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June 17, 2019

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
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Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

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

Project No. 1598996

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On March 11, 2019, FortisBC filed the Application referenced above. In accordance with BCUC Order G-64-19 setting out the Regulatory Timetable for the review of the Application, FortisBC respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.
FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties

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A. EVOLVING OPERATING ENVIRONMENT

1.0 Reference: EVOLVING OPERATING ENVIRONMENT

Exhibit B-1 (Application), Section B1.1, pp. B-1 – B-3

Key Influences in FortisBC's Operating Environment

On pages B-1 to B-3 of the Application for Approval of a Multi-Year Rate Plan (MRP) for 2020 through 2024 (Application), FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC) provides an overview of the five "key influences in FortisBC's operating environment," described as follows:

- Policy direction and mandate from all levels of government towards decarbonization;
- Rising 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 changes;
- 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.

On pages B-3 and B-4 of the Application, FortisBC summarizes the "key regulatory measures" underpinning the Pan-Canadian Framework.

1.1 Please provide a detailed explanation in tabular format of how each of the five "key influences" described on pages B-1 through B-3 of the Application specifically impacts FEI and specifically impacts FBC, including the following:

- The opportunities each influence presents and how FEI and FBC plan to respond. Please make specific references to the aspects of the proposed MRP which are intended to address these opportunities;
- The challenges each influence presents and how FEI and FBC plan to respond. Please make specific references to the aspects of the proposed MRP which are intended to address these challenges;
- A qualitative and quantitative explanation of the impact on operating and maintenance (O&M) expenses during the proposed MRP term and how this impact has been addressed in the MRP. Please tie this explanation

into the specific areas of O&M spending discussed in the Application, where applicable;

- A qualitative and quantitative explanation of the impact on capital expenditures during the proposed MRP term and how this impact has been addressed in the MRP. Please tie this explanation into the specific areas of capital spending discussed in the Application, where applicable; and
- The expected impact of each of the influences, if any, on FEI and FBC's load/revenues during the proposed MRP term.

Response:

The tables below provide the requested explanation of each of the five key influences described on pages B-1 through B-3 of the Application. Please note that in an effort to be responsive to the information request and helpful to the reader, the tables below provide the highlights of the Application in relation to the requested information. For further detail, please refer to the Application.

	Influence 1: Policy direction and mandate from all levels of government towards decarbonization.
Opportunities	Policy direction at all levels of government is creating increased demand for clean energy for buildings, transportation and industry in an effort to reduce emissions across all sectors. This creates opportunities for FortisBC, including the following examples: • The CleanBC includes a target of 15% renewable gas content by 2030 which provides support for increasing clean energy delivery through the natural gas distribution system; • The provincial Renewable and Low Carbon Fuel Requirement Regulation is expected to be updated to include a 20% reduction in carbon intensity by 2030 which will positively impact demand for natural gas for transportation; • The CleanBC includes a Zero Emissions Vehicle mandate for passenger vehicles to be fully implemented by 2040 which provides increased demand for electricity and electric vehicle charging infrastructure; and • The CleanBC seeks to expand the electrification of buildings by providing incentives for electric heat pumps, which positively impacts electricity demand.

	Influence 1: Policy direction and mandate from all levels of government towards decarbonization.
Challenges	Policy direction also includes significant challenges for FortisBC, particularly in the case of natural gas. Examples of policy challenges facing FortisBC include: • A Federal Clean Fuel Standard aimed at reducing the carbon intensity of liquid, gaseous, and solid fuels consumed in buildings, transportation, and industry which is expected to place downwards pressure on natural gas demand and/or upwards pressure on costs; • The CleanBC seeks to expand the electrification of buildings by providing incentives for electric heat pumps, which negatively impacts natural gas demand; • Municipal adoption of increasingly stringent levels of the BC Energy Step Code which places downwards pressure on natural gas demand; • Municipal climate emergency declarations and the growing adoption of 100 percent renewable energy mandates by 2050 which place downwards pressure on the use of natural gas; and • The City of Vancouver's Big Move #4 which seeks to have all new and replacement heating and hot water systems in buildings produce zero emissions by 2025.
Response to Challenges and Opportunities within the MRPs	FortisBC has proposed the following as part of its MRPs in an effort to address these opportunities and challenges: • A five year rate plan which allows an increased utility focus on managing the business with a long-term view and increased operational flexibility to address the pace and growing scope of industry transformation; • Stable levels of O&M funding sufficient to address emerging pressures and an ability to efficiently allocate resources to address challenges and opportunities; • Flexibility to innovate and adapt through a Clean Growth Innovation Fund that aims to accelerate the pace of clean energy innovation, achieve performance breakthroughs and cost reductions, and provide customers with cost effective, safe and reliable energy solutions; and • Incentive to invest in the future of the utilities though targeted incentives that are aimed at achieving outcomes that align with policy direction and support the transition to a lower carbon economy.

	Influence 1: Policy direction and mandate from all levels of government towards decarbonization.
Impact on O&M	Policy direction at all levels is consistent and signals that addressing emissions is a key public interest; however, government policy at all levels continues to evolve and develop. Because of this uncertainty, FortisBC is unable to provide a forecast of O&M or capital expenses related to addressing policy impacts. However, in the near term, FortisBC has included incremental O&M funding for: FEI • Customer Expectations - $1.360 million focussed on customer growth and retention through “Connect to Gas” and in-house resources to meet evolving customer communication needs. • Engagement - $3.360 million focussed on raising awareness of traditional and innovative energy solutions, supporting the Climate Action Partners program that assists governments, Indigenous communities and other organizations with climate plans that consider FortisBC’s energy solutions, increased support in digital public engagement channels, and increased participation in early stage policy development. FBC • Engagement - $0.080 million focussed on increased support in digital public engagement channels. In addition, both FEI and FBC will forecast O&M related to Investments in a Clean Growth Future (see Section C4.4.2 of the Application) annually as part of the Annual Review of Rates. Climate-related policies will place upward pressure on O&M spending in order to meet growing compliance requirements and continue to evolve FortisBC’s energy solutions and services in the transition to a lower carbon economy.
Impact on Capital	As noted above, FortisBC is unable to provide a forecast of capital expenses related specifically to addressing policy impacts as many policies continue to evolve and develop. However, both FEI and FBC will forecast capital related to Investments in a Clean Growth Future (see Section C4.4.2 of the Application) annually as part of the Annual Review of Rates. Qualitatively, climate-related policies create new requirements for capital expenditures to comply with increasingly stringent emissions requirements and to meet customers’ changing energy needs.

	Influence 1: Policy direction and mandate from all levels of government towards decarbonization.
Impact on Load / Revenues	FortisBC's most recent long-term resource plans provide a 20-year vision including consideration of environmental policy: • FEI's 2017 LTGRP includes Appendix E, which indicates downward pressure on natural gas demand in the absence of FEI's sizeable contribution toward carbon reduction opportunities. • FBC's 2016 LTERP considered environmental policy including two key load drivers that have the most impact on FBC: electric vehicle adoption and distributed generation via rooftop photovoltaics. EV adoption is expected to increase demand while distributed generation will have the opposite effect. However, generally speaking, policies aimed at electrification will serve to increase demand for electricity.

1

	Influence 2: Rising customer expectations with respect to service, engagement channels and keeping pace with other service providers.
Opportunities and Challenges	FortisBC has identified that changing customer expectations represent both an opportunity and a challenge. While customers continue to expect high quality, safe and reliable service, service expectations are changing due to improved customer access to technology and experiences with other providers, and with respect to FortisBC's stewardship, leadership and accountability in relation to environmental issues. As a result, FortisBC must continue to adapt to changing customer expectations in order to continue meeting their needs. Changing customer energy needs also provide new opportunities to serve customers (e.g., the emergence of demand for clean transportation).
Response to Challenges and Opportunities within the MRPs	FortisBC has proposed the following as part of its MRPs in an effort to address these opportunities and challenges: • Stable levels of O&M funding sufficient to address emerging pressures and an ability to efficiently allocate resources to address challenges and opportunities. • Inclusion of a combination of benchmark and informational service quality indicators focused on customer needs. • The inclusion of targeted incentives focussed on customer engagement via enhancing convenient access to information and services through digital communication channels as well as on addressing customer emissions goals through renewable gas, clean transportation and emission reductions. • Flexibility to innovate and adapt through a Clean Growth Innovation Fund that aims to accelerate the pace of clean energy innovation, achieve performance breakthroughs and cost reductions, and provide customers with cost effective, safe and reliable energy solutions.

	Influence 2: Rising customer expectations with respect to service, engagement channels and keeping pace with other service providers.
Impact on O&M	FortisBC has included incremental O&M required to address this influence as follows: FEI • Customer Expectations - $1.360 million focussed on customer growth and retention through "Connect to Gas" and in-house resources to meet evolving customer communication needs. • Engagement - $3.360 million focussed on raising awareness of traditional and innovative energy solutions, supporting the Climate Action Partners program, which assists governments, Indigenous communities and other organizations with climate plans that considered FortisBC's energy solutions, increased support in digital public engagement channels, and increased participation in early stage policy development. FBC • Engagement - $0.080 million focussed on increased support in digital public engagement channels. Qualitatively, increasing customer expectations with respect to service places upwards pressure on O&M spending.
Impact on Capital	FortisBC's capital requirements include enhancements to customer service-related systems. FortisBC has commenced a bill redesign project focusing on increasing customer engagement, the Company is also designing an online customer portal that will give customers access to various energy usage reports as well as creating a single sign on solution for customers. In addition, the Company has commenced a review of its customer information system(s). Qualitatively, increasing customer engagement requirements increases the need for capital related to supporting the needs of customers as well as enhancing communication with customers.
Impact on Load / Revenues	Generally speaking, meeting customer expectations with respect to service, engagement channels and keeping pace with other service providers is expected to support increased customer engagement and may translate to increased demand for FortisBC's energy solutions and services.

1

	Influence 3: Increased need for engagement with stakeholders and Indigenous communities as a result of stakeholder activism and provincial and federal policy changes.
Opportunities	With lower than desired levels of public awareness and involvement in energy decisions, there is an opportunity for FortisBC to provide leadership and education on how natural gas and electric distribution systems can play an active role in shifting BC to a lower carbon economy. FortisBC has a strong record of building effective relationships, including with Indigenous communities, necessary to support increased engagement.

	Influence 3: Increased need for engagement with stakeholders and Indigenous communities as a result of stakeholder activism and provincial and federal policy changes.
Challenges	Consultation and engagement requirements are increasing in their depth and complexity. This includes increasing expectations from stakeholders and regulators for enhanced engagement and consultation. These requirements will continue to change and evolve over time including the federal and provincial implementation of the United Nations Declaration on the Rights of Indigenous Peoples and the potential introduction of new Environmental Assessment legislation driving the need for greater engagement and consultation.
Response to Challenges and Opportunities within the MRPs	FortisBC has proposed the following as part of its MRPs in an effort to address these opportunities and challenges: • A five year rate plan which allows an increased utility focus on managing the business with a long-term view and increased operational flexibility to address the pace and growing scope of industry transformation; and • Stable levels of O&M funding sufficient to address emerging pressures and an ability to efficiently allocate resources to address challenges and opportunities.
Impact on O&M	FortisBC has included incremental O&M required to address this influence as follows: FEI • Engagement - $3.360 million focussed on raising awareness of traditional and innovative energy solutions, supporting the Climate Action Partners program which assists governments, Indigenous communities and other organizations with climate plans that considered FortisBC's energy solutions, increased support in digital public engagement channels, and increased participation in early stage policy development. • Indigenous Relations - $0.888 million focused on renewing and strengthening Indigenous relations, particularly with respect to access to land. FBC • Engagement - $0.080 million focussed on increased support in digital public engagement channels. Qualitatively, the increasing requirement for engagement of stakeholders and Indigenous communities places upwards pressure on O&M costs.
Impact on Capital	FortisBC has not included incremental capital related to increasing stakeholder and Indigenous engagement. However, failure to engage effectively will negatively impact planned capital programs.
Impact on Load / Revenues	Engagement activities support FortisBC's efforts to continue to grow and serve its customers. Failure to address this influence will place downward pressure on demand, particularly in the natural gas distribution system.

1

	Influence 4: 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.
Opportunities	FortisBC continues to experience system growth for both FEI and FBC driving increased demand as well as the need for increased investment.
Challenges	FortisBC has identified challenges including the need for investment in system integrity and reliability, increased maintenance and sustainment requirements, and increased physical and cyber security requirements to continue providing safe, reliable service to customers.
Response to Challenges and Opportunities within the MRPs	FortisBC has proposed the following as part of its MRPs in an effort to address these opportunities and challenges: • A five year rate plan which allows an increased utility focus on managing the business with a long-term view and increased operational flexibility to address the pace and growing scope of industry transformation; • Stable levels of O&M funding sufficient to address emerging pressures and an ability to efficiently allocate resources to address challenges and opportunities. • A capital forecast of Regular Capital and a unit cost approach for FEI Growth Capital to meet capital needs; • Inclusion of a combination of benchmark and informational service quality indicators focused on safety and reliability.

	Influence 4: 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.
Impact on O&M	FortisBC has included incremental O&M required to address this influence as follows: FEI • System Operations, Integrity and Safety - $2.650 million related to enhancing integrity management, maintaining new and existing assets, responding to increased compliance and safety requirements, • Cyber Security - $0.508 million related to implement and maintain technologies that address the evolving threat landscape, support the ability to respond to cyber security events, maintain system security and manage risk to infrastructure. • Data Analytics - $0.300 million related to improving data analytics capabilities to better support planned outages, asset management, optimized workforce deployment and predicting third-party damage. • Gas Control - $0.650 million related to the addition of four gas controller positions to provide 2-person gas control room staffing on 24/7 basis and for increased SCADA communications lines to enable increased system monitoring of field devices. • CEPA Participation - $0.700 million related to CEPA participation and to support continuous improvement of integrity management practices FBC • System Operations, Integrity and Safety - $0.504 million related to identifying and assessing tree health along right of ways, meeting Dam Safety Regulation, and supporting apprenticeship programs to meet anticipated staffing demands. • Cyber Security - $0.080 million related to managing cyber security requirements (see FEI above). • Data Analytics - $0.099 million related to improving data analytics capabilities (see FEI above).
Impact on Capital	FortisBC has prepared detailed capital forecasts for Regular Capital except for FEI Growth Capital which is managed under a unit-cost approach (see Section C3 of the Application). In addition, FortisBC has highlighted some anticipated Major Projects (see Section C3.3.3 and C3.4.2 of the Application for FEI and FBC, respectively).
Impact on Load / Revenues	This influence is not expected to impact load or revenues.

1

Influence 5: Increased need for innovation and the adoption of new technologies to improve operations, enhance customer service levels and meet decarbonization policy objectives.

Opportunities	Pursuing innovation and the adoption of new technologies will help mitigate policy-driven demand risks and proactively manage rate impacts while supporting GHG emissions reductions and helping customers meet their energy and emissions goals.
Challenges	A funding gap exists in supporting innovation and the adoption of new technologies.
Response to Challenges and Opportunities within the MRPs	FortisBC has proposed the following as part of its MRPs in an effort to address these opportunities and challenges: • Flexibility to innovate and adapt through a Clean Growth Innovation Fund that aims to accelerate the pace of clean energy innovation, achieve performance breakthroughs and cost reductions, and continue to provide customers with cost effective, safe and reliable energy solutions. The Clean Growth Innovation Fund will support research and development activities. The Fund will be managed outside of index-based O&M and is proposed as a based charge rider as follows: • FEI: $4.9 million collected monthly as $0.40 per customer per month • FBC: $0.5 million collected monthly as $0.30 per customer per month
Impact on O&M	Qualitatively, the purpose of the fund is to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and provide cost-effective, safe and reliable solutions for customers that may positively impact O&M costs. For example, research and development aimed at reducing fugitive emission could lower the costs of compliance with regulations.
Impact on Capital	Qualitatively, the Fund may positively impact capital costs. For example, research and development on renewable gas technologies aim to lower the cost of producing biomethane, thus reducing the cost of meeting renewable content gas targets.
Impact on Load / Revenues	Qualitatively, the Fund may positively influence load and revenues. For example, breakthroughs in appliance performance reduce customer costs and increases demand for natural gas over other more costly alternatives thereby positively impacting demand for FortisBC's energy solutions and services.

1.1.1 As part of the above response please explain if each of the "key regulatory measures" underpinning the Pan-Canadian Framework are likely to impact FEI and FBC during the proposed MRP term and if so, how.

Response:

The following provides an explanation of how the key regulatory measures underpinning the Pan-Canadian Framework are likely to impact FEI and FBC during the proposed term of the MRPs.

Federal Carbon Pricing Backstop

The federal carbon pricing backstop is not expected to materially impact FEI or FBC because the Province of B.C. has an existing carbon tax of $40 per tonne of carbon dioxide equivalent emissions which is expected to rise to $50 per tonne by 2021. Because of this, the federal carbon pricing backstop does not apply and has no impact.

Federal Clean Fuel Standard (CFS)

The full impacts of the federal CFS are not yet known as this policy remains under development. However, at this time, FEI expects the CFS to require gas distribution utilities to reduce the lifecycle intensity of gaseous fuels starting in 2023. The CFS is designed to allow multiple compliance pathways whereby regulated entities must hold the required amount of emissions reduction credits to meet their annual obligations. Examples of compliance pathways to reduce the lifecycle intensity of natural gas include blending natural gas with RNG or hydrogen, as well as carbon capture and sequestration.

Given that the CFS is expected to achieve the greatest GHG emissions reductions of any federal policy by 2030, FEI expects that it will need to commit additional resources to complying with this policy; however, the extent and scope will not be known until the CFS has been completed. For example, CleanBC's requirement for 15 percent renewable gas content may overlap to some degree with the requirements of the CFS, but this will not be known until the policies are completed and turned into legislation. FEI continues to work with policy makers with the goal that the federal CFS and provincial CleanBC policies can work effectively together. FortisBC will bring forward the impacts of the CFS once they are known and certain.

Federal Net Zero Energy Building Codes

The federal Net Zero Energy Building Code is not expected to impact FortisBC due to the existence of equivalent BC Building Code, which is anticipated to be aligned with the federal building code.

Federal Fugitive Methane Emissions Regulation

The impacts of the federal fugitive methane emissions regulation have not been developed so the impacts remain uncertain. FEI does expect that this regulation will place upward pressure on the cost of gas for FEI customers. FortisBC will bring forward the impacts of the federal Fugitive Methane Emissions Regulation once they are known and certain.

1.1.2 As part of the above response, please specifically address the CleanBC Plan.

Response:

The response to BCUC IR 1.1.1 provides a high-level summary of the significant elements of the CleanBC Plan (CleanBC or the Plan) which are expected to impact FortisBC. In order to avoid overlap, while providing an overview of the potential impacts of the entire Plan, the table below references back to the response to BCUC IR 1.1.1 where the information has already been covered.

