for the cost allocation reflects a balanced methodology, and is consistent with the approach used by other utility holding companies and their subsidiaries. Using more than one factor recognizes that there is not one perfect allocator, and mitigates the inherent risk associated using one measure for calculating general cost allocations.

The two cost allocation factors are weighted as follows: (i) 75 percent to total assets (excluding goodwill), and (ii) 25 percent to total controllable operating expenses. The 75 percent weighting 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 lower 25 percent weighting for controllable operating expenses recognizes that FI's subsidiaries operate in a substantially autonomous manner, and directly manage most costs.

The FI allocator formula is as follows:

(FortisBC Subsidiaries' portion of Total FI Assets (Excluding Goodwill) x 75%)
+
(FortisBC subsidiaries' portion of Total FI Controllable Cost Allocation x 25%)
=
Overall Allocation to FortisBC Subsidiaries (FHI, FEI, ACGS, FBC)

After applying the above allocator formula, the percentage allocation of FI corporate services to FortisBC Subsidiaries is as follows:

Table D5-1: FI Corporate Services 2018 Allocation to FortisBC Subsidiaries

Allocation Factor	Weighting	FortisBC Subsidiaries' 2018 Allocation
Asset Allocation (Excluding Goodwill)	75%	21.9%
Controllable Cost Allocation	25%	19.9%
Overall Allocation		**21.4%**

The application of the above overall allocation of 21.4 percent, plus 66.9 percent of the Executive Vice President (EVP) Western Utility Operations, results in the 2018 allocations of business activities performed by FI to support the FortisBC Subsidiaries shown in Table D5-3.

The EVP, Western Utility Operations is providing oversight to the FortisBC Subsidiaries and FortisAlberta. Therefore, the salary of the EVP is shared amongst the two entities and 66.9 percent represents the portion allocated to the FortisBC Subsidiaries based on 75 percent total assets excluding goodwill and 25 percent controllable operating costs.

Table D5-2: Projected 2018 FI Eligible Corporate Service Costs Allocated to FortisBC Subsidiaries

FI Recoverable Cost Categories	% Allocated to FortisBC Subsidiaries	FortisBC Subsidiaries Portion of FI Costs 2018 ($)
Salaries (Excl EVPs, Western & Eastern Utility Ops)	21.40%	$ 3,993,593
Salary (EVP, Western Utility Operations)	66.90%	388,923
Directors' fees and costs	21.40%	726,480
Trustees and DRIP administration	21.40%	128,109
Consulting	21.40%	485,009
Legal	21.40%	703,729
Audit	21.40%	291,306
Listing and filing	21.40%	312,094
Annual meeting and report	21.40%	206,915
Other fees	21.40%	91,373
Insurance	21.40%	223,172
Office related	21.40%	666,432
Investor Relations	21.40%	151,225
Communications	21.40%	61,262
Miscellaneous	21.40%	10,689
Travel	21.40%	291,452
Telephone	21.40%	39,668
Recoverable Amount		$ 8,771,431

As shown in the table above, had the described allocation methodology for FI corporate services been used in 2018, $8.771 million would be charged from FI to FHI to support the FortisBC subsidiaries. For the purposes of the 2018 CS Study, this $8.771 million is pooled with the FHI corporate service costs, described in Section D5.5, and then charged out to FEI, FBC and ACGS based on the FHI allocation methodology described in Appendix D5, Section 5.1.

FortisBC notes that the actual charges each year will be updated based on FI eligible corporate service costs and a recalculation of the allocation factors using the same methods described above.

5.5 DESCRIPTION OF FHI CORPORATE SERVICES

In addition to the FI corporate services described above, FHI, the parent company of FEI and ACGS, provides key corporate functions directly to FEI, FBC and certain of FHI's other subsidiaries including ACGS. The FHI corporate services provided to FEI, FBC and ACGS are incremental to the corporate services provided by FI. The FHI corporate services are described by department as follows:

- Treasury and Financial Planning – FHI is responsible for: the execution of short-term and long-term financings; cash management and forecasting; the arrangement of operating credit facilities; and, the negotiation of bank-service fees for all FortisBC companies. FHI is also responsible for: treasury related controls and compliance; compliance reporting; hedging of interest rate and foreign exchange risks; providing information in support of credit ratings; maintaining bank and debt investor relationships; assisting in the preparation of regulatory submissions in support of ROE, capital structure and financing related matters; and, preparing quarterly forecasts of consolidated earnings.
- External Financial Reporting – FHI is responsible for: the preparation of monthly, quarterly and annual financial statements for FHI, FEI, FBC and other FHI subsidiaries; coordination with external auditors; analysis of financial information; assisting in the preparation of the Annual Information Form, quarterly and annual Management Discussion and Analysis and other continuous disclosure documents; coordinating consistent accounting policy treatment across the FortisBC group of companies; preparing for and implementing US GAAP changes; and, maintaining internal controls over financial reporting.
- Taxation – FHI 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 filings and annual reports), tax planning including guidance and support for significant transactions, and tax dispute management and resolution.
- Internal Audit – FHI is responsible for planning and conducting audits and operational reviews of all areas of the gas and electric utilities, as well as facilitation of the annual enterprise risk management assessment process. This department monitors and evaluates the effectiveness and efficiency of internal controls and risk management strategies primarily for FEI, FBC and ACGS. Internal Audit's responsibility has expanded over the past several years to include both assurance and advisory services to support operational areas, enhancing information system controls and data analysis and ensuring ongoing compliance with regulatory requirements.
- Risk Management and Insurance – FHI is responsible for managing the insurance program on a day-to-day basis. The insurance and risk management department is

responsible for the renewal of all third party insurance and the cost of the premiums paid for those policies.

- Legal – FHI provides legal services and counsel 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.
- Facilities and IT – FHI provides building space, computer software, computer hardware, office supplies and stationery, and administration and computer outsourcing.
- Board of Directors – FHI ensures all continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, manages the relationship and corporate activities of the FEI and FBC Joint Board of Directors, and develops and maintains governance procedures and policies

In addition to these corporate services specifically provided by FHI, the FI corporate service costs, as described in Table D5-2, are also included in the pool of eligible FHI corporate service costs. The pool of eligible FHI corporate service costs allocated to FEI, FBC and ACGS excludes certain costs that are specific to FHI or its other subsidiaries, including the following:

- Corporate development costs;
- Legal fees incurred for non-regulated entities; and
- Ineligible components of the Fortis Inc. management fee related to pension bonus amounts for defined benefit supplemental pension plans and stock compensation costs.

The nature of FHI corporate service costs, after the previously mentioned exclusions, are generally consistent with those that existed in FHI during FEI's 2012-13 Revenue Requirement and the Current PBR terms. The methodology of how these costs are allocated to FEI and FBC is discussed in the next section.

5.6 FHI CORPORATE SERVICES ALLOCATION METHODOLOGY

The eligible pool of the FHI corporate service costs are allocated to FEI, FBC and ACGS using what is commonly known as the Massachusetts Formula, which consists of a hybrid of an activity based costing method and a financial composite cost allocator. The Massachusetts Formula is a widely used and accepted method for allocating costs in the utility industry in North America. The Massachusetts Formula is generally used when there is substantial sharing of costs amongst entities. It is calculated as an average of (i) Gross margin (revenue less cost of gas or energy), (ii) Payroll, and (iii) Average NBV of tangible capital assets plus inventories. The forecasted amounts for each of the three components are estimated for all applicable entities and given equal weight. An average is then computed for each operating entity, which when compared to the total, calculates a ratio used to allocate its share of the cost pool.