Please also note that the detailed impacts of the CleanBC are not yet known since the Plan has not yet been turned into legislative mandates. Similarly, CleanBC currently lays out policy measures to achieve 75 percent of the Province's 2030 greenhouse gas emissions (GHG) targets so it is expected to continue to evolve. Please also refer to the responses to BCUC IRs 1.1.1 and 1.1.1.1 for additional discussion of the impact of CleanBC and other climate policies impacting FortisBC.

Sector	Initiative	Anticipated Impact	
		FEI	FBC
Transportation	Zero-emission vehicle mandate (100% by 2040)	• Please refer to the response to BCUC IR 1.1.1.	• Please refer to the response to BCUC IR 1.1.1.
	Renewable and Low Carbon Fuel Requirement Regulation (RLCFRR) increase to 20%	• Increase in demand for NGT and RG for transportation. • Please refer to the response to BCUC IR 1.1.1.	• Increase in demand for electricity
	Increased renewable gasoline and diesel production	• Reduced demand for NGT and RG for transportation	• Unknown
Built Environment (Buildings)	Net-Zero Energy Ready building code by 2032	• Reduced demand for natural gas • Decrease in customer attachments	• Unknown

Sector	Initiative	Anticipated Impact	
		FEI	FBC
Industry	New standards for building upgrades (retrofits) by 2024	• Reduced demand for natural gas • Decrease in customer retention	• Unknown
	Increase efficiency standards for heating equipment and windows	• Reduced demand for natural gas • Decrease in customer retention • Increase in demand for DSM incentives	• Reduced demand for electricity • Increase in demand for DSM incentives
	Investments in public housing to use less energy	• Reduced demand for natural gas	• Reduced demand for electricity
	15% renewable gas requirement	• Please refer to the response to BCUC IR 1.1.1.	• Unknown
	Help remote communities reduce dependence on diesel	• Increase in demand for CNG, LNG and RNG	• Unknown
	CleanBC Communities Fund	• Opportunity for investments in LNG and RG projects	• Increase in demand for DSM incentives
	Clean growth program for industry	• Increase in demand for DSM incentives	• Increase in demand for DSM incentives
	Switch 1,700 lower mainland freight trucks to natural gas and low or zero-carbon fuel by 2030	• Increase in demand for NGT and RG for transportation • Increased in NGT vehicle incentives	• Unknown
	Make heavy-duty vehicles more efficient with fuel efficiency improvements, education on driving practices	• Reduced demand for NGT	• Unknown
	Reduce methane emissions from upstream oil and gas operations by 45%	• Upward pressure on the cost of gas	• Unknown

Sector	Initiative	Anticipated Impact	
		FEI	FBC
	Industrial electrification	• Reduced natural gas demand	• Increase in electricity demand • Increase in demand for DSM incentives
	Regulatory framework for carbon capture and storage and direct air capture	• Opportunity to support reduction of customer and internal emissions	• Unknown
	15% renewable gas requirement	• Please refer to the response to BCUC IR 1.1.1.	• Unknown
Waste	95% organic waste diversion targets, including systems to capture 75% of landfill gas, as well as making better use of waste across all sectors of the economy, including renewing the BC Bioenergy Strategy	• Increase to renewable gas availability	• Unknown
Carbon Tax	Grow the carbon tax $5/year 2018 to 2021 with support for clean investments	• Increased cost to customers' total delivered cost of gas	• Unknown

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2.0 Reference: EVOLVING OPERATING ENVIRONMENT

Exhibit B-1, Section B1.2.2, pp. B-4 – B-6, B-12 – B-13

CleanBC Plan

On page B-4 of the Application, FortisBC describes the CleanBC Plan, including the three themes of: (i) cleaner transportation; (ii) improving the built environment; and (iii) cleaner industry. FortisBC also states: "The increase in the [carbon] 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."

On page B-6 of the Application, regarding the BC Energy Step Code and other local government initiatives, FortisBC describes certain local governments' plans to adopt 100 percent renewable energy and states that "[s]uch aggressive energy policies can ultimately constrain the outlook for FEI's traditional natural gas services in these jurisdictions."

On pages B-12 and B-13 of the Application, FortisBC states the following:

> FEI has seen year over year increases in new gas customer attachments since the beginning of the Current PBR Plan…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.

2.1 Please discuss whether, in consideration of the CleanBC Plan, FEI anticipates that annual load/demand and the number of customer attachments during the proposed MRP term will increase, remain flat, or decrease.

Response:

Climate actions plan, including the CleanBC Plan, the BC Energy Step code, and local government actions to strengthen their climate action initiatives, will constrain the outlook for FEI's traditional natural gas services. As these policies continue to solidify into legislative mandates, FEI anticipates an increasing potential for impact on new customer attachments and associated natural gas demand over time; however, the specific impacts remain uncertain and difficult to assess at this time for the term of the MRP.

The climate action plans that affect buildings, and thereby demand for natural gas in homes and businesses, are discussed below:

BC Energy Step Code (Step Code)

The Step Code provides municipalities with tools to increase the efficiency and performance of new buildings. To date, 14 local governments have adopted the Step Code in policy, programs or bylaws, and an additional 21 local governments are in the consultation stages of adoption. As municipalities seek to adopt the higher levels of the Step Code, FEI expects it to be more challenging for buildings to use traditional natural gas equipment. The adoption and step advancement rate of the Step Code by municipalities is dependant on a number of factors and continues to evolve and change as municipalities become more engaged in climate action. For example, as the Step Code increases building costs, some municipalities may opt to focus on more affordable housing measures rather than moving up levels of the Step Code. Further, the market for new housing is also slowing which may put pressure on municipalities to focus instead on reducing the development's regulatory burden and costs (such as permitting wait times) which could also affect the adoption of the Step Code in the short term.

CleanBC's Impact on the Step Code

As part of CleanBC, the provincial government is proposing a mandated gradual adoption of the steps of the BC Energy Step Code whereby all new buildings constructed in B.C. will be "net-zero energy ready" or 80 percent more efficient by a specified timeframe. This change will be enacted step by step and will apply to all new construction in the Province, where new homes, as compared to the current base BC Building Code, will be:

- 20 per cent more energy efficient by 2022;
- 40 per cent more energy efficient by 2027; and
- 80 per cent more energy efficient by 2032.

These accelerated energy performance requirements for new construction would reduce incremental annual demand. The impact would vary, depending on whether only new construction is impacted or if renovations are included.

CleanBC's Impact on Energy Efficiency and Electrification

The CleanBC Plan also calls for measures to expand energy efficiency improvements and electrification of buildings by fuel switching from natural gas appliances to electric heat pumps. CleanBC states that 70 thousand 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 the majority of those homes and businesses are heated with natural gas. Collectively, these actions represent a significant challenge to natural gas demand in the buildings sector. For example, as a starting point, if we were to assume these 70 thousand homes to be converted over the period from 2019 to 2030 are all existing FEI customers, FEI would experience a loss of approximately 35,000 residential

customers over the MRP term as they convert to electricity. The impact of the retrofits to electric heating in the 40 percent of commercial buildings will be in addition to these 35,000 residential customers and is more difficult to measure.

City of Vancouver Climate Emergency

At the municipal level, the City of Vancouver (CoV) recently adopted its Climate Emergency Response Plan in April 2019. Within that plan, Big Move No. 4 recommends that all buildings' space and water heating becomes zero emissions by 2025. In anticipation, FEI understands that many builders and developers with projects in the CoV are considering an earlier switch than 2025 as they believe it will facilitate a more streamlined zoning and permitting approval process. This policy remains under development; however, FEI believes it will reduce customer attachments, and negatively impact customer retention and demand.

Other Municipalities

A number of local governments, in addition to the CoV, have adopted policies to achieve 100 percent renewable energy by 2050. For example, 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. Municipalities and regional districts that have declared climate emergencies (as of May 2019) include:

> Vancouver, Richmond, Capital Regional District, Powell River, Islands Trust Council, Nanaimo, Regional District of Central Kootenays (declared a Climate Imperative, rather than an Emergency) and New Westminster.

These motions lay the groundwork to strengthen local governments' climate action plans, accelerate emissions targets, and reduce natural gas use in the building sector. As municipal climate emergency initiatives become more widespread, the reduction in customer attachments and natural gas load in the residential and commercial customer segment will be more pronounced.

More recently, FEI has noted that municipal policies more openly favor the installation of zero emissions energy systems in buildings. For example, the CoV's Zero Emission Catalyst Policy, approved in May 2018, provides developers with a 5 percent density increase (Floor Space Ratio or FSR)[1] in exchange for constructing zero emissions buildings. Other municipalities have supported their climate objectives by fast-tracking the approval of low or zero emissions

[1] https://vancouver.ca/green-vancouver/zero-emissions-buildings-tools.aspx#resources.

buildings ahead of other projects, creating a path of least resistance for developers and builders. In other more limited instances, municipalities through re-zoning approval are explicitly favouring electrically heated buildings and fast tracking approvals for buildings that do not use gas. Such policies and actions coupled with municipal climate emergency initiatives decrease customer attachments and natural gas load in the residential and commercial customer segments.

Overall, the impact is expected to be more pronounced at the local government level which is accelerating at a much faster rate as local government policy makers explore more ambitious low carbon strategies that have the potential to accelerate beyond existing provincial levels. The acceleration of local government climate policy ahead of provincial policy creates increased risk and difficulty in managing the various impacts throughout the Province. Depending on how these various activities unfold over time, customer attachments and load will be impacted.

Summary

In summary, all the actions from provincial and municipal governments represent a significant challenge to natural gas demand in the building sector. FEI is responding by strengthening its efforts to expand its innovative, clean energy solutions for buildings such as expanding renewable gas supply and is proposing to increase its support for innovative technologies through the Clean Growth Innovation Fund, as well as educating customers about the benefits of gas. FEI will also increase engagement with local governments, Indigenous communities and other organizations through the Climate Action Partners program in an effort to assist them in meeting their climate objectives through the adoption of FEI's lower emission offerings such as Natural Gas for Transportation (NGT). Over the term of the MRP, FEI will continue to focus on growing and retaining its customer base despite the more challenging operating environment. As such, during the MRP period, FEI has proposed incremental funding to support these efforts (please refer to the response to BCUC IR 1.1.1 and Section C2.4.2.3 of the Application). While these efforts will play a role in beginning to help mitigate some of the emerging pressures resulting from the policies noted above, the full extent of the impact on customer attachments and load is difficult to ascertain.

2.1.1 If FEI is anticipating increases in the annual load/demand and in the number of customer attachments, please discuss whether the increases are expected to be higher, similar, or lower than what was experienced during the current 2014-2019 performance-based ratemaking (PBR) plan (Current PBR Plan) and why.

Response:

Please refer to the response to BCUC IR 1.2.1.

2.2 Please discuss whether the BC Energy Step Code and other local Government initiatives are likely to impact FBC during the proposed MRP term and if so, please explain how.

Response:

It is difficult to ascertain the impact on FBC from the various Climate actions plan, including the CleanBC Plan, the BC Energy Step code, and local government actions to strengthen their climate action initiatives. As these policies continue to solidify into legislative mandates, FBC anticipates there will be reductions in demand as policies that improve energy efficiency, such as the BC Energy Step code, are adopted, while there will be opportunities for increased demand with electrification of space and water heating in buildings and the increased adoption of electric vehicles (EVs).

BC Energy Step Code (Step Code)

As described in the response the BCUC IR 1.1.2.1, the adoption and step advancement rate of the Step Code by municipalities is dependant on a number of factors and continues to evolve and change as municipalities become more engaged in climate action. As part of CleanBC, the provincial government is proposing a mandated gradual adoption of the steps of the BC Energy Step Code whereby all new buildings constructed in B.C. will be “net-zero energy ready” or 80 percent more efficient by a specified timeframe. These accelerated energy performance requirements for new construction would reduce annual demand. The impact would vary, depending on whether only new construction is impacted or if renovations are included.

Municipalities

A number of local governments are currently examining strategies to decarbonize heating, cooling and transportation networks or declaring climate emergencies, which require the local government to undertake changes to areas such as building construction, energy systems, transportation to address climate change concerns. This may provide opportunities for load growth in buildings and increased demand for electricity and EV charging infrastructure, the extent of which is uncertain over the MRP period.

2.3 Please discuss FEI's expectations regarding new housing starts and completions in BC over the proposed MRP term and the impact this might have on FEI.

Response:

Generally, the new housing construction market is expected to soften over the early period of the MRP as compared to current levels largely due to impacts of recent policy and regulation changes that affect the purchase of a home, such as tightening mortgage rules, the foreign buyer's tax, and the speculation tax. As a result, gross customer additions are expected to be lower over the early part of the MRP as compared to that of the Current PBR Plan. Housing starts/completions for the middle and latter part of the MRP period are less certain. Accordingly, FEI expects that capital expenditures related to customer growth will be lower overall during the MRP term as compared to the Current PBR Plan term. Further, additional efforts and funding directed towards the conversion market will be required in order to help offset some of the decline in customer attachments levels from the construction market.

2.4 Please explain whether, based on FortisBC's description of the evolving operating environment, and in particular the expected impacts of the CleanBC Plan, create an increased risk of stranded assets for FEI.

Response:

Yes, if left unmitigated, the evolving operating environment and the impacts of the CleanBC Plan have the potential to create an increased risk of stranded assets over the long term by constraining FEI's ability to attach, retain, and deliver energy to its customers. However, there is considerable uncertainty in how the transition to a lower carbon economy will unfold. FortisBC discussed some of the inherent challenges and uncertainties in transitioning to a lower carbon economy in its Clean Growth Pathway submission:

> BC's electric and gas energy systems work in tandem to provide reliable energy to British Columbians. Both systems complement one another, providing redundancy and a low-cost solution to delivering energy to British Columbians. FortisBC believes that the provincial pathway should be guided by strong analysis and pursue a strategy that utilizes 'every tool in the toolbox': all of our provincial energy resources and existing infrastructure will be needed to achieve long-term GHG emissions reductions.

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

…

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

...

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

gas flowing through the system while maintaining the use of that system is a prudent and low-cost strategy to ensure that BC achieves its climate targets.[2]

While policy developments continue to evolve and unfold, FortisBC's alternatives for mitigating the increased risk of stranded assets include:

- Developing pathways to pay for the early retirement of assets[3]; and/or
- Developing alternative energy products and services that leverage existing assets while also reducing emissions.

FortisBC believes its assets will play a critical role in the transition towards a lower carbon economy and because of this, has opted for the second approach, developing alternative energy products and services that leverage existing assets while also reducing emissions.

As noted on page B-7 of the Application, FEI included various GHG emissions reduction scenarios in its 2017 LGTRP and highlighted the sizeable role FEI's assets can play in reducing emissions, which mitigates policy-driven risks of downwards pressure on demand. For example, FEI's contributions towards the achievement of CleanBC through renewable gas delivered through FEI's distribution system provides 75 percent of the Plan's total emissions reductions in the built environment, which signifies that the Province expects the gas system will continue to play a central role in the provincial strategy to reduce GHG emissions in buildings. Therefore, FEI's response has appropriately focussed on developing alternative energy products and services that leverage its existing assets including reducing their lifecycle carbon intensity. This strategy is reflected in FortisBC's MRPs, including the following elements:

- Targeted incentives that seek to address the challenges and opportunities in the external environment. Specifically, the proposed targeted incentives seek to create outcomes that are aligned with climate policy and emissions reductions by focussing on growth in renewable gas, growth in clean transportation and reducing emissions;
- A five-year rate plan which allows an increased utility focus on managing the business with a long-term view and increased operational flexibility to address the pace and growing scope of industry transformation;
- Stable levels of O&M funding sufficient to address emerging pressures and an ability to efficiently allocate resources to address challenges and opportunities. This includes incremental funding proposed for Customer Expectations and Engagement noted in Section C2.4.2.3 of the Application; and
- A Clean Growth Innovation Fund that provides greater flexibility to innovate and adapt to the changing environment. Specifically, the Clean Growth Innovation Fund aims to

[2] Appendix A5, Clean Growth Pathway to 2050, p. 5, 13.
[3] Pathways to early retirement can include actions such as accelerated depreciation.

accelerate the pace of clean energy innovation, achieve performance breakthroughs and cost reductions for customers in support of a lower carbon future.

In summary, the proposed MRPs help position FortisBC to continue to provide service to customers as the economy transitions towards a lower carbon future. This response is appropriate and necessary to mitigate any increased risk of stranded assets.

2.4.1 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.2.4.

2.4.2 If yes, please explain how FEI proposes to mitigate these risks.

Response:

Please refer to the response to BCUC IR 1.2.4.

2.5 Please separately explain in detail how the CleanBC Plan's actions regarding cleaner transportation impact FEI and FBC.

Response:

One of the key pillars of CleanBC is initiatives to reduce emissions from transportation applications, which make up about 39 percent of the Province's total GHG emissions. FEI and FBC, among other utilities in the Province, can play a key role in helping to reduce GHG emissions from the transportation sector through initiatives that enable the use of natural gas (including renewable natural gas and hydrogen) and electricity as fuel for transportation. These initiatives include the provision of fueling infrastructure for natural gas, charging infrastructure for battery-EVs and support for end-use customers of lower carbon fuels.

In FEI's case, the CleanBC Plan references the following:

- "Make our fuel cleaner by increasing the low carbon fuel standard to 20% by 2030 and increasing the production of renewable transportation fuels"; and
- "Make vehicles run cleaner by increasing tailpipe emissions for vehicles sold after 2025".

It is not yet clear to FEI how these two pieces of policy will affect the medium- and heavy-duty vehicle sectors, where FEI has been active with its NGT program. FEI notes, however, that the CleanBC Plan states on page 19:

> The private sector has a big role to play in this new clean energy infrastructure development [referring to charging for zero emissions vehicles], and the Province will be addressing barriers to investment in commercial charging, and hydrogen fueling…

In the future, FEI may have a role in investing in the provision of hydrogen and charging infrastructure and services to commercial fleets, as FEI currently does in its NGT program.

The Province of BC's Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) has been a key enabling regulation to initiate and carry through the adoption of natural gas as a transportation fuel in BC since 2012. The GGRR also includes recent amendments to the prescribed undertakings to include renewable natural gas (RNG) as a transportation fuel for natural gas transportation customers, which supports the policy statement quoted above regarding "increasing the production of renewable transportation fuels". The inclusion of RNG for transportation applications in the GGRR provides further opportunities for GHG emissions reductions due to the much lower carbon intensity of RNG as compared to conventional natural gas, and even more so, conventional diesel fuel.

With respect to FBC, the CleanBC Plan sets out initiatives such as the Zero Emissions Vehicle standard for passenger vehicles and provincial investments in home, workplace and public charging stations. Although the pending EV Charing Inquiry presents some uncertainty around the details of FBC's role in supporting the adoption of EV charging infrastructure, CleanBC's clean transportation initiatives signal the importance of utility involvement to help ensure that the benefits associated with these investments are realized, particularly considering the challenging economics of investments such as for direct-current fast charging stations. FBC's intention at this time is to continue to invest in direct-current fast charging stations to support transportation corridors, and also to develop programs to provide incentive funding to customers for EV charging at home (single-family and multi-unit dwellings) to help manage the impact of the associated increased load on FBC's system.