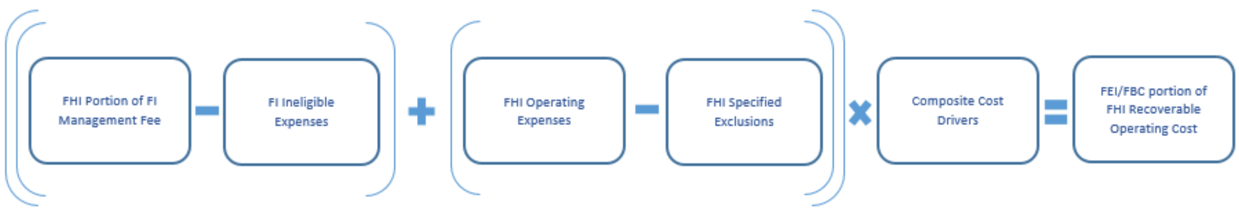
FEI and FBC have applied the Massachusetts Formula to allocate common costs in previously approved RRAs. Some examples are:

- Corporate service costs have been allocated from FHI to the pre-amalgamated FEI, FEVI and FEW utilities using the Massachusetts Formula for many years;
- Board of Directors costs have been allocated from FHI to FEI and FBC utilizing the Massachusetts Formula since 2012 as approved by Order G-110-12; and
- FortisBC executive costs were approved to be allocated between FEI and FBC using the Massachusetts Formula beginning in 2012 pursuant to Orders G-138-14 and G-139-14 for FEI and FBC, respectively.

Applying this same cost allocation methodology to corporate service costs charged to FEI, FBC and ACGS beginning in 2020 allows for a consistent and familiar methodology which has previously been reviewed and tested in regulatory proceedings.

The following figure depicts the Massachusetts Formula allocator methodology.

Figure D5-2: Application of Massachusetts Formula to allocate FHI Corporate Service Costs



After applying the Massachusetts formula, the allocation percentage of FHI corporate services to be applied to FEI, FBC and ACGS are 73 percent, 22 percent and 5 percent, respectively. If this method was in place for 2018, allocations of business activities performed by FI and FHI to support FEI and FBC would be as shown in Table D5-3.

Table D5-3: 2018 FHI Corporate Services Costs Allocation

FHI Recoverable Cost Categories	FEI Portion (73%) of 2018 FHI Costs ($)	FBC Portion (22%) of 2018 FHI Costs ($)
Treasury and Financial Planning	$ 585,497	$ 180,663
External Financial Reporting	346,535	106,928
Taxation	656,846	202,679
Internal Audit	1,007,754	310,956
Risk Management and Insurance	176,428	54,439
Legal	1,313,639	405,342
Facilities and IT	807,801	249,258
Board of Directors	896,427	276,606
FI Management Fee	5,227,742	1,613,092
Recoverable Amount	**$ 11,018,669**	**$ 3,399,962**

The above table calculates an FHI management fee of approximately $11.0 million and $3.4 million for FEI and FBC, respectively, if this proposed cost-sharing model had been in place for 2018. However, the use of 2018 figures was for the purposes of the 2018 CS Study only, which determines the methodology to allocate corporate service costs to the Utilities starting in 2020. During 2018 and 2019, the FI and FHI corporate services are being direct charged to FBC, and FBC was not included in the sharing of FHI corporate services.

The following table D5-4 summarizes the year over year impact of bringing FBC into a cost-sharing model with FEI and ACGS effective 2020, as compared to having FI and FHI continue to direct charge FBC for corporate services.

Table D5-4: FHI Corporate Services Costs Allocated to FEI and FBC

Projected FI and FHI Corporate Services Allocated to regulated utilities	FEI	FBC
	($000s)	
2019 FHI Management Fee	12,030	
2019 FHI services direct charged to FBC		1,197
2019 FI services direct charged to FBC		1,544
Total 2019 Corporate services charged	**12,030**	**2,741**
2020 FHI Management Fee (1)	11,908	3,439
less: FBC costs now included in FHI corporate services (2)		(315)
Total 2020 Corporate services charged	**11,908**	**3,124**
Variance ($)	(122)	383

Notes:

(1) The 2020 FHI management fees have been estimated based on the same methodology included and reviewed in the 2018 CS Study. Therefore, the $11.019 million and $3.400 million allocated to FEI and FBC for 2018 corporate services shown in table Table D5-3 have been projected forward.

(2) With the implementation of a cost sharing model for 2020, there are certain O&M costs that historically reside in FBC which are now required to be included in the FHI corporate services pool of costs to ensure appropriate sharing. This reallocated O&M amounts to approximately $315 thousand and relates primarily to Internal Audit contractor services, as well as certain facility and IT costs which are now included in the eligible pool of FHI corporate services.

By including FBC in the FI and FHI corporate cost allocation methodology beginning in 2020, FortisBC estimates that there will be a small decrease in the total corporate services charged to FEI compared to 2019. Similarly, there is expected to be a small increase in cost of service for FBC, as compared to 2019 using the previous methodology of direct charging. As a result of including FBC in a corporate services sharing model, there is expected to be no measurable impact on FEI's delivery rates for 2020 and a forecast increase of approximately 0.1 percent for FBC's customer rates in 2020.

While FortisBC has provided estimates of 2019 and 2020 corporate service costs under the old and new methodologies, the actual costs and the formula indicators will be known in the years when the services are provided. With this Application, FortisBC is requesting approval to apply the Massachusetts Formula to allocate the FI and FHI corporate services to FEI and FBC beginning in 2020.

5.7 *CONCLUSION*

The allocation of FI and FHI corporate service costs, including the addition of FBC to sharing methodology, has been reviewed by KPMG in the 2018 CS Study. In Section 7.4 of the 2018 CS Study[217], KPMG states:

> 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.

FortisBC is requesting approval to apply the methodology of aggregating its common corporate service costs from FI and FHI and allocating them to FEI and FBC using the Massachusetts formula as described above and in more detail in the 2018 CS Study.

217 Appendix D5.

6. CAPITALIZED OVERHEAD STUDY

6.1 *INTRODUCTION*

FEI and FBC are proposing to apply capitalized overhead rates of 16 percent and 15 percent, respectively, of gross O&M to regular capital expenditures for the term of the Proposed MRPs. The capitalized overhead rates reflect a reasonable basis for capitalization of costs related to the increased capital activities, for both FEI and FBC, that have not been directly charged to capital projects. The allocation of capitalized overhead costs is consistent with the methodology from prior years' studies and filings, and corroborated with established rate-regulated utility practice, the BC's Uniform System of Accounts (USofA) and US GAAP.

In the sections below, FortisBC discusses the basis for allocating overhead costs to capital projects, FortisBC's methodology for capitalized overhead studies, and the results of the most recent capitalized overhead studies for FEI and FBC.

6.2 *OVERHEAD COSTS ALLOCATED TO CAPITAL PROJECTS*

Utilities operate in a very capital intensive industry where an ongoing capital program is required to sustain the current system and to meet customer demand. Utilities' capital expenditures can include the physical construction or purchase of property, plant and equipment. In order to construct and bring an item of property, plant and equipment into service, multiple business activities of the utility are involved.

Certain activities incurred during construction or acquisition of a capital asset are considered direct costs which meet the definition of costs to be capitalized under US GAAP as they are associated with the acquisition, development and construction of an asset to the condition necessary for it to be capable of operating for its intended use. Examples of direct costs may include labour, transportation, engineering services, procurement, consulting, travel costs, employee benefits and certain overhead costs. Directly attributable activities can be charged directly to the capital project, or may be charged to capital projects from O&M indirectly through a capitalization methodology. For several directly attributable activities that support the construction of multiple capital projects, the use of a capitalized overhead allocation is a more efficient process to allocate direct costs rather than direct charging each individual activity to each specific project.

Other activities that are not directly attributable to a specific project, such as certain activities performed by human resources, finance, legal and regulatory, may also be capitalized. These activities are integral in constructing and supporting a utility's capital program, and therefore allocating these indirect overhead costs to capital projects for regulated utilities is an accepted practice embedded in US GAAP. Accounting Standards Codification 980, Regulated Operations (ASC 980) explicitly acknowledges the capitalization of indirect costs as approved by a regulator.