Section 2.4.2 of the CleanBC Plan talks about ways to make industrial transportation cleaner, which should also create opportunities for FEI and FBC to support medium and heavy-duty vehicle fleets and marine transportation in this regard. Page 42 of this section of the CleanBC

Plan states specifically that natural gas is an important transitional fuel that can provide emissions reductions while cleaner heavy-duty vehicles are being developed.

As the CleanBC Plan is turned into legislated mandates, FEI and FBC believe it will provide opportunities to implement programs, initiatives and investments that support the delivery of lower carbon transportation fuels to customers.

2.5.1 With regard to each of FEI and FBC, please explain specifically how the cleaner transportation action is addressed in the proposed MRP, including if FEI/FBC is proposing additional O&M and capital expenditures during the MRP. If yes, please explain how much it estimates these expenditures to be and where they are included within the MRP (formula O&M, controllable capital, flow-through, etc.).

Response:

FortisBC has not prepared a forecast of its O&M and capital for its investments in clean transportation. Clean transportation is included under the category of Investments in a Clean Growth Future. Under the MRPs, FortisBC has proposed to forecast these investments annually through the Annual Review process (please refer to Section C4.4.2 of the Application). Accordingly, FortisBC will prepare a forecast for 2020 O&M and capital related to these investments in the 2020 Annual Review when filed.

With regard to addressing clean transportation in its MRPs, FortisBC has included Targeted Incentives to support and promote the adoption of clean transportation, including those for NGT and EVs[4]. Please refer to the responses to BCUC IRs 1.96.9 and 1.96.9.1 for further discussion of the treatment of these expenditures during the term of the MRPs.

FortisBC has also proposed a Clean Growth Innovation Fund which seeks to accelerate the advancement and adoption of technology including technology related to transportation end-uses. This Fund helps address funding gaps for innovation and is discussed in detail in Section C6 of the Application, including the treatment of expenditures under the Fund.

[4] FBC intends to develop targets for EV following the conclusion of the Electric Vehicle Charging Inquiry.

2.5.2 Please explain what impact the cleaner transportation plans are expected to have on each of FEI and FBC's forecast demand during the proposed MRP term.

Response:

The continued conversion of current diesel-fuelled vehicles to natural gas vehicles is akin to FEI attaching new customer dwellings to its natural gas distribution system. This continued conversion to natural gas powered vehicles will continue to increase the overall demand for natural gas that FEI delivers to its customers, all else being equal. This in turn should lead to higher utilization levels of FEI's natural gas distribution system, which will enable more efficient operation of the gas system as a whole. This is because natural gas demand for transportation is not seasonal and sensitive to weather or temperature fluctuations, unlike demand from FEI's residential customers. This flatter load profile of transportation enables a more efficient overall operation of FEI's gas distribution system.

As discussed in the response to BCUC IR 1.98.2 and set out in Table C8-3 on page C-161 of the Application, FEI has proposed an incentive for FEI to achieved a targeted level of NGT demand during the MRP term.

Similarly, for FBC, continued adoption of EVs, as supported by the provincial government's Zero Emissions Vehicle (ZEV) mandate, will result in an overall increase in electric load over the proposed MRP term. Generally speaking, the ZEV mandate is expected to positively impact demand for electricity. FBC is currently working to further understand the potential system impacts that may result from this increased load, particularly at the local distribution level, and the mitigating measures that may be required. As noted in Section C8.3.6 of the Application, FBC intends to develop targets related to the deployment of EV charging infrastructure following the conclusion of the BCUC's Electric Vehicle Charging Inquiry.

2.5.3 Please discuss what impact the cleaner transportation plans are expected to have on FEI's Greenhouse Gas Reduction Regulation (GGRR) initiatives. Please outline the anticipated capital spending in each year of the proposed MRP and the expected rate impact to non-bypass customers after any anticipated take-or-pay customer commitments.

Response:

While the CleanBC Plan has not yet been turned into legislative mandates, FEI generally expects the legislative mandates to support increased investments in clean transportation services as prescribed undertakings under the GGRR. Please also refer to FEI's response to BCUC IR 1.2.5.1 where FortisBC explains the process for reviewing the associated forecasts under the proposed MRPs.

On page B-5 of the Application, FortisBC describes various actions outlined in the CleanBC Plan related to "Improving the Built Environment" and states: "Collectively, these actions represent a significant challenge to natural gas demand in the buildings sector."

2.6 Please clarify if any of the actions related to the theme "Improving the Built Environment" are expected to impact FBC during the proposed MRP term, and if so, how.

Response:

Please refer to the response to BCUC IR 1.2.2.

FortisBC further states on page B-5 of the Application: "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."

2.7 Please quantify and describe FEI's planned investment in Renewable Natural Gas (RNG) and hydrogen infrastructure during the proposed MRP term and explain how these investments would be classified within the proposed MRP (i.e. controllable capital, forecast capital, etc.).

Response:

FEI's view is that the amount of investment in RNG will range widely depending upon FEI's scope of ownership of RNG facilities and cannot provide a meaningful forecast at this time.

FEI has begun investigating the feasibility of hydrogen injection into the natural gas system, but has not developed a forecast for investment in hydrogen infrastructure given the early stage of the Company's investigation. Hydrogen has the potential to play a significant role in fulfilling the CleanBC renewable gas target; however, study of the technical and financial feasibility of hydrogen injection is required and ongoing.

FortisBC has proposed that its investments that are aligned with its Clean Growth Future submission, including renewable gas, should be forecast annually outside the index-based O&M mechanism and Regular capital forecasts (please refer to Section C4.4.2 of the Application). Further, RNG costs are 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 customers through the BVA Rider (please refer to Section C4.4.2.3 of the Application).

2.8 Please describe FEI's R&D plans and provide an estimate of the expected R&D spending during the proposed MRP by year, including how this spending will be classified in the MRP.

Response:

As noted in the response to BCUC IR 1.2.7, FEI is currently investigating the feasibility of hydrogen injection and distribution which is at an early stage. Accordingly, FEI does not have a fully developed R&D plan at this time. However, it is expected that the development of hydrogen injection and distribution infrastructure would follow a typical pathway for the introduction of new technology.

This pathway starts with small initial investments in studies, literature research, and the development of more detailed plans. Since hydrogen injection is not common in North America, study of its technical feasibility, which will include the involvement of technical regulators, is necessary.

These actions will be followed by investment in pilot projects, possibly in partnership with other utilities, industry partners, and government. The focus of this stage will be to demonstrate technical feasibility while gaining an understanding of cost and operation performance.

FortisBC intends to fund research and development related to renewable gas through the Clean Growth Innovation Fund during the MRP term. As noted in Section C6.6 of the Application, funds are proposed to be collected from customers through a basic charge rate rider of $0.40 (FEI) and $0.30 (FBC) per customer, per month. Annual expenditures in research and development will be funded by the amounts collected through the Innovation Fund.

2.9 Please explain the types of piloting and demonstration FEI plans to perform during the MRP.

Response:

If approved, the Innovation Fund will allow the development of piloting and demonstration projects in various areas, including hydrogen injection into natural gas pipelines, production of wood-based biomethane, and other renewable gas technologies which seek to lower emissions.

2.10 Please confirm, or explain otherwise, that the additional regulatory support, education and engagement of gas system stakeholders will be captured within the formula O&M and how much additional spending FEI estimates for these activities.

Response:

To the extent that the regulatory support, education and engagement can be supported by existing resources, or form part of a broader initiative, they would be captured within the index-based O&M. Incremental requirements that are focused entirely on Clean Growth Future initiatives such as hydrogen would be forecast each year in the Annual Review process. Cost estimates for the additional regulatory support, education and engagement of gas system stakeholders for hydrogen injection and distribution have not been developed at this time due to the early stage of development.

3.0 Reference: EVOLVING OPERATING ENVIRONMENT

Exhibit B-1, Section B1.3, pp. B-9 – B-15

Customer Expectations

On page B-9 of the Application, FortisBC states: "FEI's operating environment is shaped by evolving customer expectations, both from a service delivery standpoint as well as customers' attitude and preferences towards energy solutions."

3.1 Please clarify these "evolving customer expectations." What are they, and how have they been communicated to FEI (i.e. through customer engagement and surveys, open houses, etc.)?

Response:

Evolving customer expectations from a service delivery standpoint include the ability for customers to be digitally connected with the providers of their services, have greater choices and options, be empowered with information, have the ability to self-manage their energy use, as well as their overall expectations for what the experience should look and feel like. With respect to customers' attitude and preferences towards energy solutions, customers are increasingly focused on energy efficiency, looking for sustainable energy options and are becoming more engaged in energy choices and options available to them while still expecting reliability, good customer service and reasonable prices.

Insights into customer expectations and attitudes come from a variety of sources including:

- customer service operating metrics;
- market research;
- customer engagement activities such as the MyVoice research panel; and
- investigation into the strategies and tactics that other industries and North American utilities are employing to meet evolving customer expectations and needs.

An example of a customer service metric that provides insight into changing expectations is the adoption rates of Account Online. Comparing January 2017 to January 2019, FortisBC experienced a 57 percent increase in the monthly number of transactions completed by all Account Online users.

With respect to market research, the Companies regularly complete studies and research to understand customer preferences and attitudes. For example, recent market research explores the channels customers prefer to use to contact the company while another explores the expectations, environmental attitudes and energy beliefs of British Columbians.

Customer engagement activities such as the MyVoice online research panel, which includes about four thousand FortisBC customers, also provide insight into the changing expectations of customers by getting first hand customer feedback on proposed programs and services.

Finally, FortisBC reviews case studies and comparative insights into programs and strategies that have been successful at other utilities, as well as information about energy solutions that are gaining traction or that have hit roadblocks. This information helps FortisBC identify trends and opportunities that customers might benefit from.

Please also refer to the response to CEC IR 1.33.2 and BCSEA IR 1.15.2.

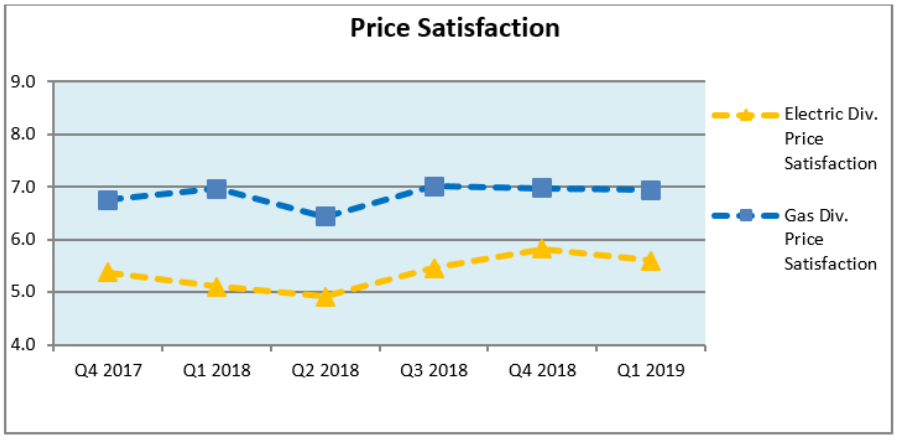
3.2 Please compare and contrast the (i) expectations, (ii) levels of satisfaction, and (iii) attitudes and preferences towards energy solutions of FEI's customers versus FBC's customers.

Response:

Although customer expectations are changing in a broad sense, customer experience expectations are consistent amongst gas and electric customers. Where differences may exist, they are typically relatively minor and are largely attributable to regional differences as well as demographic differences. For example, although both groups of customers expect a variety of channel options, a greater proportion of electricity customers have a marginal preference for the phone rather than online service, as compared to gas customers. In this case, the difference has been attributed to demographics because FEI has a larger percentage of customers who are less than 35, which is the group of customers that tends to prefer digital options.

Satisfaction scores for each company tend to move in parallel, but FEI scores are slightly higher than FBC. In general, FortisBC believes this difference is primarily associated with field service experiences and the price customers pay for electricity and natural gas. That is, FBC customers have fewer interactions with field technicians than FEI customers do. Field visits for gas odour response and gas meter exchanges typically result in higher, more favourable responses from customers. As a result of the smaller sample size of field visits for FBC, a few lower scores can drive a lower overall customer satisfaction score because field service quality accounts for 25 percent of the satisfaction index calculation. Concerning price, FEI customers typically indicate a higher satisfaction in this category. The chart below demonstrates this difference based on recent history: [5]

[5] CSI Survey, mean score for question B3.3, "Please use a scale of 1 to 10 where 1 is "Not at all satisfied" and 10 is



Similar to customer expectations, market research and engagement activities indicate that overall preferences and attitudes about energy solutions are largely similar amongst FortisBC customers. Differences that may exist are likely attributable to political, regional and demographic factors. For example, research indicates that environmental attributes and cost are important factors to most customers; however, British Columbians located on the Coast are more likely to prioritize environmental attributes over cost whereas British Columbians located in the Interior and Northern regions of the province are more likely to prioritize cost over environmental attributes.

3.3 If customer satisfaction varies between FEI and FBC, please discuss the likely reasons why, and how this impacts each utility's response to customers, if at all.

Response:

Please refer to the response to BCUC IR 1.3.2.

On page B-10 of the Application, FortisBC describes its understanding of customers' and stakeholders' expectations obtained through engagement activities performed during preparation of the most recent long-term resource plans.

"Extremely satisfied. The price you pay for natural gas/electricity."

3.4 Please compare and contrast the engagement activities performed in preparation for the long-term resource plans versus the preparation of this Application.

Response:

FortisBC views the engagement activities for the long-term resource plans and the MRPs (or other forms of revenue requirement applications that may be submitted from time to time) as being interrelated and ongoing. Although specific engagement events are planned to meet the specific needs of one filing or the other, the feedback obtained from each event can, and often does, inform both filings. Similarly, FortisBC, on an ongoing basis, conducts numerous stakeholder engagement activities for a range of purposes in order to deliver energy solutions to its customers. In this way, FortisBC views all customer and stakeholder activities as connected and informative for both FortisBC's long-term resource plans and revenue requirements applications, including the proposed MRPs.

It should be noted, however, that there are important differences between the proposed MRPs and the long-term resource plan (LTRP) filings that drive differences in the design of the engagement events undertaken and the parameters under which stakeholder feedback can effectively impact each of the submissions. For example, the resource plans examine a 20-year time frame, involve an approximately 2-year development cycle and provide guidance and context for how the utilities plan to address customer needs, infrastructure requirements, government policy and more under a range of future scenarios. The proposed MRPs, in contrast, are shorter term and operational in nature. The longer-term planning document, therefore, offers more opportunity for a wider range of stakeholders to provide input on planning aspects like risks and opportunities facing the companies or analytical methods and results used to assess different long range scenarios. The nearer-term MRPs, which have a much shorter preparation cycle, require input from stakeholders that are familiar with the rate regulation generally and the regulated energy utility industry specifically. These stakeholders are therefore typically the Utilities' interveners. Because of the operational nature of the proposed MRPs or other revenue requirement submissions, there is a narrower band of factors over which stakeholder input can affect the final submission.

Further, FortisBC considers all stakeholder input received throughout its engagement activities and, where practical, implements such feedback where it supports providing safe and reliable energy solutions at the lowest reasonable cost now and in the future.

With the foregoing in mind, FortisBC provides the following discussion comparing and contrasting the engagement activities undertaken during the LTRP process and those undertaken during development of the proposed MRPs. The discussion is divided into the following areas:

- Purpose and objectives of the engagement activities;

- Areas and highlights of the discussion; and
- Stakeholders engaged.

1. Purpose and objectives of the engagement activities

The engagement activities undertaken during FortisBC's most recently completed LTRP processes were not able to also meet all of the needs of the MRPs due to the difference in the nature of the filings and, to some degree, due to the time passed since filing the LTRPs. The additional engagement activities undertaken to support the development of the MRPs therefore had the following similarities and differences to the activities undertaken during the LTRP processes:

- Some of the stakeholder consultation conducted in support of the MRPs were for the specific purpose of selecting a vendor to conduct benchmarking studies and to reach an agreement on broad terms and parameters of the studies (see page 48 of the MRP submission) as was directed by the BCUC. None of the consultation activities during the LTRP processes were undertaken for this specific purpose.
- Discussions concerning the MRPs were focused on the actions and related expenditures of FortisBC during the 5-year term from 2020 to 2024. Many of these activities were identified with consideration for the longer term planning horizon examined by the LTRPs.
- Discussions concerning the LTRPs were more directed at the longer term (20-year) planning horizons of each of the LTRPs, and helped to identify the 4-year action plans in the LTRPs which more directly informed some of the 5-year MRPs' actions and expenditures.
- Discussions specific to development of the proposed MRPs focused on developing the ratemaking framework and examining alternative approaches whereas discussions during the LTRP processes were intended to address a wide-range of longer term planning issues with implications for the respective utilities, including 4-year action plans.
- LTRPs provide a comprehensive 20-year view of FortisBC's overall trajectory and consider broader energy policy issues and related matters of public interest, so their subject matter could be considered less specialized than the MRPs. As such, FortisBCs LTRP engagement activities spanned eight expert group meetings, workshops in 13 communities across BC, and online discussion boards with about 50 residential and commercial customers.
- Separate LTRPs for the electric and natural gas utilities were developed, with some stakeholder engagement activities for each utility's LTRPs also conducted separately (though the implications of any feedback received were shared between the utilities). In

contrast, stakeholder consultation conducted as part of developing the MRPs was conducted for both utilities at the same time.

In its efforts to develop MRPs that consider the interest and issues of concern to interveners, FortisBC initiated a number of discussions with interveners in 2017 and 2018. Please refer to Section B2.5 of the Application (page B-58, "Intervener Discussions and Feedback"). Additionally for the proposed MRPs, FortisBC has considered the feedback provided from stakeholders for the recent LTRPs. The feedback revealed customer and stakeholder support for FortisBC to pursue innovation and growth to support clean and cost effective energy solutions. During the LTRP engagement processes, customers and stakeholders highlighted that energy and emissions policy falls outside of their core competence or their direct sphere of influence. As such, customers and stakeholders rely on FortisBC to provide the desired energy solutions.

2. Areas and highlights of the discussion

Many of the themes and topics of discussion during the LTRP processes carried forward into the development of the MRPs, particularly wherever the nearer term activities and expenditures put forward in the MRPs are intended to address longer term risks and opportunities identified through the Companies' LTRPs.

MRPs

Discussions held and stakeholder feedback received included the following topics:

- A performance review and highlights of the Current PBR Plans;
- Review of other jurisdictions "next gen" PBR plans;
- Discussion of preferences for modifications to the Current PBR Plan or adoption of another framework (scope of next proceeding);
- Discussion of options for rebasing;
- Key themes of the next generation PBR application including Engagement, Investment and Innovation; and
- A comparison of multi-year rate plans compared to cost of service regulation.

These activities are summarized in Section B2 starting on page B58 of the MRP Application.

LTRPs

Topics discussed during FortisBC's long term resource planning stakeholder engagement activities included:

- The resource planning process, inputs and analytical results;

- The evolving energy planning environment;
- Forecasting methods and results;
- FortisBC initiatives and expectations;
- Energy and emissions policy and regulation;
- Programs to help customers and communities manage energy costs and emissions, such as C&EM, RNG and NGT;
- Advanced metering and billing options; and
- Coordinating activities between utilities and municipalities.

These activities are summarized in Section 7 of FEI's 2017 Long Term Gas Resource Plan (LTGRP) and Section 10 of FBC's 2016 Long Term Electric Resource Plan (LTERP).

3. Stakeholders engaged

MRPs

Stakeholders involved included representatives from the BCOAPO, BCSEA, ICG, BCMEU, CEC and MoveUP and BCUC Staff. These are the interveners who regularly participate in the Annual Reviews for the current PBR for FEI and FBC. Each of these stakeholder groups, except MoveUP, also participated in either or both of the FEI LTGRP and FBC LTERP. FortisBC also met with representatives from the Ministry of Energy, Mines and Petroleum Resources and the BC Business Council as part of the MRP consultation process.

LTRPs

The list of stakeholders that FortisBC engaged for the 2016 LTERP and the 2017 LTGRP include the following:

- First Nations Energy and Mining Council;
- One First Nation in the BC Interior;
- Multiple B.C. municipalities;
- BC Ministry of Energy, Mines and Petroleum Resources;
- Community Energy Association;
- Commercial Energy Consumers Association of BC;
- BC Business Council;
- Greater Vancouver Board of Trade;
- Union of BC Municipalities;

- BC Public Interest Advocacy Centre;
- BC Sustainable Energy Association;
- Pembina Institute;
- Northwest Gas Association;
- Residential and commercial customers;
- Multiple third-party utilities across the Pacific Northwest region; and
- The BCUC (as an information provider).

3.5 Please discuss whether FBC and/or FEI's most recent long-term resource plans incorporate and reflect the policies and mandates regarding decarbonization, particularly the CleanBC Plan, and if so, please explain how.

Response:

Since the CleanBC Plan was published months after the Companies' most recent long-term resource plans were submitted, neither FEI nor FBC could address the specific policy wording within CleanBC in their long-term resource plans; however, a number of the eventual mandates of CleanBC were considered within the resource plans. For example, FEI's 2017 LTGRP incorporates a range of future scenarios that considered climate related policy and action, and incorporated Appendix E – a preliminary analysis of ways in which the natural gas infrastructure could help to decarbonize the Province's energy supply. As another example, FBC's 2016 LTERP examined scenarios for EV adoption.

It should be noted that the Companies update their long-term resource plans at regular intervals using the most recent information available; however, the resource plans reflect a snapshot in time. FBC's 2016 LTERP (submitted November 30, 2016) and FEI's 2017 LTGRP (submitted December 14, 2017) incorporated relevant information available at the time of analysis on decarbonization policy actions and mandates, but could not anticipate and address specific policies of CleanBC, published in December 2018.

Further, the 2016 LTERP Planning Environment section did include a discussion of the initiatives of the BC Climate Leadership Team (CLT), formed in 2015, and the BC Climate Leadership Plan (CLP), released in August 2016, which contained recommended actions to reduce provincial GHG emissions. FBC then incorporated the relevant items from the CLT and CLP in the 2016 LTERP load scenarios, carbon price scenarios and portfolio analysis. The 2016 LTERP load scenarios included load drivers such as potential fuel switching between natural gas and electricity for space and water heating, increased rooftop solar penetration and

increased EV growth. The portfolio analysis included an assessment of clean and renewable resource options.

In its Planning Environment section, FEI's 2017 LTGRP discussed GHG emissions reduction actions proposed by the new government that emerged from the May 2017 provincial elections. This discussion helped inform the 2017 LTGRP's forecast scenario analysis and impacted inputs such as expectations about how provincial carbon tax rates would evolve throughout the planning horizon.

FBC and FEI plan to incorporate any relevant policies and mandates regarding decarbonization, including the specifics of the CleanBC Plan, in their next LTERP and LTGRP, to be submitted to the BCUC by December 1, 2021, and March 31, 2022, respectively.

FEI further states on page B-14 of the Application:

> FEI invests significant effort in encouraging new customers to connect to the natural gas system and to keep existing 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.

3.6 Please discuss whether, in consideration of the Provincial Government policy directions and mandates, FEI intends to divert some of its resources (financial and non-financial) from its current focus on attracting and retaining traditional natural gas customers to investigating new energy solutions.

Response:

FEI intends to continue to add and retain customers while also serving the new and emerging energy needs of its customers.

Beyond FEI's statutory obligations to serve, FEI's efforts to acquire new customers are also in response to customer demand. As demonstrated by Figures B2-1 and B1-2 on page B-13 of the Application showing FEI customer attachments and residential market share, there is currently a desire and preference from customers for natural gas. Customers want natural gas for heating and hot water, but also for convenience appliances. FEI has seen burner tips per new residential attachments that average four appliances per new residential customer. Cost savings and affordability are also very important to customers. Natural gas is substantially less expensive than other energy sources and the cost savings from using natural gas helps

customers manage affordability challenges they may face. Further, FEI's efforts to attract and retain customers are beneficial to existing customers. The addition of new customers helps spread fixed cost over a greater base, helping to offset other rate pressures. FEI therefore believes that it should continue to invest resources into the addition of new and retention of existing customers.

FEI's efforts to attract and retain customers have not detracted from its focus in other areas, and FEI has, at the same time, continued to pursue and investigate new energy solutions. As noted in the Application, FEI provides a range of energy solutions that are aligned with Provincial Government direction and mandates around reducing emissions. For example, FortisBC's programs help convert customers to cleaner sources of energy in transportation and buildings, provide renewable energy options for new and existing customers, and reduce emissions through its DSM programs by increasing efficiencies.

4.0 Reference: EVOLVING OPERATING ENVIRONMENT

Exhibit B-1, Section B1.5.1.3, pp. B-18 – B-20; FEI Inland Gas Upgrades Project CPCN Application proceeding, Exhibit B-2, BCUC IR 6.3

Increasing Investments Needed for System Integrity

On page B-18 of the Application, FEI states: "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."

4.1 Please explain what the third-party activities around assets and transmission line ROW that require permits are and why they are increasing.

Response:

Third-party activities around assets and transmission line right of ways are primarily local government and Ministry of Transportation and Infrastructure projects such as road widening and utility upgrades, as well as private land development and densification. The increasing permits are the result of increasing activity around FEI's assets, improved awareness of the requirement for permits when working around FEI's assets, and a change in regulation that increased the safety buffer around assets and transmission line right of ways where permits are required.

On page B-20 of the Application, FEI describes two Major Projects it plans to undertake, including the currently in progress Inland Gas Upgrades (IGU) Project Certificate of Public Convenience and Necessity (CPCN) Application (IGU CPCN).

In response to BCUC information request (IR) 6.3 in the IGU CPCN proceeding, FEI states the following:

> FEI also recognizes that with the approval of the Application, preparation of a CPCN for the TIMC Application in mid-2020, and other ongoing major projects, there will be a need for additional resources going forward. As such, FEI has established a Major Projects group to manage and execute large capital projects from initiation to execution. The Major Projects group is staffed with internal resources with experience in developing and executing major projects.

4.2 When did FEI establish the Major Projects group?

Response:

FEI established the Major Projects group in February 2018.

4.3 Is the Major Projects group considered a separate department for O&M purposes or is it part of an existing O&M department? If part of an existing department, please explain which one.

Response:

Major Projects is a separate department for O&M purposes.

4.4 How many Full Time Equivalents (FTEs) are currently in the Major Projects group and how many are expected to be in the group during the proposed MRP term.

Response:

There are currently 19.72 Full time Equivalents (FTEs) in the Major Projects group. FortisBC does not have a specific FTE forecast for the Major Projects group over the MRP period. FTE requirements will vary based on capital project approval and execution.

4.5 Please provide the annual O&M and capital expenditures related to the Major Projects group since its inception.

Response:

The Major Projects group was established in 2018. In 2018, the Major Projects group incurred $0.5 million of O&M and $0.2 million of capital. Up to May 31, 2019, the Major Projects group incurred $0.3 million of O&M and $1.4 million of capital. The Major Projects group supports all Major Capital projects, which amount to in excess of $100 million of annual capital spending.

4.6 What is the forecast annual O&M requirement for the Major Projects group during the MRP term? Please provide a description of these forecast expenditures.

Response:

FEI is proposing an index-based formula approach to determine overall O&M funding for the MRP period. As a result, FEI does not have specific O&M forecast amounts for the Major Projects department over the MRP period.

B. EVALUATION OF THE CURRENT PBR PLANS

5.0 Reference: EVALUATION OF THE CURRENT PBR PLANS
Exhibit B-1, Section A1.3.2, pp. A-5– A-7
O&M

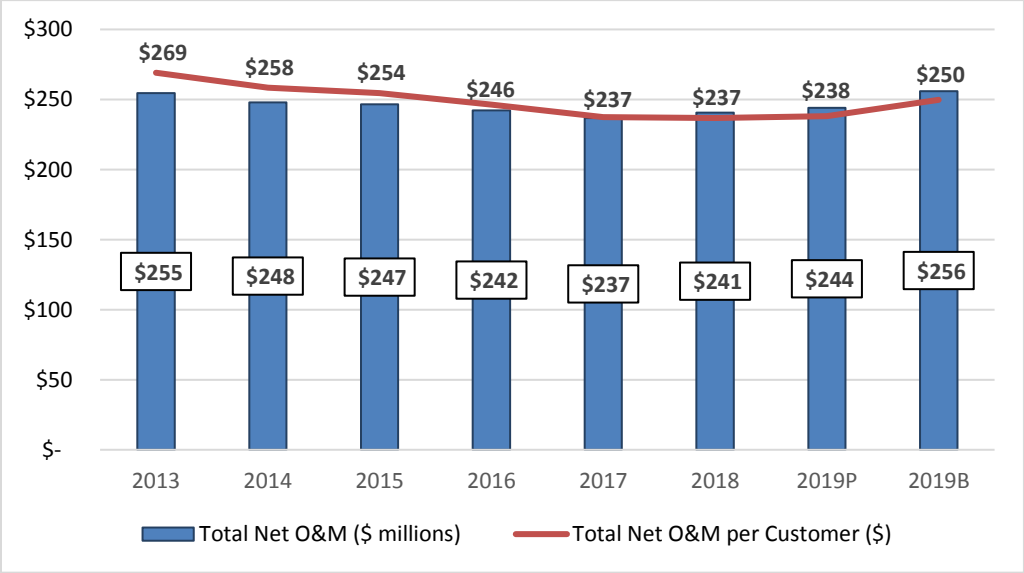
In Figures A1-1 and A1-2 on pages A-6 and A-7 of the Application, FortisBC shows the actual net O&M in real dollars from 2013 to 2019 Base for FEI and FBC, respectively.

In footnote 2 on page A-6 of the Application, FortisBC states: "FEI capitalized overhead rate is proposed to change from 12 percent to 16 percent in 2020; this is reflected in the graph."

5.1 Please revise the graph in Figure A1-1 to show net O&M based on a capitalized overhead rate of 12 percent.

Response:

Below is the graph in Figure A1-1 revised to show FEI net O&M in real dollars based on a capitalized overhead rate of 12 percent for the 2019 Base (2019 B).



5.2 Please revise the graphs in Figures A1-1 and A1-2 to show FEI's and FBC's actual gross O&M in real dollars from 2013 to 2019 Base.

Response:

Below are the revised graphs showing actual gross O&M in real dollars from 2013 to 2019 Base.

Figure 1: FEI Actual Gross O&M in Real Dollars from 2013 to 2019 Base

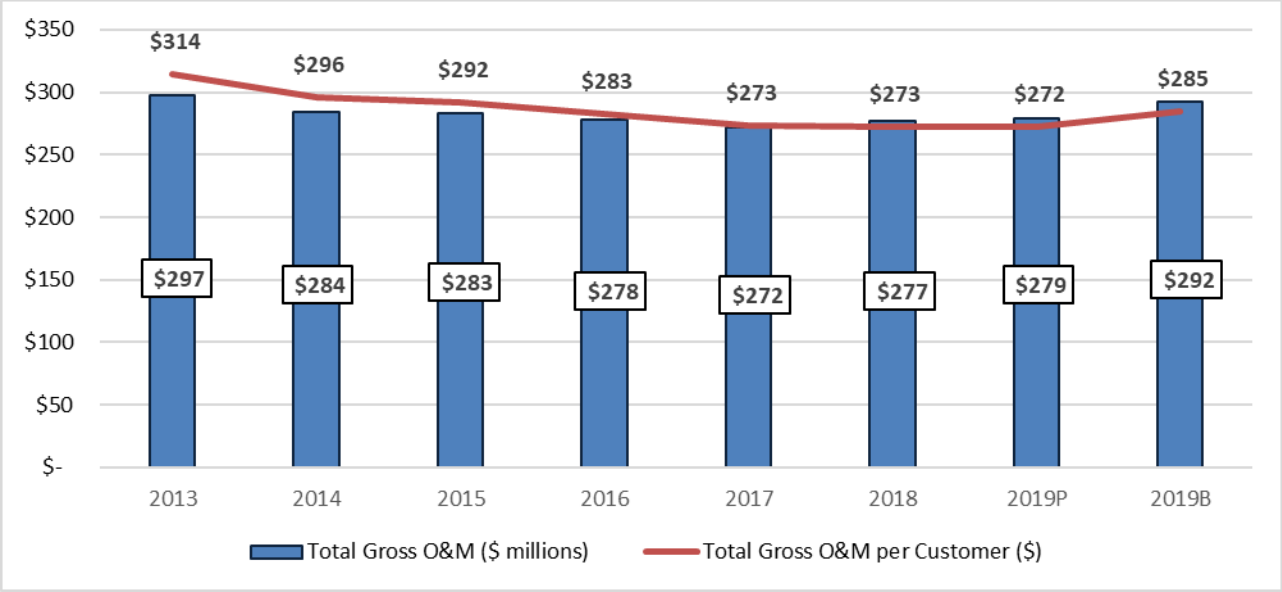
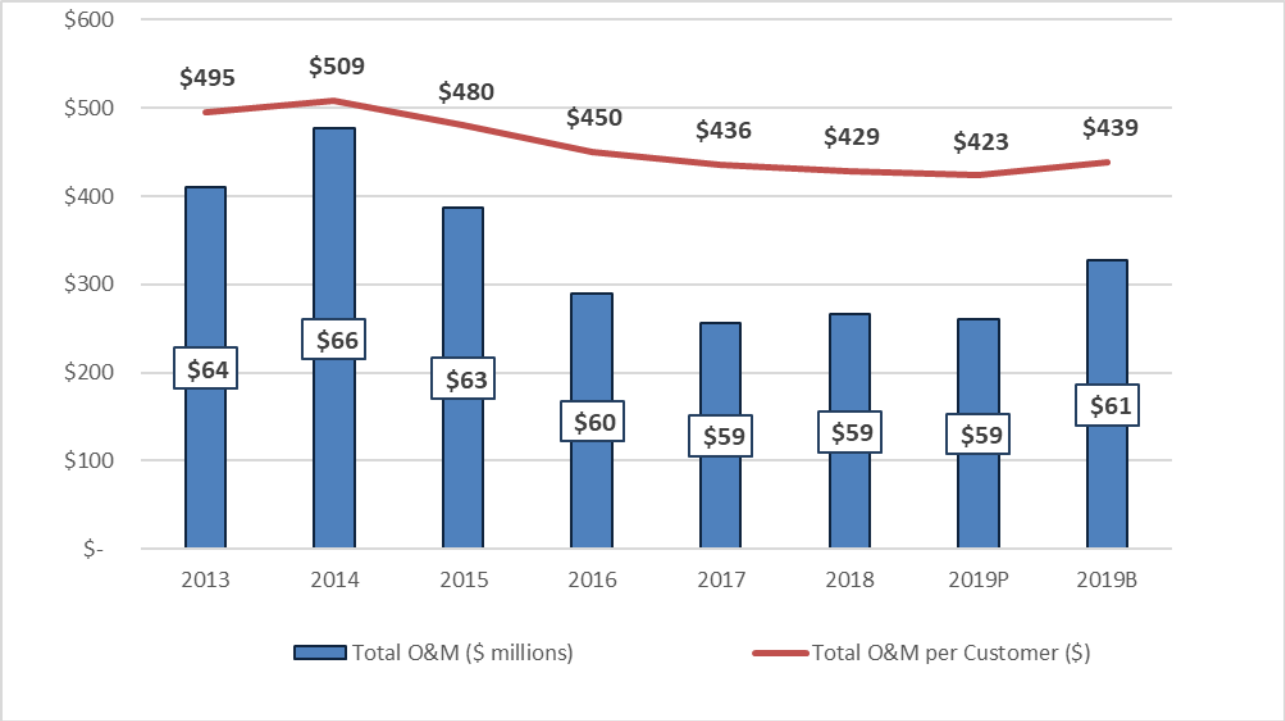


Figure 2: FBC Actual Gross O&M in Real Dollars from 2013 to 2019 Base



6.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.3.1, pp. B-31, B-33; FEI Annual Review for 2019 Delivery Rates proceeding, Exhibit B-2, p. 5

Formula O&M Savings

FortisBC provides the following table on page B-31 of the Application, which shows the "Savings related to 1.10% PIF" in column e.

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**

On page 5 of the FEI Annual Review for 2019 Delivery Rates (2019 Annual Review) application, FEI provides Table 1-2 which shows the formula O&M savings for each year of the Current PBR Plan and the cumulative savings to date.

FEI further states the following on page 5 of the 2019 Annual Review application:

> The table also shows the embedded Productivity Improvement Factor (PIF) savings for the same years. The table shows that in addition to the cumulative formula O&M savings of approximately $42.8 million to the end of 2018 which are shared with customers, the cumulative PIF savings to the benefit of customers total to approximately $12.7 million.

Table 1-2 on page 5 of the FEI 2019 Annual Review application is provided as follows:

Table 1-2: Formula O&M Savings 2014 to 2018 ($ millions)

		Actual	Formula	Variance	1.1% PIF
	2014	$ 191.0	$ 198.5	$ 7.5	$ 2.2
	2015	$ 225.4	$ 235.6	$ 10.2	$ 2.6
	2016	$ 225.9	$ 238.1	$ 12.1	$ 2.6
	2017	$ 232.5	$ 240.4	$ 7.9	$ 2.6
*	2018	$ 238.6	$ 243.6	$ 5.0	$ 2.7
	Cumulative Savings			$ 42.8	$ 12.7

* 2018 is projected.

6.1 Please explain why there is a difference in the calculation of the annual PIF savings between Table 1-2 in the FEI 2019 Annual Review application and Table B2-2 in the Application.

Response:

When calculating the Productivity Improvement Factor (PIF) savings for FEI's and FBC's Annual Reviews for 2019 Rates Applications, FortisBC did not consider the cumulative effect of the PIF over the term of the PBR Plans. As shown in Table 1-2 from FEI's Annual Review for 2019 Rates Application reproduced in the preamble above, FEI calculated the PIF savings as an annual amount that did not carry forward to any future years of the term of the PBR Plan.