In addition to generally accepted accounting principles, the capitalization of overhead costs is embedded in BC's USofA. Both the BCUC Gas USofA, initially established in the 1960s, and the BCUC Electric USofA, initially established in the 1980s, include "Cost of overhead charged to construction" as a cost item to be included in section 6, "plant acquired or constructed", as defined below:

> 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.

While the Federal Energy Regulatory Commission (FERC) does not have jurisdiction within Canada, its accounting guidelines can be referenced for establishing regulated utility industry practice of costs incurred to support capital expenditures. FERC's USofA "Electric Plant Instruction, Number 4, Overhead Construction Costs" is clear that capital expenditures should contain all costs, direct charged and indirectly allocated, related to construction activity.

While no single guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive standard, all of the above support that both direct and indirect overhead costs are appropriately allocated to capital projects for rate-regulated utilities.

6.3 *METHODOLOGY FOR FORTISBC CAPITALIZED OVERHEAD STUDIES AND APPLICATION OF CAPITALIZED OVERHEAD RATES*

FortisBC assesses the activities of its various business areas in support of its capital expenditure program. Depending on the level of capital work, these activities may be increasing, decreasing or remaining constant. While certain jurisdictions do not require regular filing and approval of the allocations for capitalized overhead costs, FortisBC has a practice of periodically filing updated capitalized overhead studies and requesting regulatory approval of the methodology to ensure that its capital expenditures include the appropriate level of capitalized overhead costs. For this Application, FortisBC engaged KPMG to review its capitalized overhead methodology and prepare a capitalized overhead study for each of FBC and FEI (referred to as the 2018 Capitalized Overhead Studies).

FortisBC's O&M includes the costs for activities that are primarily for operating the business independent of the levels of capital. However, there exists a portion of O&M that is required to initiate and enable capital expenditures, which is then allocated to capital expenditures as overheads capitalized. For FortisBC, capitalized overhead is calculated by applying the overhead capitalization rate to gross operations & maintenance, after O&M has been reduced by direct charges to capital and other non-O&M accounts. While the capitalized overhead rate is determined on a broader basis, the resulting capitalized overhead amount is charged on a more detailed pro rata basis (based on capital additions in the period) to the appropriate asset accounts for each individual capital project.

The capitalized overhead rates determined in the 2018 Capitalized Overhead Studies are assigned to regular capital, which excludes CPCNs and certain other major capital projects. While there is a portion of net O&M that remains, after allocating the overheads capitalized, that is indirectly supporting CPCNs and major capital projects, FortisBC has not assigned capitalized overhead to these capital projects. The rationale is that incremental costs and activities for these types of projects, including external contractor costs, have been charged directly to CPCNs and major projects and therefore do not require a mechanism such as a capitalized overhead rate to allocate costs from O&M to the capital projects. Consistent with historical and current practice, the actual amount of overheads capitalized will be recorded at the forecast amount so that there will be no variances in either the capital additions or O&M related to the amount of capitalized overhead in any given year.

The 2018 Capitalized Overhead Studies use a similar survey based approach as was undertaken in the capitalized overhead studies prepared in 2013 and approved in Orders G-138-14 and G-139-14. As in 2013, FortisBC engaged independent international accounting and advisory firm, KPMG, to perform a review of its capitalized overhead methodology for the Proposed MRP terms. In the 2018 FEI Capitalized Overhead Study and the 2018 FBC Capitalized Overhead Study included in Appendix D6-1 and D6-2 to this Application, KPMG states that the *"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."*

6.4 RESULTS OF CAPITALIZED OVERHEAD STUDY FOR FEI

For the term of the Proposed MRP, FEI proposes a capitalized overhead rate of 16 percent of gross O&M as compared to the current 12 percent rate approved by Order G-138-14. This increase is primarily due to the increase in growth and sustainment capital activities that FEI has experienced over the term of the Current PBR Plan and that is expected to continue over the Proposed MRP term. As described in Section C3.3, forecast regular capital expenditures from 2020 through 2024 are higher than the level of regular capital expenditures approved during the Current PBR term. These approved capital expenditures were determined from the 2013 approved regular capital, which was the basis for the determination of the current capitalized overhead rate of 12 percent. This increase in capital activity involves work done not only by employees that direct charge to capital projects, but also through the support and activities of various departments whose costs reside in O&M.