In the course of developing the Application, FortisBC determined that the cumulative effects of the PIF should be quantified and presented as savings over the term of the PBR Plans. The PIF has a cumulative effect because, in each year of the PBR Plan, the PIF savings from the prior year are carried forward into Base O&M, and the PIF is applied again in that year to further reduce Base O&M. Thus, the PIF savings in 2014 is realized not only in 2014 O&M, but also in each future year of the PBR Plans, from 2015 through 2019. For example, in the case of FEI, the 2014 PIF savings of $2.2 million[6] results in a cumulative savings of $13.2 million over the term of the PBR Plan because the same cumulative effect occurs for PIF savings in years 2015 through 2019 of the PBR. This cumulative effect is reflected in the PIF savings in Table B2-2 of the Application.

[6] 2019 Annual Review, Table 1-2, 2014, 1.1% PIF.

On page B-31 of the Application, with regard to FEI, FortisBC states, "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)."

On page B-33 of the Application, with regard to FBC, FortisBC states, "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…Total O&M per customer has decreased by more than 14 percent over the period."

6.2 Please explain, and provide supporting calculations where possible, how much of the decrease in actual Formula O&M per customer and Total O&M per Customer is attributable to FEI's and FBC's annual customer and load growth.

Response:

Since the unit costs are determined on a per customer basis, and not per unit of energy delivered, none of the changes relate directly to load growth.

Please refer to the response to BCUC IR 1.17.7, which discusses in detail the relationship between customers and O&M expense and explains that FortisBC is unable to specifically identify the O&M expenses which are impacted by changes in average customers.

6.3 In consideration of the annual O&M savings achieved by each of FEI and FBC above the formula, please discuss in detail whether FortisBC considers both the inclusion of, and the quantum of, the productivity factor to have been a reasonable and successful component of each of FEI and FBC's Current PBR Plans.

Response:

As explained in Section B2.3.1 of the Application, both FEI and FBC achieved significant O&M savings during their PBR terms. However, the incentives to achieve these savings are not derived from the inclusion or quantum of the productivity factor. Rather, they are derived from the decoupling between revenues and costs during the Plans' terms, the length of the rate period and the amount of the costs that are subject to an incentive framework. The incentives are also impacted by the inclusion of an earnings-sharing mechanism. The X-Factor does ensure that part of the "expected" industry productivity growth during the Plans' terms is passed

to customers regardless of the actual performance of the Utilities. However, in the case of FEI's and FBC's performance, and considering that the achieved savings amounts for both Companies were higher than the PIF savings, customers would have received 50 percent of those O&M savings during the Plans' term (via the ESM which shares savings equally with customers) regardless of the inclusion of the X-Factor. At paragraph 166 of Decision 20414-D01-2016, dated December 16, 2016,[7] the AUC explained this issue as follows:

> Experts for the distribution utilities pointed out that incentives are not affected by the choice of a particular value of the X factor, whether it is negative, zero or positive, except to the extent that the value selected may affect availability of incremental capital funding through particular capital tracker mechanisms. Rather, these incentives derive from the decoupling between revenues and costs that is explicit in a PBR plan. The Commission agrees. However, the Commission also is aware that indexing prices or revenues by I-X is based on the idea that part of the expected efficiency gains from PBR are passed on to consumers during the PBR plan term through the X factor, regardless of the actual performance of the distribution utilities. The appeal of this approach to consumers is obviously decreased when there are efficiency losses, and the value of X is negative.

6.3.1 As part of the above response, please discuss whether FEI's level of O&M savings achieved above the formula could be an indication that the productivity factor may have been too low.

Response:

The achieved O&M savings and the declining O&M unit costs, both on a standalone and on a relative basis, are an indication of effective management and reflect FEI's efforts to find new efficiencies and improve its operations during the PBR term.

Further, the X-Factor value that was set for FEI in the 2014 PBR Decision to reflect the expected industry productivity growth is higher than what has been approved for FEI's Canadian peers. Therefore, the productivity factor was not too low.

[7] Online: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20414-D01-2016%20(Errata).pdf

7.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1-1, Appendix B6, p. 3; FEI Annual Review for 2018 Delivery Rates proceeding, Exhibit B-3, BCUC IR 3.3

FEI Report on Initiatives During the Current PBR Plan Term

In Appendix B6 to the Application, Table A:B6-4, FEI provides information on the "Review of Technical and Infrastructure Support Provider" efficiency initiative.

In response to BCUC IR 3.3 in the FEI Annual Review for 2018 Delivery Rates (2018 Annual Review) proceeding, FEI stated: "The existing contract with Compugen ends December 31, 2019, with the option, at the discretion of FEI, to extend for two years."

7.1 Please provide the status of FEI's existing contract with Compugen and the impact from an O&M perspective that the expiry of the existing contract may have on costs during the proposed MRP term.

Response:

FEI has been satisfied with the services managed by Compugen over the past five years. Negotiations for another five-year term are nearing completion. The new contract is in line with the previous contract in regards to costs and services, and is not expected to have an impact on costs during the proposed MRP term.

In Appendix B6 to the Application, TableA: B6-4, FEI states the following regarding the contract with Compugen: "For each permanent reduction in Compugen's costs to support FEI, the vendor and FEI share in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies."

7.2 Please explain if any permanent reductions in Compugen's costs have been achieved during the existing contract term. If yes, please provide the amount of the savings and the allocation of the savings between Compugen and FEI.

Response:

There have been no permanent reductions in the base cost of services provided by Compugen that would have been subject to sharing between Compugen and FEI. There have also not been any increases to the base cost of services provided by Compugen in the first five years of the contract.

8.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Sections B2.3.2.1.1, C1.4.3, C3.3.1, pp. B-34 – B-35, C-10, C-58; Exhibit

B-1-1, Appendix B8-1

FEI Growth Capital

Table B2-4 on page B-34 of the Application shows the FEI growth capital variances from 2014 to 2019.

On pages B-34 and B-35 of the Application, FortisBC describes the two main factors which contributed to the annual variances in growth capital, including changes to the mix of customer type and location of new attachments such as the increase in growth in industrial mains and the increase in service line additions activity on Vancouver Island, which led to an increase in overall unit costs.

FortisBC further states on page B-35 of the Application: "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."

8.1 Please recreate Table B2-4 under the following scenarios. Please show all supporting calculations:

- The growth factor approved for FEI in the Current PBR Plan was based on forecast service line additions (but the 0.5 multiplier was still applied);
- The growth factor approved for FEI in the Current PBR Plan was based on historical service line additions (as approved in the Current PBR Plan) but the growth factor was not reduced by 0.5; and
- The growth factor was based on forecast service line additions and there was no 0.5 multiplier applied to the growth factor.

Response:

The Current PBR Plan required FEI to use a lagging growth factor to determine Growth capital; consequently, gross service line addition forecasts were not produced. Instead, FEI has used the actual service line additions in lieu of a forecast. This is also a better comparison because, under FEI's proposed mechanism, FEI will true up the forecast customer additions to actual for purposes of rate setting.

Table 1: Forecast of Growth Factor with 50% multiplier included

Year	Actual	Formula	Variance
2014	24.231	26.009	1.778
2015	45.776	36.760	(9.016)
2016	47.500	36.827	(10.673)
2017	59.542	42.221	(17.321)
2018	82.884	43.474	(39.410)
2019P	63.328	40.257	(23.071)
Total	323.262	225.548	(97.713)

Table 2: Lagging Growth Factor with 50% multiplier excluded

Year	Actual	Formula	Variance
2014	24.231	21.326	(2.905)
2015	45.776	26.651	(19.125)
2016	47.500	35.478	(12.022)
2017	59.542	35.822	(23.720)
2018	82.884	44.183	(38.701)
2019	63.328	49.825	(13.504)
Total	323.262	213.285	(109.977)

Table 3: Forecast Growth Factor with 50% multiplier excluded

Year	Actual	Formula	Variance
2014	24.231	30.389	6.158
2015	45.776	43.712	(2.064)
2016	47.500	43.665	(3.835)
2017	59.542	56.319	(3.223)
2018	82.884	59.322	(23.562)
2019	63.328	49.706	(13.622)
Total	323.262	283.112	(40.149)

As can be seen in the last table, of the three scenarios, the ones that excludes the 50 percent multiplier and uses a forecast growth factor would have resulted in the lowest variance. For a review of other factors that led to the variance between the actual and formula amounts please refer to Appendix B8-1 of the Application.

On page B-35 of the Application, FortisBC states the following:

> 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 lower at 0.79.

8.2 Please explain whether the calculation of the correlation coefficient takes into account the increases in growth capital costs due to the factors described in the above preamble (e.g. changes to the mix of customer type and location, etc.).

Response:

The Pearson correlation coefficient is used to quantify the direction and strength of the linear association between two variables. The correlation analysis, however, does not necessarily indicate causal relationship and cannot be used to distinguish between the impacts of various factors (e.g., changes to the mix of customer and location) on the final correlation coefficient value.

The correlation analysis in the Application shows the strong linear relationship between actual Growth capital and the proposed growth factor, which negates the non-linearity argument that was used in the BCUC's 2014 PBR Decision to justify the 50 percent reduction of the growth factors. The correlation analysis does not distinguish the impact of various factors on the Growth capital costs.

8.3 Please provide the supporting calculations for the correlation coefficients of 0.95 and 0.79 and explain all inputs and assumptions.

Response:

The tables below provide the supporting data for the correlation coefficient calculations. To compute the correlation coefficient, FEI used MS Excel's CORREL function. The correlation function was run twice: once for new attachments vs. formula Growth capital amounts and once for new attachments vs. actual Growth capital amounts. With the exception of using projected 2019 numbers, no other assumptions were used.

Table 1: New Attachments vs. Formula Growth Capital Amounts

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient
New attachments	13,583	16,213	17,261	20,825	2,2439	18,540	0.79
Formula Growth Capital ($ millions)	21.48	28.48	33.26	33.48	37.48	40.14	

Table 2: New Attachments vs. Actual Growth Capital Amounts

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient
New attachments	13,583	16,213	17,261	20,825	22,439	18,540	0.95
Actual Growth Capital ($ millions)	24.23	45.78	47.50	59.54	82.88	63.33	

8.4 Please calculate the correlation coefficients for actual and formula O&M and explain all inputs and assumptions.

Response:

FEI presumes that the question asks for the correlation of the actual and formula O&M against the O&M formula cost driver (average number of customers). With this assumption, the correlation coefficient numbers and related input data are provided below. The results indicate a strong linear association between the cost driver and both actual and formula O&M.

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient
Avg number of customers	959,196	968,766	983,807	997,380	1,016,353	1,024,962	0.95
Actual formula O&M ($ millions)	223,967	225,380	225,925	232,503	238,693	246,939	

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient

Avg number of customers	959,196	968,766	983,807	997,380	1,016,353	1,024,962	0.97
Formula O&M ($ millions)	233,712	235,619	238,068	240,412	243,585	248,939	

On page C-10 of the Application, FortisBC states that it 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."

8.5 Please provide the correlation coefficient for growth capital during FEI's 2004-2009 PBR term. Please provide all supporting calculations and explain all inputs and assumptions.

Response:

FEI is not able to provide the Growth capital and gross customer additions correlation for 2004-2005 as the data is not readily accessible in the format required for this analysis. However, FEI is able to provide the requested data for 2006 to 2009, and the average number of customers and O&M correlation from 2004 to 2009 as requested in BCUC IR 1.8.6. The data for O&M is from FEI's Annual Reports and is readily available in a format sufficient to provide the correlation analysis requested.

FEI

$000	**2004 Actual**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**Correlation**
Growth Capital							
New Customer Mains			8,147	8,106	10,991	6,140	
New Customer Services			16,404	17,079	17,984	12,094	
New Customer Meters			4,269	3,720	3,314	1,503	
Total Growth Capital			28,820	28,905	32,289	19,737	**0.90**
Gross Customer Adds			13,397	15,485	14,543	9,805	
Average Number of Customers	779,779	791,593	802,743	816,427	825,696	832,751	**0.92**
O&M	143,926	142,710	150,223	149,564	156,208	162,026	

8.6 Please provide the correlation coefficient for O&M during FEI's 2004-2009 PBR term. Please provide all supporting calculations and explain all inputs and assumptions.

Response:

Please refer to the response to BCUC IR 1.8.5.

Table A:B8-1-1 on page 3 of Appendix B8-1 shows the approved growth capital for years 2014 through 2018 broken into the three main components of growth capital – Mains, Meters and Service Line Additions (SLAs).

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

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

Table A:B8-1-2 on page 4 of Appendix B8-1 shows the following:

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

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

On page C-58 of the Application, FEI provides the following breakdown of actual growth capital expenditures during the Current PBR Plan term:

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

8.7 Please explain why the annual actual New Customer Services amounts in Table C3-1 of the Application do not agree with the annual actual SLA amounts in Table A:B8-1-2 of Appendix B8-1 and, if appropriate, please provide updated tables.

Response:

In the course of responding to this information request, FEI noted an error in Table A:B8-1-2 of Appendix B8-1 of the Application. The actual capital expenditures in the 2015-2018 period, in accordance with Table C3-1 on page C-58 of the Application, should be:

- $30.064 million in 2015;
- $31.246 million in 2016;
- $39.149 million in 2017; and
- $53.993 million in 2018.

A corrected version of Table A:B8-1-2 is provided below and will be included in an Errata to be filed in the near future.

The remaining difference in actual New Customer Services amounts for 2014 in Table A:B8-1-2 and Table C3-1 of the Application is due to the inclusion of FEVI and FEW capital expenditures in Table C3-1 for comparative purposes across the time frame shown. Since Appendix B8 is an evaluation of capital spending across the Current PBR Plan term, it is correct to not include FEVI and FEW in 2014 since they were not under PBR in that year.

	Approved			*Actual*			*Variance*	
Year	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**Capital**
2014 A	7,934	$ 1,624	$ 12,886	8,473	$ 2,096	$ 17,762	539	$ 4,876
2015 A	9,586	$ 1,825	$ 17,495	12,392	$ 2,426	$ 30,064	2,806	$ 12,569
2016 A	11,143	$ 1,834	$ 20,432	12,288	$ 2,543	$ 31,246	1,145	$ 10,814
2017 A	11,180	$ 1,840	$ 20,565	15,856	$ 2,469	$ 39,149	4,676	$ 18,584
2018 A	12,443	$ 1,864	$ 23,192	16,606	$ 3,251	$ 53,993	4,163	$ 30,800
Cumulative	**52,286**	**$ 1,809**	**$ 94,572**	**65,615**	**$ 2,625**	**$ 172,215**	**13,329**	**$ 77,643**

Table A:B8-1-3 on page 6 of Appendix B8-1 shows the following:

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

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

8.8 Please explain why the annual actual New Customer Mains amounts in Table C3-1 of the Application do not agree with the annual actual New Customer Mains amounts in Table A:B8-1-3 of Appendix B8-1 and, if appropriate, please provide updated tables.

Response:

The annual actual New Customer Mains amounts in Table C3-1 of the Application do not agree with the annual actual New Customer Mains amounts in Table A:B-1-3 of Appendix B8-1 due to Pension and OPEB expense. Both the actual and allowed New Customer Mains expenditures in Table A:B8-1-3 include Pension and OPEB adjustments whereas Table C3-1 of the Application exclude Pension & OPEB.

Another difference between Table C3-1 and Table A:B8-1-3 is related to the 2014 year. Table A:B8-1-3 includes only the actual and allowed new customer mains expenditures related to FEI for the purposes of comparing to formulaic Growth capital, while Table C3-1 of the Application includes FEVI and FEW to allow a consistent comparison of capital expenditures across the time frame shown. Since Appendix B8 is an evaluation of capital spending across the Current

PBR Plan term, it is correct to not include FEVI and FEW in 2014 since they were not under PBR in that year.

8.8.1 Please also explain why the Allowed New Customer Mains amounts in Table A:B8-1-3 of Appendix B8-1 do not agree with Approved Growth Capital for Mains amounts in Table A:B8-1-1 of Appendix B8-1.

Response:

Please refer to the response to BCUC IR 1.8.8.

Table A:B8-1-2 on page 4 of Appendix B8-1 shows the formula and actual capital amounts for SLAs for years 2014 through 2018 and separately identifies the dollar variances attributable to the number of SLAs and the dollar variances attributable to the unit cost of SLAs.

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

8.9 Please confirm, or explain otherwise, that the primary contributor to the variance in SLA growth capital is the variance in the unit cost of SLAs (i.e. $/SLA).

Response:

Confirmed. Please refer to Appendix B8-1, Section 2.1, FEI Capital Directives for a detailed explanation of the factors contributing to both the activity and cost variances as outlined in Table A:B8-1-2 above.

8.10 Please explain in detail why the $/SLA variance in 2018 (i.e. $1,419/SLA) is significantly higher than the previous four years' variances.

Response:

Please refer to the response to BCUC IR 1.8.7 for a corrected Table A:B8-1-2 from Appendix B8-1, the relevant portion of which is reproduced below. As seen below, the $/SLA variance in 2018 was $1,388/SLA.

	Activity Variance (Approved)			*Cost Variance*			*Variance*
Year	SLAs Variance	Approved $/SLA	Capital Variance from # SLAs	Actual SLAs	$/SLA Variance	Capital Variance from Cost per SLA	Capital
2014 A	539	$ 1,624	$ 875	8,473	$ 472	$ 4,001	$ 4,876
2015 A	2,806	$ 1,825	$ 5,122	12,392	$ 601	$ 7,447	$ 12,569
2016 A	1,145	$ 1,834	$ 2,099	12,288	$ 709	$ 8,715	$ 10,814
2017 A	4,676	$ 1,840	$ 8,603	15,856	$ 630	$ 9,982	$ 18,584
2018 A	4,163	$ 1,864	$ 7,759	16,606	$ 1,388	$ 23,041	$ 30,800
Cumulative	**13,329**		**$ 24,458**	**65,615**		**$ 53,185**	**$ 77,643**

FEI experienced cost increases in several areas that contributed to the overall service line cost variance in 2018, which are discussed below.

Contractor cost increases account for approximately 75 percent of the total cost variance in 2018. The main factors that contributed to the 2018 contractor cost variance are outlined as follows:

- The percentage of services over 15 metres in length increased indicating that the average service length installed was substantially longer than in previous years.
- Hydrovac costs increased substantially in 2018 as compared to prior years due to increased work in close proximity to third party utilities.
- Paving and traffic control costs were higher due to municipal requirements and increased proportion of conversion services.

In addition to higher contractor costs, FEI also saw an increase in internal crew charges as a result of mobilizing out of town crews to the Lower Mainland to deal with high volumes of Growth capital work. The mobilization of both internal crews and contractors to complete Growth capital work resulted in cost increases in labour and non-labour expenditures. These costs were necessary in order to maintain service levels and customer connections due to the record level of gross customer and service line additions activity experienced in 2018.