While the Operations area continues to be a major driver of the capitalized overhead allocation, there is a greater requirement from various other business areas, such as engineering, external relations, procurement, information systems, regulatory, legal, human resources and finance, to enable the capital expenditures.

The input from the business areas through the survey-based approach has led to the determination of a capitalized overhead rate of 16 percent to be applied over the Proposed MRP term.

When recommending the 16 percent capitalized overhead rate, consideration was given to the current and forecast level of regular capital expenditures as explained above. In addition, a reasonableness assessment was performed to compare against prior levels of capital expenditures, approved capitalized overhead rates, and the net O&M over the past ten years, as shown in the table below.

Table D6-1: FEI Capital, O&M and Capitalized Overhead 2009-2020 ($000s)

	Order G-33-07	Order G-140-09/ G-141-09		Order G-44-12		Orders G-138-14 & G-65-14	Order G-86-15 & G-106-15	Order G-193-15	Order G-182-16	Order G-196-17	Order G-237-18 & G-10-19	
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Projected
Capex (excl. OH)	113,031	121,930	129,857	157,920	156,089	164,250	156,440	162,748	160,711	170,406	189,281	228,133
Gross O&M	206,502	237,695	247,382	263,087	272,187	264,869	270,475	271,620	269,275	275,631	281,148	291,761
Capitalized OH	(33,040)	(33,277)	(34,622)	(36,832)	(38,106)	(32,501)	(32,457)	(32,594)	(32,313)	(33,076)	(33,738)	(48,252)
Net O&M	173,462	204,418	212,760	226,255	234,081	232,368	238,018	239,026	236,962	242,555	247,410	243,509
Capitalized OH Rate	16%	14%	14%	14%	14%	12%	12%	12%	12%	12%	12%	17%
Capitalization Rate	29%	27%	27%	23%	24%	20%	21%	20%	20%	19%	18%	21%

As shown in Table D6-1 above, a 16 percent capitalized overhead rate for 2020 results in a level of net O&M (gross O&M less capitalized overhead) that is within a reasonable range as compared to prior years, taking into account inflationary pressures. The proportion of capitalized overhead to the annual capital expenditures is presented as the capitalization rate. A relatively consistent capitalization rate in 2020 as compared to the rate over the term of the Current PBR Plan is another indication that FEI's proposed capitalized overhead rate of 16 percent is within a reasonable range.

The 16 percent capitalized overhead rate is expected when compared to the current overhead rate of 12 percent, which was established back in 2013, due in part to the level of FEI's capital activity gradually increasing over the last six years partly due to an increase in customer attachments. The recommended 16 percent capitalized overhead rate is comparable to the 14 percent capitalized overhead rate approved in both the 2010-2011 FEI (then Terasen Gas Inc.) Negotiated Settlement Agreement (Order G-141-09) and the 2012-2013 FEI Revenue Requirements Application (G-44-12), and is consistent with the 16 percent capitalized overhead rate approved for years 2004 through 2007 as part of FEI's Multi-Year Performance-Based Rate Plan, and extended to 2008 and 2009 as part of a Settlement Agreement (Order G-33-07).

The capitalized overhead rate was developed by KPMG, and reviewed and corroborated by management. KPMG's 2018 Capitalized Overhead Study for FEI is found in Appendix D6-1 and includes the following relevant conclusions:

> 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

> 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, the estimated overhead capitalization rate is approximately 16 percent.

FEI estimates that the impact on delivery rates of a change to the capitalized overhead rate is approximately 0.1 percent for every 1.0 percent change in the capitalized overhead rate. Therefore, all else equal, increasing the capitalized overhead rate from 12 percent to 16 percent decreases customer delivery rates by approximately 0.4 percent in the year of implementation.