Management costs due to the increased oversight on mains and services contractors and the effort to refresh the contract for the competitive bid process also contributed to the total cost variance in 2018.

Another factor contributing to the $/SLA cost variance in 2018 is a result of muster kit material charges for services to better reflect the actual cost for the materials used in an average service installation, which were effective March 2018. Please refer to the response to BCUC IR 1.42.1.1 for a detailed breakdown of costs. The total impact for the incremental muster kit price change and material allocation on New Customer Mains and Services is approximately $0.3 million in 2018.

Finally, as discussed in Exhibit B-1-1, Appendix B8-1, FEI Capital Directives, the SLA activity on Vancouver Island was the highest in 2018 compared to prior years of the Current PBR Plan. This continued increase of activity on Vancouver Island, where the cost per SLA is amongst the highest, exacerbated the total service line cost variance.

On page 5 of Appendix B8-1, FEI describes the following four primary factors that have changed since the base capital per SLA amounts were developed and that are contributing to the cost per service line variances:

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

8.11 Please estimate in percentage terms the amount that each of the above factors has contributed to the cost per SLA variances.

Response:

It is difficult to provide a percentage breakdown for each of the above four factors that contributed to the cost per SLA variance (as expenditures associated with each factor cannot always be isolated). FEI can confirm however, that, of the four factors identified as contributing to the Growth Capital cost variance for SLAs, an increase in the number of customer

attachments per service line addition and an increase in SLA activity on Vancouver Island[8] and pricing have had the largest impact on the cost per SLA variance. These contributing factors were described on page 5 of Appendix B8-1, FEI Capital Directives, in the Application.

8.12 Please provide a breakdown of Table A:B8-1-2 according to SLA activity in Vancouver Island and all other regions.

Response:

A breakdown of Table A:B8-1-2 that shows Vancouver Island and all other regions is provided below.

		Approved								
Line No.	**Year**	**SLAs - other**	**SLAs - VI**	**Total**	**$/SLA - other**	**$/SLA - VI**	**Capital - other**	**Capital - VI**	**Total**
1	2014 A	7,934		7,934	$ 1,624		$ 12,886		$ 12,886
2	2015 A	7,537	2,049	9,586	$ 1,612	$ 2,609	$ 12,150	$ 5,345	$ 17,495
3	2016 A	8,749	2,394	11,143	$ 1,622	$ 2,608	$ 14,189	$ 6,243	$ 20,432
4	2017 A	8,771	2,409	11,180	$ 1,628	$ 2,608	$ 14,282	$ 6,283	$ 20,565
5	2018 A	9,746	2,697	12,443	$ 1,658	$ 2,609	$ 16,156	$ 7,036	$ 23,192
6	**Cumulative**	**42,737**	**9,549**	**52,286**	**$ 1,630**	**$ 2,608**	**$ 69,665**	**$ 24,907**	**$ 94,572**
7									
8		*Actual*							
9	**Year**	**SLAs - other**	**SLAs - VI**	**Total**	**$/SLA - other**	**$/SLA - VI**	**Capital - other**	**Capital - VI**	**Total**
10	2014 A	8,473		8,473	$ 2,096		$ 17,762		$ 17,762
11	2015 A	9,179	3,213	12,392	$ 2,312	$ 2,752	$ 21,221	$ 8,843	$ 30,064
12	2016 A	8,695	3,593	12,288	$ 2,601	$ 2,402	$ 22,614	$ 8,632	$ 31,246
13	2017 A	11,377	4,479	15,856	$ 2,315	$ 2,861	$ 26,336	$ 12,813	$ 39,149
14	2018 A	10,854	5,752	16,606	$ 3,363	$ 3,041	$ 36,504	$ 17,489	$ 53,993
15	**Cumulative**	**48,578**	**17,037**	**65,615**	**$ 2,562**	**$ 2,804**	**$ 124,437**	**$ 47,777**	**$ 172,214**
16									

17		*Activity Variance (Approved)*			*Cost Variance*			*Variance*
18	**Year**	**SLAs variance**	**Approved $/SLA - other**	**Capital Variance from # SLAs -**	**Actual SLAs**	**$/SLA Variance**	**Capital Variance from Cost per SLA**	**Capital**
19	2014 A	539	$ 1,624	$ 875	8,473	$ 472	$ 4,001	$ 4,876
20	2015 A	2,806	$ 1,825	$ 5,122	12,392	$ 601	$ 7,447	$ 12,569
21	2016 A	1,145	$ 1,834	$ 2,099	12,288	$ 709	$ 8,715	$ 10,814
22	2017 A	4,676	$ 1,840	$ 8,603	15,856	$ 629	$ 9,981	$ 18,584
23	2018 A	4,163	$ 1,864	$ 7,759	16,606	$ 1,388	$ 23,041	$ 30,800
24	**Cumulative**	**13,329**		**$ 24,458**	**65,615**		**53,185**	**$ 77,643**

[8] SLA's on Vancouver Island have increased both in magnitude and in proportion to overall SLA's over the PBR term. SLA unit costs on Vancouver Island have also been traditionally higher relative to overall SLA's unit costs due to terrain conditions and have been generally higher over the MRP term as well. Accordingly, Vancouver Island SLA's contribute to significant price and volume variances in overall Growth capital.

8.13 Please explain how FEI has addressed each of these factors in its development of the Base Growth Capital for the proposed MRP term.

Response:

The following highlights how FEI has addressed Growth capital for the proposed MRP by incorporating the four key issues that were encountered in the Current PBR Plan term as it relates to New Customer Mains and Services.

1. Gross Customer Additions: FEI is proposing to use gross customer additions instead of service line additions for its Growth capital formula. This approach captures the number of customers attaching to FEI's natural gas system rather than the number of service line risers installed which can vary depending on the number of customers serviced by the service line installation. The use of gross customer additions to determine FEI's Growth capital formula should provide for a better reflection of costs as service line riser costs to multi-family developments are higher than for single family homes because of the need for multiple meters and larger headers. This approach also provides for a better correlation to new meter expenditures.

2. Forecast growth factor: FEI is proposing to use a forecast growth factor as opposed to a 50 percent lagged growth factor. When preparing this response FEI identified an omission in Table C1-2 from the Application. The table omitted the additional costs that the amalgamation of FEVI and FEW caused on the unit cost per SLA. When including those additional costs, the Growth capital recalculated using Actual Additions increases. FEI has provided a revised Table C1-2 in the response to CEC IR 1.11.1 which shows that Growth capital has been underfunded by approximately $76 million to the end of 2018 (not $35 million as previously shown). By using a forecast of gross customer additions, the Growth capital provided by formula will be indicative of the market trends for new construction and conversion activity and hence customer attachments.

3. Elimination of 50 percent Factor – FEI is proposing to discontinue the 50 percent reduction to the growth factor for Growth capital for the MRP term. In the 2014 PBR Decisions, the growth factor was reduced by 50 percent. This reduction to the growth factor is one of the reasons for persistent underfunding of formulaic Growth capital amounts during the Current PBR Plan. As discussed in Section B2.3.2.1.1 of the Application, FEI determined that there is a high correlation between the number of new attachments and actual formula-related Growth capital costs which supports FEI's proposal to not incorporate the 50 percent adjustment factor in the proposed MRP.

4. Three year historical average – FEI is proposing to use the recent 3-year historical average as the basis for developing its 2019 base. Using 2016 through 2018 actual Growth capital expenditures to determine the Growth capital base reflects recent experience and is representative of FEI's current level of capital investment required to provide service to new customers. Specifically, the 2016 through 2018 actual expenditures for New Customer Services and New Customer Mains incorporate the unit cost pressures that have been recently experienced related to local government requirements, increased service activities on Vancouver Island, unfavorable CAD/USD exchange rates and growth in larger industrial main additions.

   Regarding activities on Vancouver Island, the amalgamation of FEI, FEVI and FEW in 2015 resulted in a three-year phase-in to a lower common rate. As of 2018, all FEI customers (except Fort Nelson region customers) pay the same rates across all rate schedules. At the time that FEI was phasing in FEVI and FEW to lower common rates, new attachments in those regions increased materially. FEI expects the level of new customer attachments in those regions to remain strong. The actual Growth capital that FEI incurred 2016 through 2018 is reflective of the strong level of new attachments in those regions and is therefore a reasonable growth capital base for the upcoming MRP.

   The three-year recent average, adjusted to incorporate construction price increases and muster kit and material allocation impacts, will allow for a more appropriate starting point for Growth capital unit costs for the proposed MRP.

Given the amendments above, FEI does not expect the factors above to be a significant driver of variances for the upcoming MRP term. This is because the Base should now reflect the recent changes that were listed. Specifically:

1. FEI's proposal moves away from the more variable service line addition method;
2. The initial impact of the inclusion of Vancouver Island in the base is fully reflected;
3. FEI does not have any indication that CDN/USD exchange rates will deteriorate significantly during the upcoming MRP term;
4. To the extent there are changes to local government legislation that drive material cost changes, FEI will consider whether these factors need to be brought forward for discussion at an Annual Review.

Further, to mitigate unfavourable USD exchange rates, FEI is currently working to increase the number of approved vendors and products for inventoried materials, and FEI continues to work closely with local governments to ensure that reasonable requirements are met with efficiency and to ensure that all requirements are compliant with the local operating agreements.

In consideration of FEI's operating environment currently and over the next five years (as described on pages C-61 and C-62 of the Application), other factors that FEI anticipates impacting unit costs are (i) contractor price increases; (ii) variations in regional growth activity; (iii) changing requirements for field quality assurance; and (iv) increased levels of testing. A best estimate of the impact of these factors has been included in the proposed unit cost for Growth capital.

8.14 Please discuss which of the above four factors, if any, might contribute to variances in the cost per SLA during the proposed MRP term.

Response:

Please refer to the response to BCUC IR.1.8.13.

8.14.1 As part of the above response, please discuss FEI's mitigation strategies for unfavourable USD exchange rates and local Government requirements during the Proposed MRP period.

Response:

Please refer to the response to BCUC IR.1.8.13.

8.15 In consideration of FEI's operating environment currently and over the next five years, what new factors might impact the cost per SLA and thus lead to variances in the cost per SLA during the proposed MRP term? As part of this explanation, please discuss how FEI has, or could, mitigate these factors.

Response:

Please refer to the response to BCUC IR.1.8.13.

FEI states on page 7 of Appendix B8-1 that the variance in costs for customer mains is driven partly by the growth in large industrial mains but that it does not have a capital formula specific to larger industrial mains so it is not able to directly quantify the amount of the variance due to this factor.

8.16 Please provide the information for customer mains in a format similar to Table A:B8-1-2 (i.e. Service Line Addition Capital Variances) in order to distinguish between the variances attributable to the unit cost of mains and the variances attributable to the number of mains.

Response:

Please see the table below for New Customer Mains showing cost and activity variances similar to Table A:B8-1-2. As can be seen from this table, approximately half of the mains cost variance is due to the number of SLAs and the balance remaining is from the mains unit cost per SLA. While the cost per SLA has increased over the Current PBR Plan term, there has also been an increase in the customers attached per SLA during the same period. FEI has acknowledged that the number of service line additions is not an appropriate activity driver for Growth capital due to the increase in customer attachments per service line (which results in higher cost per service line addition) in the Current PBR Plan. As such, FEI is proposing to use gross customer additions, instead of service line additions, in its Growth capital formula for the MRP term.

		Approved			*Actual*			*Variance*	
Line No.	**Year**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**Capital**
1	2014 A	7,934	$ 818	$ 6,490	8,473	$ 618	$ 5,240	539	$ (1,250)
2	2015 A	9,586	$ 905	$ 8,672	12,392	$ 1,136	$ 14,082	2,806	$ 5,410
3	2016 A	11,143	$ 909	$ 10,129	12,288	$ 1,066	$ 13,103	1,145	$ 2,974
4	2017 A	11,180	$ 912	$ 10,194	15,856	$ 1,050	$ 16,654	4,676	$ 6,459
5	2018 A	12,443	$ 907	$ 11,284	16,606	$ 1,489	$ 24,729	4,163	$ 13,445
6	**Cumulative**	**52,286**	**$ 894**	**$ 46,770**	**65,615**	**$ 1,125**	**$ 73,807**	**13,329**	**$ 27,038**
7									
8		***Activity Variance (Approved)***			***Cost Variance***				***Variance***
9	**Year**	**SLAs Variance**	**Approved $/SLA**	**Capital Variance from # SLAs**	**Actual SLAs**	**$/SLA Variance**	**Capital Variance from Cost per SLA**		**Capital**
10	2014 A	539	$ 818	$ 441	8,473	$ (200)	$ (1,691)		$ (1,250)
11	2015 A	2,806	$ 905	$ 2,539	12,392	$ 232	$ 2,871		$ 5,410
12	2016 A	1,145	$ 909	$ 1,040	12,288	$ 157	$ 1,934		$ 2,974
13	2017 A	4,676	$ 912	$ 4,264	15,856	$ 138	$ 2,195		$ 6,459
14	2018 A	4,163	$ 907	$ 3,775	16,606	$ 582	$ 9,669		$ 13,445
15	**Cumulative**	**13,329**		**$ 12,060**	**65,615**		**$ 14,978**		**$ 27,038**

8.17 Please explain how much of the growth in large industrial mains is attributable to Vancouver Island.

Response:

The following table outlines the percentage breakdown of large industrial mains jobs over $100 thousand by region.

	2014	**2015**	**2016**	**2017**	**2018**
Lower Mainland	25%	47%	29%	57%	33%
Fraser Valley	16%	37%	38%	22%	47%
Interior North	6%	2%	18%	0%	0%
Interior South	0%	3%	0%	5%	10%
Vancouver Island	53%	10%	15%	15%	9%
Total	100%	100%	100%	100%	100%

For growth in large industrial mains jobs (greater than $100 thousand), the majority of the increase has been in the Lower Mainland and Fraser Valley areas during the Current PBR Plan term, while Vancouver Island has experienced a decrease in large customer mains capital expenditures from 2014. New Customer Mains unit costs are typically less correlated with regional impacts than that of New Customer Services unit costs. FEI Mains expenditures are

driven by customer growth, and the type and load requirements for the customer impacts the timing, size and cost of the mains.

8.18 Please explain how FEI has addressed the issues encountered during the Current PBR Plan term related to variances in mains, and in particular the variances attributable to large industrial mains, in its development of the Base Growth Capital for the proposed MRP term.

Response:

Please refer to the response to BCUC IR 1.8.13.

8.18.1 As part of the above response, please explain if FEI considered developing a capital formula specific to larger industrial mains and if so, why this approach was not considered appropriate for the proposed MRP. If FEI did not consider developing a larger industrial main-specific formula, please explain why not.

Response:

In the course of developing the proposed Growth capital formula, FEI considered developing a capital formula specific to mains. During this assessment, it was determined that a single unit cost measurement for all activities in Growth capital (mains, services, meters and distribution system improvements) would be the most appropriate option given the variability of the larger industrial mains year over year and the challenge of generating an accurate forecast for large mains work beyond a year. The single unit cost approach allows for a simpler regulatory process and provides greater opportunity to prudently manage variations in costs between different growth categories (e.g., a large industrial customer that drives main costs outside of threshold could be offset by lower service cost).

8.19 In consideration of FEI's operating environment currently and over the next five years, what new factors might impact the growth and costs of mains and thus

lead to variances between formula and actual costs during the proposed MRP term? As part of this explanation, please discuss how FEI has, or could, mitigate these factors.

Response:

In its response to BCUC IR 1.8.13, FEI noted three new factors which it anticipates will impact costs, including contractor price increases, field quality assurance, and testing. Contractor pricing has the largest impact on costs. In the responses to BCUC IRs 1.42.3 and 1.42.3.1, FEI notes that it will consider the timing of either extending its contracts or competitive bidding based on prevailing market conditions; however, many factors influence contractor pricing.

More generally, FEI has proposed a unit-cost approach to Growth capital that does not include a dead band for the MRP. This places greater incentive on FEI to manage unit costs and identify new strategies to capture efficiencies and manage costs. However, FEI has not identified any specific initiatives at this time.

9.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B.2.3.2.1.2, pp. B-35 – B-36; Exhibit B-1-1, Appendix B8-1, p. 8

FEI Sustainment/Other Capital

On page B-35 of the Application, FEI provides Figure B2-3 which shows the trend in the number of new attachments from 2014 to 2019 compared with the formula generated and actual growth capital amounts.

FEI further states the following on page B-35:

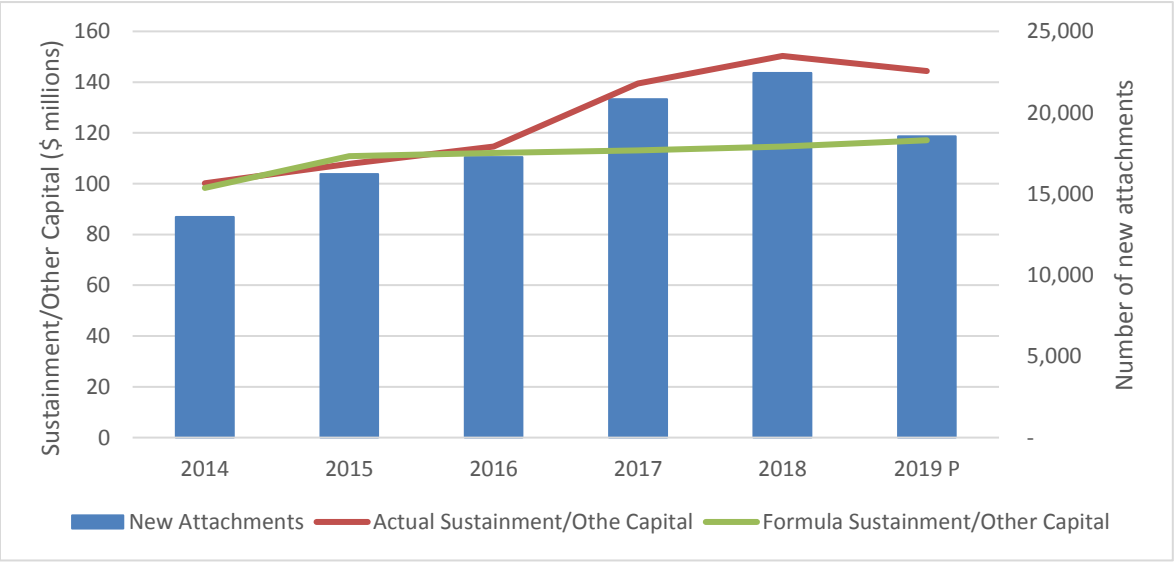
> A simple correlation analysis between the number of new attachments and actual and formula Growth capital amounts indicates that the correlation coefficient between the number of new attachments and actual costs is close to 0.95, while the correlation coefficient between the number of new attachments and the formula-generated Growth capital is lower at 0.79.

9.1 Please provide a correlation analysis similar to Figure B2-3 for FEI's sustainment/other capital to show how the trend in customer additions compares with actual and formula-driven sustainment/other capital during the Current PBR Plan term.

Response:

The requested correlation analysis is provided in the figure below.

Figure 1: FEI Trend in New Attachments Compared with Actual and Formula-driven Sustainment/Other Capital



A simple correlation analysis between the number of new attachments and actual and formula Sustainment and Other capital indicates that the correlation coefficient between the number of new attachments and actual costs is close to 0.92, while the correlation coefficient between the number of new attachments and the formula-generated Sustainment/Other Capital is lower at 0.77.

Table B2-5 on page B-36 of the Application shows FEI's sustainment and other capital variances from 2014 to 2019.

Table A:B8-1-4 on page 8 of Appendix B8-1 provides a breakdown of the sustainment/other capital variances.

9.2 Please explain why the cumulative sustainment/other capital variance of $90.542 million in Table B2-5 does not agree with the cumulative sustainment/other capital variance in Table A:B8-1-4 (i.e. variance of $63.358 million).

Response:

Table A:B8-1-4 contains three errors in the cumulative variance compared to formula. The annual variance amounts are correct. The cumulative figures highlighted below had incorrect cell references. A corrected version of Table A:B8-1-4 is included below and will be included in an Errata to be filed in the near future.

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

Line No.	Description	2014	2015	2016	2017	2018	Forecast 2019	Cumulative
1	PBR Decision reduction to base sustainment capital for Vancouver Island pressure	-	6.351	6.417	6.484	6.567	6.711	32.531
2	PBR Decision growth factor for net customer additions pressure	0.259	0.939	1.586	2.250	3.234	4.233	12.502
3	Regionalization Initiative	1.300	0.100	0.600	-	-		2.000
4	Installation of bypass (Jomar) valves	-	0.050	2.070	2.590	3.400	3.400	11.510
5	Increased in-line inspection activity	1.944	1.295	3.287	1.719	(2.547)	4.087	9.785
6	Unanticipated system improvements and new stations to supply gas to new customers	0.600	2.700	1.764	1.901	3.418	0.323	10.706
7	Whistler IP pipeline					10.273	1.454	11.727
8	Burns Bog stress relief	0.300	1.800	1.000	2.827	-	-	5.927
9	Other contributing factors:							-
10	PBR formula pressures resulting from increase in PIF (1.1% vs. 0.5%)	0.597	0.664	0.669	0.676	0.684	0.693	3.984
11	Prince George #1 lateral erosion	0.150	0.030	0.040	0.682	-	-	0.902
12	Ministry of Transportation and Infrastructure IP relocation		0.050	0.700		-	-	0.750
13	Mission IP seismic upgrade		1.200			-	-	1.200
14	Ashcroft Lateral Pipeline replacement due to flood erosion				1.308	1.269	0.743	3.320
15	Cyber security				0.423	0.500		0.923
16	Operations Fleet Requirements					6.000	1.250	7.250
17	**TOTAL Sustainment / Other Pressures**	5.150	15.180	18.134	20.860	32.798	22.895	115.017
18	**Actual annual and cumulative Sustainment / Other capital expenditures variance compared to formula**	1.825	(3.098)	2.588	26.311	35.732	27.244	90.603

Notes:
1. PBR formula pressures related to reduction to base sustainment capital for Vancouver Island.
2. PBR formula pressures resulting from 50% of net service additions.

The remaining minor variance between $90.603 and $90.542 relates to rounding in Table B2-5. When corrected, the Total Actual amount in Table B2-5 changes from the $756.655 to $756.716 as illustrated below.

Amended 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	756.716	666.113	(90.603)	13.6%

On page B-36 of the Application, FortisBC states that the biggest contributor to the variance in formula versus actual sustainment capital relates to the reduction directed by the BCUC in Order G-106-15 to FortisBC Energy Inc. Vancouver Island (FEVI)'s base sustainment capital of $6.3 million. FortisBC states that "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."

9.3 If the reduction to FEVI's base sustainment capital had not been directed by the BCUC, please discuss whether FEI believes that it would have been able to reasonably manage its sustainment/other capital spending close to the formula amount during the Current PBR Plan term.

Response:

The reduction to FEVI's base sustainment capital resulted in a cumulative reduction of $32.5 million in formula allowed capital over the 2015-2019 period. Although this was the single largest contributor to the variance of Sustainment and Other capital compared to formula, FEI does not believe that it would have been able to manage its Sustainment and Other capital spending even in the absence of this reduction.

The main contributors to the cumulative Sustainment/Other capital expenditures variance compared to formula were:

- PBR decisions:
  - Reduction to FEVI's base sustainment capital - $32.5 million;
  - PBR decision growth factor for net customer additions - $12.5 million; and
  - PBR formula pressures resulting from increase in PIF - $4.0 million.
- Unanticipated expenditures related to higher than expected growth:
  - Unanticipated system improvements and new stations - $10.7 million;
  - Whistler IP pipeline - $11.7 million; and
  - Operations Fleet Requirements - $7.3 million.

Cumulatively, these factors contributed 87 percent of the $90 million variance compared to formula. If it was possible to remove the impacts of these factors from the Current PBR Plan, FEI believes it could have managed its Sustainment and Other capital overall within the 10 percent dead band.

9.3.1 If no, please describe the additional changes which FEI believes would have been required in order to manage its sustainment/other capital spending close to or within the formula amount during the Current PBR Plan term.

Response:

Please refer to the response to BCUC IR 1.9.3.

9.3.2 If the changes identified by FEI were implemented, and in consideration of FEI's planned capital spending over the proposed MRP term, would a formula approach to sustainment/other capital be reasonable during the proposed MRP term? Please discuss the pros and cons of such an approach.

Response:

Even with the identified changes to the formula noted in BCUC IR 1.9.3, FEI does not believe that a formula approach to Sustainment and Other capital would provide a more reasonable approach than its current proposed forecast for the following reasons:

- FEI's evolving operating environment, as described in Section B1.1 on page B-1 of the Application, includes significant changes in public policy and customer expectations that present both a challenge and opportunity for FEI. A formula approach to Sustainment/Other capital that assumes "business as usual" does not provide the flexibility required to address these challenges in the interest of existing customers.
- Additional investment is required in physical assets and information systems to address the changing security landscape and to ensure the safe and reliable operation of an aging asset base. These expenditures are unrelated to the number of customers on the system, which was the basis for the growth factor in the formula for the Current PBR Plans.
- As described in Section B1.6 on page B-22 of the Application, innovation and the adoption of technologies is a key aspect of transitioning to a lower carbon environment. Pursuing innovation provides an opportunity to proactively manage rate impacts while supporting GHG emissions reduction goals and helping customers.

The pros and cons of a formula approach include:

Pros

- A formula approach will improve the regulatory efficiency as it does not involve a detailed review of annual capital expenditures forecasts.
- To the extent that a formula can be tied to customer additions, it ensures that additions to rate base are balanced by increased customer count and system load to mitigate rate increases.

Cons

- A formulaic approach similar to the Current PBR Plan is based on past expenditures and assumes that system needs and market conditions will remain consistent in the future. In contrast, the forecast included in the Application represents FEI's best estimate of the required expenditures to maintain a safe and reliable system based on the economic and operating conditions that the company expects to experience over the term of the MRP. Additionally, the proposal to review and potentially update 2023 and 2024 expenditures during the Annual Review for 2023 Rates accounts for the uncertainties inherent in a 5-year forecast. This process will provide the opportunity for the BCUC and Interveners to review and ask questions about any material changes to the forecast.
- The forecast approach will allow the stakeholders to scrutinize the annual capital forecasts and gain a better understanding of Companies' capital expenditures and capital plans.
- A formula for Sustainment and Other capital tied to net customer additions fails to represent the drivers for changes in expenditure levels. The majority of Sustainment capital is not related to the number of customers, but is driven by asset condition, regulatory requirements, and the ability to operate the system safely and efficiently. FEI has not been able to find a driver that reflects the varied impacts of these items.

Accordingly, FEI has proposed a forecast which it believes more adequately addresses the challenges experienced in the Current PBR, intervener feedback and the capital needs of the utility over the MRP term.

10.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B.2.3.2.2, p. B-37; Appendix B8-3

FBC Capital Expenditures

10.1 Please re-create Table B2-6 on page B-37 of the Application to separately show the 2014-2019 variances in growth capital and the 2014-2019 variances in sustainment/other capital, similar to Tables B2-4 and B2-5 of the Application.

Response:

Under the Current PBR Plan, FBC's formula capital spending is determined at the aggregate level. FBC does not have disaggregated capital spending envelopes or formula calculations. FEI's formula capital spending is determined at the levels of Growth capital and Sustainment/Other capital and is likewise not further disaggregated.

An arbitrary calculation of formulaic capital components reflects neither the determination of FortisBC's PBR formula capital, nor the internal allocations of the capital components. As a result, no meaningful analysis of the variances to such hypothetical formula amounts can be made. FEI's and FBC's actual expenditures from 2014 to 2018 and projected expenditures in 2019 are the only available reference points from these years for reviewing the respective 2020-2024 capital expenditure forecasts.

Notwithstanding this, the table below shows the hypothetical escalation under the PBR Plan of FBC's Growth capital and Other/Sustainment capital categories based on the 2013 approved forecast capital expenditures which formed the basis for the capital expenditures formula. This hypothetical calculation is provided to show the same level of disaggregation as FEI's capital expenditures. Any further disaggregation of formula amounts would be increasingly less meaningful.

	Growth Capital				Sustainment/Other Capital			
	Actual	Formula	Variance	% Variance	Actual	Formula	Variance	% Variance
2014	15.283	17.944	2.661	14.8%	27.382	24.249	(3.133)	12.9%
2015	17.662	18.025	0.363	2.0%	27.128	24.359	(2.769)	11.4%
2016	12.937	18.233	5.296	29.0%	32.901	24.641	(8.260)	33.5%
2017	19.159	18.395	(0.764)	4.2%	39.894	24.859	(15.035)	60.5%
2018	20.634	18.631	(2.003)	10.7%	39.553	25.187	(14.366)	57.0%
2019P	15.051	18.870	3.819	20.2%	41.449	25.992	(15.457)	59.5%

Table A:B8-3-1 on page 2 of Appendix B8-3 shows the annual capital variances for FBC during the Current PBR Plan term, including a cumulative variance of $16.705 million related to "system improvements to accommodate growth".

10.2 Please confirm, or explain otherwise, that spending on system improvements to accommodate growth is part of FBC's growth capital.

Response:

Confirmed.

10.3 Please explain in detail the factors contributing to the variance in spending on system improvements to accommodate growth during the Current PBR Plan term, including any factors which are related to unexpected increases in the unit cost of system improvements.

Response:

While FBC has done its best in Appendix B8-3 to explain its annual variances between formula and actual capital during the Current PBR Plan term, it is difficult to provide meaningful variance explanations because the formula capital is based on a 2013 spending allowance escalated by a formula amount. Further, the formula capital is set on an aggregated basis, meaning there is also no set formula amount for spending on system improvements to accommodate growth during the Current PBR Plan term.

Overall, FBC experienced higher customer growth over the Current PBR Plan term than had been forecast at the outset of the term. This growth resulted in potential capacity constraints in localized areas or regions and drove the need for system improvements or reinforcements.

As set out in Appendix B8-3, system improvements are projects related to increased capacity, equipment and services upgrades, voltage regulation, feeder ties, and load transfers, which are required to keep pace with normal load growth on the transmission and distribution systems. They also include work to connect new customers and to ensure continuing acceptable standards of service.

As noted in the May 1, 2019 workshop,[9] FBC has not developed a unit cost analysis for Growth capital expenditures generally, and does not believe it is possible to develop a unit cost for system improvements specifically.

10.4 Please compare and contrast the issues and factors which contributed to the growth capital variances and the sustainment/other capital variances between FEI and FBC.

Response:

The main contributors to FEI's cumulative capital expenditures variance compared to formula, as identified in Table A:B8-1-4 for Sustainment and Other Capital in Appendix B8-1, were:

- PBR decisions:
  - Reduction to FEVI's base sustainment capital - $32.5 million;
  - PBR decision growth factor for net customer additions - $12.5 million;
  - PBR decision growth factor for service line additions - $19.0 million; and
  - PBR formula pressures resulting from increase in PIF - $5.1 million.
- Unanticipated expenditures related to higher than expected growth:
  - New Customer Mains and Services activity and cost variance - $108.8 million;
  - Unanticipated system improvements and new stations - $10.7 million;
  - Whistler IP pipeline - $11.7 million; and
  - Operations Fleet Requirements - $7.3 million.

Overall, 95 percent of the cumulative $219.4 million FEI capital variance from formula is attributable to the items listed above. The strong growth experienced during the Current PBR Plan term impacted not just Growth capital, but also Sustainment and Other capital. In Sustainment capital it necessitated the accelerated or unplanned construction of system reinforcements and new stations to meet demand of new customers and maintain service levels for existing customers. In Other capital, it required the purchase of additional vehicles and equipment for crews to meet service targets for new customer service installations.

[9] Transcript Volume 1, page 37.

The main contributors to FBC's cumulative capital expenditures variance compared to formula, as identified in Table A:B8-3-1 in Appendix B8-3, were:

- PBR decisions:
  - PBR decision growth factor for net customer additions - $1.0 million; and
  - PBR formula pressures resulting from increase in PIF - $1.2 million.
- System improvements to accommodate growth - $20.9 million;
- Newly identified sustainment capital work:
  - Due to weather events - $1.9 million;
  - Third Party forced relocations - $5.9 million; and
  - Newly identified projects and scope definition - $11.6 million.

As shown above, 46 percent of the cumulative $49.7 million FBC capital variance to formula is attributable to the PBR decisions and upgrades required to support customer growth. Another 39% of the variance is attributable to newly identified Sustainment capital work that includes urgent work due to weather events, forced relocations by third parties, and projects to address evolving WorkSafeBC legislation.

Both FEI and FBC experienced significant cost pressures from Growth capital during the Current PBR Plan term; however, FEI experienced a comparatively larger impact to the overall capital variance to formula. As described in Appendix B8-1, FEI's Growth capital was impacted by both higher volumes of customer additions and changes in the type of installation. The increased number of customers per service line and the regional distribution of additions, along with evolving municipal requirements, led to an increased unit cost overall. The combined volume and cost impacts led to significant variances in FEI's Growth capital compared to formula.

The Sustainment and Other capital categories for FEI and FBC saw similar pressures over the Current PBR Plan term. Both saw impacts due to natural forces: flooding and land movement on the FEI system and weather events and fires on the FBC system. Both companies were also required to accommodate third party forced relocations of assets with relatively short notice provided by the proponents of the work. Both FEI and FBC routinely identified new work and additional project scope within the Current PBR Plan. Although FEI is more able than FBC to minimize the impacts of additional work requirements due to its relatively larger size, with the cumulative impacts of the Growth capital pressures and the 2014 PBR Decisions that reduced available capital, both Companies were unable to meet system sustainment needs within the allowed capital funding during the term of the Current PBR Plans.

10.4.1 As part of the above response, please explain the key differences in FEI and FBC's sustainment/other capital and growth capital and how these differences may have impacted each utility's capital spending results during the Current PBR Plan term.

Response:

Please refer to the response to BCUC IR 1.10.4.

On page 3 of Appendix B8-3, FBC states that it anticipates capital expenditures to exceed the formula in 2019 due to factors which include unanticipated transmission projects to address safety and reliability issues.

On page 4 of Appendix B8-3, FBC states that there is one unanticipated transmission project in the Crawford Bay area required to address safety and reliability concerns.

10.5 Please explain why this project was unanticipated.

Response:

The project referenced in the preamble is referring to as the 30 Line Right of Way project, which is part of the scope of work described on page C-90, lines 26-33 of the Application. FBC's 30 line is situated between Nelson and FBC's Coffee Creek Substation and also supplies the Crawford Bay area on the east shore of Kootenay Lake. It is situated in steep terrain and is prone to outages from weather events and from tree contacts originating outside the right of way. This project was created in 2018 to address concerns raised by customers along the east shore of Kootenay Lake and also addresses concerns raised by the City of Nelson regarding reliability of supply.

10.6 Please explain how FBC develops its forecast for transmission projects to address safety and reliability issues and why this project was not able to be accommodated within the formula spending.

Response:

The first part of this response addresses the development of forecasts for transmission projects.

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. Transmission Sustainment capital is further broken down into four programs:

- Transmission Line Condition Assessment;
- Transmission Line Rehabilitation;
- Transmission Urgent Repairs; and
- Transmission Rights of Way.

These programs are described on pages C-89 to C-90 of the Application.

Condition assessments of FBC's lines are carried out on an eight-year cycle. The specific lines expected to be assessed (and therefore the approximate number of structures) during the MRP period are therefore known for each year. The pole test and treat component of the condition assessment is performed by approved contractors, and the contracts are used to determine a unit cost which is applied to the volume of poles to be treated in each year. The remainder of the costs for condition assessment are determined based on historical per-unit costs escalated for inflation. To the extent possible FBC endeavours to levelized the volume and costs associated with the condition assessment program from year to year by managing the sequence of lines to be assessed.

Transmission Line Rehabilitation costs are forecast by region, based on the number of poles in the prior year's condition assessment program and the inflation-adjusted historical unit cost of rehabilitation. (As the number of structures to be rehabilitated can not be known in advance, the unit costs are determined on the basis of poles assessed, which assumes a constant proportion of poles for rehabilitation to poles assessed.) In the 2020-2024 term, additional funds to replace insulators were added.

Transmission urgent repairs involves the repair or replacement of transmission equipment that fail in service due to severe weather, vandalism or for other unexpected urgent reasons, in addition to the poles identified during the condition assessment for immediate repair in the same year. FBC forecasts urgent repairs using an inflation-adjusted three-year rolling average.

Similarly, FBC uses a three-year rolling average to forecast its expenditures on rights of way. Also included in this category during the MRP term are specific projects for the acquisition of additional rights of way, which for the 2020-2024 period are described on page C-90 of the Application.

The second part of this response addresses why the unanticipated transmission project in the Crawford Bay area was not able to be accommodated within the formula spending.

Under the Current PBR Plan, FBC does not have a formula for the transmission or other components of capital expenditures. Formula capital spending is determined by escalating the 2013 Base capital values at the aggregate level. Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts.

FBC identified the specific factors and projects included in Appendix B3-8 in response to a BCUC directive in Order G-38-18, which requested the breakdown as an aid to explaining the variance between actual/forecast capital expenditures and the approved formula capital amount. FBC was directed to update the information in Order G-246-18. Table B3-8-1 and the accompanying discussion in Appendix B3-8 to help to explain the reasons that it has been necessary at an aggregate level for FBC to exceed the formula capital amount.

FBC has sought to provide as much clarity as it can to understand the reasons for variances from formula; however, there is in fact no definitive or correct way to identify which of its total capital expenditures are within the formula amount, within the dead band, or outside of the dead band.