6.5 *RESULTS OF CAPITALIZED OVERHEAD STUDY FOR FBC*

For the term of the Proposed MRP, FBC proposes to maintain the capitalized overhead rate of 15 percent of gross O&M. The existing capitalized overhead rate of 15 percent was established by Order G-139-14.

While there has been an increase in customer growth and sustainment capital activities at FBC over the term of the Current PBR Plan, it has not grown at a significant enough pace to warrant an increase in the capitalized overhead rate. As described in Section C3.4, the forecast level of capital expenditures from 2020 through 2024 is higher than the capital incurred during the Current PBR term. This increase is a result of a number of non-routine capital projects that are expected to rely on external contractors to construct the capital assets and include a greater degree of direct charging of costs. Regular capital activity is undertaken not only by those that direct charge to capital, but also through the support and activities of various departments whose costs reside in O&M, such as engineering, external relations, information systems, regulatory, legal, human resources and finance.

The input from the business areas through the survey-based approach, consistent with previously filed and approved capitalized overhead studies, has led to the determination of a capitalized overhead rate of 15 percent to be applied over the Proposed MRP term.

When recommending the 15 percent capitalized overhead rate, consideration was given to the current and forecast level of regular capital expenditures, and a reasonableness assessment was also performed to compare to prior levels of capital expenditures, approved capitalized overhead rates and the net O&M over the past six years.

Table D6-2: FBC Capital, O&M and Capitalized Overhead 2014-2020 ($000s)

	Order G-139-14	Order G-107-15	Order G-202-15	Order G-8-17	Order G-38-18 & G-131-18	Order G-246-18	
	2014	2015	2016	2017	2018	2019	2020 *
	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Approved forecast	Projected
Capex (excl. OH)	48,589	46,636	46,548	48,551	47,763	52,633	93,524
Gross O&M	60,710	59,091	56,979	57,549	58,591	59,201	64,328
Capitalized OH	(9,106)	(8,864)	(8,547)	(8,632)	(8,789)	(8,880)	(9,649)
Net O&M	51,604	50,227	48,432	48,917	49,802	50,321	54,679
Capitalized OH Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Capitalization Rate	19%	19%	18%	18%	18%	17%	10%

* 2020 projected capital expenditures include non-recurring regular capital expenditures, which were not included in the 2014-2019 PBR period forecasts.

As shown in table D6-2 above, the trend of FBC's net O&M and regular capital expenditures, excluding major projects and CPCNs, from 2014 through to 2020 has remained relatively constant, taking into consideration inflationary pressures, thus supporting a consistent capitalized overhead rate of 15 percent. When FBC was going through a significant customer growth and refurbishment phase from 2007 through to 2013, similar to what FEI is currently experiencing, the approved capitalized overhead rate was higher at 20 percent. The proportion of capitalized overhead to the annual capital expenditures is presented as the capitalization rate. The projected 2020 O&M capitalization rate is lower than the rate in the 2014 to 2019 period, primarily because certain capital projects forecast in 2020 are expected to be constructed using a higher proportion of external resources.

The capitalized overhead rate of 15 percent was developed by KPMG, and reviewed and corroborated by management. KPMG's 2018 Capitalized Overhead Study for FBC is found in Appendix D6-2 and includes the following relevant conclusions:

> 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.
>
> 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.
>
> KPMG finds the FBC direct overhead loading process and Survey-based model and the underlying costs to be consistent with the cost allocation methodologies and evaluation criteria as proposed by FBC and guidance related to U.S. GAAP.
>
> Based on the results of the Survey Model, the estimated overhead capitalization rate is approximately 15 percent. Based on the results of the direct overhead loading model, the estimated direct overhead loading pool is $5.0 million.

Given that FBC is not recommending a change in the capitalized overhead rate of 15 percent, there is no impact of FBC's proposal on customer rates.

6.6 *CONCLUSION*

Based on the conclusions of the Capitalized Overhead Studies conducted by KPMG, FEI and FBC are proposing to apply capitalized overhead rates of 16 percent and 15 percent, respectively, of gross O&M to regular capital expenditures for the term of the Proposed MRPs.