Although FBC has, from necessity, relied on the specific projects and timing that it identified in the capital expenditures “forecast” from the PBR Application to respond to the BCUC’s directive, this forecast did not form the basis of a capital “budget” for the PBR term. Rather, FBC’s Base capital was approved by the BCUC to be equal to FBC Approved 2013 capital, as adjusted, which is then subject to the formula over the term of the PBR Plan. The Company anticipated, based on the flexibility endowed by entering into a PBR Plan, that it would re-evaluate the need and timing of capital projects on an ongoing basis. There is therefore no definitive way to identify what capital is inside or outside of the formula amount, and no way to respond to why a specific project could not be accommodated within the formula.

11.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.3.4.1, p. B-42

FEI Delivery Rate Changes

In Figure B2-4 on page B-42 of the Application, FortisBC provides the annual delivery rate changes for FEI during the Current PBR Plan term.

11.1 For each year of the Current PBR Plan term, please identify the percentage contribution (positive or negative) each of the following made to the annual delivery rate change:

- Delivery revenue;
- Formula O&M;
- Forecast O&M;
- Depreciation expense;
- Amortization of flow-through deferral account;
- Other deferral account amortization;
- Financing and return on equity (ROE); and
- Other.

Response:

FortisBC provides the response below for FEI's delivery rate changes. For years 2017 and 2018, the 'Other' contribution to delivery rates is due in part to the deferred revenue surplus in those years.

Contribution to Annual Delivery Rate Change	2014	2015	2016	2017	2018	2019
Delivery Revenue	-1.6%	0.5%	0.8%	-1.9%	-5.8%	-1.7%
Formula O&M	-0.3%	0.2%	0.3%	0.3%	0.3%	0.6%
Forecast O&M	0.0%	0.1%	-0.2%	-0.5%	0.3%	0.0%
Depreciation Expense	0.2%	0.7%	0.8%	-0.3%	2.6%	1.2%
Amortization of Flow-through Deferral Account	0.0%	-0.4%	0.3%	-0.6%	-0.9%	-1.5%
Other deferral account amortization	1.7%	-0.3%	0.2%	-0.7%	1.0%	1.4%
Financing and ROE	-0.5%	-0.3%	-0.5%	-1.1%	-1.0%	0.2%
Other	2.3%	0.2%	0.1%	4.8%	3.5%	0.9%
Approved Delivery Rate Change	**1.8%**	**0.7%**	**1.8%**	**0.0%**	**0.0%**	**1.1%**

1

2

12.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.3.4.2, p. B-43

FBC Rate Changes

In Figure B2-5 on page B-43 of the Application, FortisBC provides the annual rate changes for FBC during the Current PBR Plan term.

12.1 For each year of the Current PBR Plan term, please identify the percentage contribution (positive or negative) each of the following made to the annual rate change:

- Sales revenue;
- Power supply expense;
- Formula O&M;
- Forecast O&M
- Depreciation expense;
- Amortization of flow-through deferral account;
- Other deferral account amortization;
- Financing and ROE; and
- Other.

Response:

FortisBC provides the response below for FBC's rate changes.

Contribution to Annual Rate Change	2014	2015	2016	2017	2018	2019
Revenue	-0.8%	-8.5%	-1.8%	-0.5%	1.6%	-3.8%
Formula O&M	0.9%	0.1%	0.2%	0.1%	0.2%	0.3%
Forecast O&M	0.8%	-0.5%	-0.7%	0.0%	0.1%	-0.2%
Depreciation Expense	1.0%	0.8%	-0.3%	0.5%	0.7%	0.5%
Amortization of Flow-through Deferral Account	-3.4%	3.4%	-0.3%	1.9%	-3.7%	-1.5%
Other deferral account amortization	1.3%	-2.9%	0.3%	-1.2%	2.3%	0.0%
Financing and ROE	-1.1%	-0.4%	0.2%	0.4%	0.3%	0.4%
Other	4.5%	12.2%	5.4%	1.6%	-1.4%	4.3%
Approved Rate Change	**3.3%**	**4.2%**	**3.0%**	**2.8%**	**0.0%**	**0.0%**

The contribution of “Other” to overall rate changes includes the deferral of revenue surpluses in 2014 and 2019 and the revenue deficiency in 2018, and Power Supply costs, largely due to the Waneta Expansion Capacity Purchase Agreement, in 2015 and 2016.

13.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.3.5, pp. B-18, B-44 – B-48; Exhibit B-1-1, Appendix C4-1; FEI 2014-2018 PBR Application proceeding, Exhibit B-1, p. 17

Analysis of Strengths and Weaknesses

On page B-44 of the Application, FortisBC states the following:

> 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. As such, it is reasonable to assume that a similar approach to O&M expenditures in future MRP designs would be appropriate.

On page B-47 of the Application, FortisBC states the following:

> 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. 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 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".

13.1 Please explain why FortisBC has not specifically identified the productivity factor for FEI (1.1 percent) and FBC (1.03 percent) as a key strength of the Current PBR Plans.

Response:

The strength of the incentives of the Current PBR Plans are derived from the decoupling of cost and revenues of the utility during the rate period, the length of the rate period, the type of the costs that are subject to incentive framework and the earnings sharing mechanism applied (if any) and not the X-Factor value. The X-Factor is there only to adjust the economy-wide inflation

factor (used as a proxy for the utility's cost inflation in the indexing formula) for any variance with the utility's real cost inflation. Please also refer to the responses to BCUC IRs 1.6.3 and 1.13.2.

13.2 Given the success of FEI and FBC's formula O&M in the Current PBR Plans, and in consideration of the level of annual savings achieved, please explain why FortisBC does not consider it reasonable to include some degree of productivity factor in the proposed indexed approach to O&M. Please provide a separate response for FEI and FBC.

Response:

FortisBC's proposal to not recommend an X-Factor value for the index-based O&M (implying a zero percent X-factor value) reflects its assessment that the economy-wide composite inflation index is expected to track the Companies' price inflation during the term of the MRPs and in some cases, may even be insufficient to compensate the Companies' higher input cost growth required to prepare the Utilities for the rapid industry transition in the upcoming term of the MRPs.

The following describes the theory of the I-X mechanism, and then explains the basis for FEI's and FBC's proposal for a zero percent X-factor value.

Theory of the I-X Mechanism

The theory of the I-X mechanism defines the X-Factor value as an adjustment to the inflation factor (I-Factor) for the difference between the economy-wide inflation factors (used in the indexing formula) and the real cost inflation of the utility.

The excerpt below from a report prepared by Regulatory Assistance Project (RAP)[10] for the National Association of Regulatory Utility Commissioners (NARUC) entitled "Performance-based regulation for distribution utilities" explains the function of X-Factor as follows[11]:

> The productivity, or x, factor is an adjustment to the inflation factor. One could argue for the importance of the productivity factor in sharing PBR benefits with

[10] The Regulatory Assistance Project (RAP) is an independent, non-partisan, non-governmental organization. RAP helps decision-makers and stakeholders navigate the complexities of power sector policy, regulation, and markets.

[11] https://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf

consumers or forcing utilities to improve productivity, but the reality is much simpler.

There are many measures of inflation. In addition to the CPI, other familiar indices are the producer price index (PPI), the retail price index (RPI), and change in the gross domestic product (GDP). None of these is especially good at explaining historical or projected differences in utility costs. Nor are these indices useful in describing utility revenue growth. The main purpose of the x factor is to adjust the inflation factor (whatever it may be) so that the resulting multiplier, (i-x), produces a reasonable level of revenue growth or a reasonable level of anticipated cost growth. Thus, most PBRs have approached the issue by comparing trends in specific inflation indices to the utility's total cost trends. This analysis – the total factor productivity – identifies how utility costs have been controlled relative to inflation.

The variance between economy-wide inflation factor used in the formula and the utility's actual inflation depends on two factors: (i) the variance between the economy-wide inflation and the input cost inflation of the utility and (ii) the variance between the average productivity of the economy and the productivity of the utility. The Body of Knowledge on the Infrastructure Regulation (BoKIR)[12] describes this issue as follows[13]:

Inflation reflects two things, namely, the change in the value of the country's money and the change in the productivity of the firms in the economy. By definition, the input prices for the average firm in the economy change at the rate of inflation and its productivity changes at the average rate for the economy. As a result, the average firm's retail prices change at the rate of inflation and the firm continues to receive earnings that are equal to its cost of capital.

Now consider how a utility operator might be different from the average firm in the economy. First, assume that the operator is just like the average firm, except that the operator's input prices change at a rate that is different from the rate of change for the average firm. If the operator's input prices increase faster than (conversely, slower than) the rate of inflation, then the operator's retail prices (revenue) will need to increase faster than (conversely, slower than) the rate of inflation for the operator to be able to have earnings that are at least as great as the operator's cost of capital.

[12] Developed by the Public Utility Research Center (PURC) at the University of Florida, in collaboration with the University of Toulouse, the Pontificia Universidad Catolica, the World Bank and a panel of international experts, the Body of Knowledge on Infrastructure Regulation (BoKIR) summarizes some of the best thinking on infrastructure policy. Funding for this project came from the Public-Private Infrastructure Advisory Facility (PPIAF).

[13] http://regulationbodyofknowledge.org/price-level-regulation/features-of-price-cap-and-revenue-cap-regulation/.

> Now assume that the operator is just like the average firm, except with respect to the operator's ability to improve efficiency. If the operator increases its productivity faster than (conversely, slower than) the average firm, then the operator's retail prices (revenue) will need to decrease (conversely, increase) relative to the rate of inflation.
>
> Combining these two possible differences between the operator and the average firm in the economy, the operator's retail prices (revenue) should change at the rate of inflation, minus (conversely, plus) the extent to which its input prices inflate less than (conversely, greater than) the rate of inflation, and minus (conversely, plus) the extent to which the operator's productivity is expected to improve at a rate that is greater than (conversely, less than) the average firm in the economy.

In this context, a zero percent X-Factor implies that the economy-wide inflation used in the formulas is expected to track the utility's cost inflation.

Consistent with the above, Dr. Makholm's evidence in Union Gas' and EGD's amalgamated incentive rate-setting proceeding summarizes the need for inclusion of an X-Factor value as follows:

> With respect to the sign of the X-factor as part of a price cap index for a defined regulatory period, the following is a reasonable summary:
>
> - A positive X-factor indicates expected lower input cost growth or higher productivity growth for the regulated enterprise, vis-à-vis the economy as a whole, which means that economy-wide inflation indexes would overstate the regulated firm's price inflation during the rate formula period.
> - A zero X-factor means that the economy-wide inflation index is expected to fairly track the regulated firm's price inflation during the rate formula period.
> - A negative X-factor means that the economy-wide inflation index is expected to be insufficiently large for the purpose of tracking the regulated firm's price inflation during the rate formula period.

Basis for FortisBC's Proposal

As stated at the outset of this response, FortisBC's proposal to not recommend an X-Factor value for the index-based O&M (implying a zero pecent X-factor value) reflects its assessment that the economy-wide composite inflation index is expected to track the Companies' price inflation during the term of the MRPs and in some cases, may even be insufficient to compensate the Companies' higher input cost growth required to prepare the Utilities for the rapid industry transition in the upcoming term of the MRPs.

As stated in Section C2.3 of the Application, both FEI and FBC anticipate experiencing cost pressures that are either not included in the proposed Base O&M and/or that are anticipated to be above the forecast composite inflation factor.

FBC, for instance, anticipates additional cost pressures for increased engineering and technology staffing to maintain its various technology platforms such as Supervisory Control and Data Acquisition (SCADA), Outage Management System (OMS), Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI) and Geographic Information System (GIS). Similarly, FEI anticipates incremental costs not included in Base O&M related to items such as O&M costs associated with capital projects and the incremental costs associated with upcoming retirements (increased turnover and filling key positions before employees retire to enable smooth transitions). Both FEI and FBC also anticipate increased cost pressures in general and administrative costs (HR, Finance and Procurement) and meeting evolving municipal regulation, as well as other environmental and safety requirements that are not considered in the Base O&M for either Company.

Further, as mentioned in Section C2.3, in a number of areas such as insurance and vehicle related costs, fees for rights of way and facilities lease contracts, FortisBC is already experiencing higher input cost growth than the economy-wide inflation numbers. This indicates a need for a negative X-Factor and shows that FortisBC's recommendation to index O&M unit costs to inflation is already challenging and requires a continuous search for efficiencies and cost savings opportunities to manage these cost pressures.

FortisBC also took into consideration the following items for its proposed implied zero percent X-Factor value:

<u>Review of X-Factor value related expert testimonies and regulatory decisions in other jurisdictions:</u>

The review of expert testimonies and regulators' decisions in other jurisdictions (a summary of which is included in Appendix C4-2 of the Application) provided two important insights regarding the X-Factor determination:

i. Increased importance of regulatory judgement for X-Factor determination:

The review of X-Factor decisions in other jurisdictions indicates a move away from a pure Total Factor Productivity (TFP) approach to an increased application of regulatory judgment for X-Factor determination. That is, in comparison with previous generation PBR plans, the variance between TFP values computed by experts and the X-Factor values proposed by experts and/or approved by the regulator has widened[14]. This means that both experts and regulators are

[14] For instance in the case of Alberta, while the variance between the approved productivity growth number of +0.96 percent (generated by NERA/Makholm) and the approved X-Factor in AUC's first generation PBR was +0.2 percent (the variance relates to the judgement-based stretch factor of 0.2 percent), the variance between similar

giving less weight to the results of TFP studies and applying more judgment to derive the final proposed or approved X-Factor value.

For instance, in Alberta the AUC distanced itself from its previous decision to set the X-Factor predominately based on TFP results and used its judgement to reach to its final X-Factor value of 0.3 percent from a range of TFP values without providing any specific stretch factor amount[15]:

> The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable range of values, between -0.79 and +0.75. The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor, will be 0.3 per cent.

A comparison of experts' TFP values with their proposed X-Factor in the Union Gas and Enbridge Gas incentive regulation proceeding indicates a similar trend. A review of the OEB's recent decision in this proceeding indicates that the regulator did not comment on the merits of individual studies and relied on its judgement to arrive at its final determination of a 0.3 percent X-Factor (zero percent productivity plus 0.3 percent stretch factor).[16] In that case, the two experts both proposed a judgement-based base productivity growth of zero percent (both experts used their judgement to propose a zero percent productivity growth instead of relying on the results of their Total Factor Productivity studies). The OEB stated:

> The OEB accepts the applicants' proposal for a productivity factor of 0% during the deferred rebasing period. There were two expert reports filed in evidence in this proceeding on the productivity factor; one from NERA for the applicants and another from PEG for OEB staff. While the approach to determining an appropriate productivity factor differed, both experts recommended a productivity factor of 0%. Considering that the experts' recommendation is the same, the OEB will not opine on the merits of the methodology adopted in the reports.

Also recently, the Régie de l'énergie in Quebec (the Regie) used its judgement informed by the TFP studies in other North American jurisdictions to set the 0.3 percent X-Factor for Hydro-Quebec Distribution's first generation PBR without any TFP study prepared specifically for the

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updated NERA studies and approved X-Factors is approximately one percent.

[15] AUC Decision 20414-D01-2016, P.45, para 169.

[16] OEB Decision (Aug, 2018); pp 25-26

Hydro Quebec case. FEI also notes that the use of a judgement-based approach has precedent in BC's PBR history albeit through negotiated settlement.

ii. A downward trend in both utility and interveners' experts computed TFP growth numbers and the corresponding decline in approved X-Factor values:

The table below provides a summary of the results and major characteristics of the various recent productivity studies studied by FortisBC in preparing its Application.

Proceeding	Expert	Evidence date	Retained by	Productivity results	X-Factor proposed	X-Factor approved	Description
Union/EGD Amalco PBR	Dr.Lowry / PEG	May 2018	OEB staff	TFP= -0.23%	0.3%	0.3%	58 T&D NG utilities in U.S. / 1999-2016
	Dr.Makholm / NERA	Nov 2017	Utilities	TFP= 0.54% Adjusted= 0.35%	0.00%		65 utilities, Combination of NG &Elec / 1973-2016
Not Applicable	Dr.Lowry et al. / PEG	Jul 2017	Berkeley Lab/ DOE	TFP range: 0.22% to 0.45%	N/A	N/A	86 Elec and combination of NG& Elec utilities
Alberta 2nd Generation PBR	Dr.Meitzen / Christensen	March 2016	EPCOR	TFP=-1.11 %	-1.11%	0.3%	68-72 utilities, Updated NERA TFP, Avg. of 2000-2014 & 2005-2014
	Drs. Brown & Carpenter / Brattle	May 2016	Utilities	TFP= -0.79%	-0.79%		Updated NERA TFP, 67 utilities, 2000-2014
	Dr.Lowry / PEG	Jun 2016	CCA	TFP= 0.43% & 0.78%	0.63% & 0.98%		88 & 21 utilities, 1997-2014
Hydro Quebec Dist (HQD)	Dr.Lowry / PEG	Jan 2018	AQCIE-CIFQ	TFP range: 0.22% to 0.45%	0.3%	0.3%	Based on Berkeley Lab's study and expert's judgement
	Coyne / CEA	Jan 2018	HQD	-0.75%	-0.5%		The estimate was based on review of TFP results in other jurisdictions, not a standalone TFP study

A review of TFP growth results generated by experts in the table above indicates that productivity growth numbers are trending downward. This issue was highlighted in AUC's 2016 decision[17]:

> As shown in Table 1, all final recommendations concerning the TFP growth component of the X factor are lower than, and in some cases much lower than,

[17] AUC Decision 20414-D01-2016, p.41, para. 156.

> the TFP growth number of +0.96 per cent adopted by the Commission in Decision 2012-237. Consequently, as noted previously, based on the expert evidence received in this proceeding, the issue before the Commission is not whether the TFP growth component of the current X factor needs to be lowered for the next generation PBR, but rather the extent to which it needs to be lowered.

For more information regarding the downward negative trend in productivity growth numbers refer to the X-Factor sections of Appendix C4-2.

FEI's and FBC's performance during the PBR period:

As explained in Section B2.3.1 of the Application, both FEI and FBC have been under multiple PBR plans and were able to achieve sizable O&M savings in each year of Current PBR Plans. A large part of the savings under the Current PBR Plans were permanent in nature and are reflected in the 2019 Base O&M for the proposed MRPs. As a result of years of O&M savings being achieved under successive PBR terms, the opportunities for additional O&M cost reductions have been steadily diminishing and there is now limited potential for future productivity gains. In other words, there is no low-hanging fruit left to pick. This conclusion is supported by the results of Concentric's benchmarking study, as discussed below.

Concentric's benchmarking study results:

The Utility performance benchmarking can be used to inform the X-Factor determination decision. The benchmarking of O&M and capital expenditures for example can be used to estimate the relative cost efficiency of a utility compared to its peer group. Similarly, the benchmarking of non-financial metrics (service quality indicators) can be used to consider the "safety and reliability" aspects of the utility operations that are not incorporated in productivity growth. The unit cost benchmarking results indicates that establishing an additional efficiency factor for O&M indexing formulas is not warranted as both FEI and FBC have been operating under PBR for number of years and are relatively more efficient than the median of their peer companies in the majority of benchmarked metrics (and for all the O&M metrics). Please refer to the response to BCUC IR 1.16.1 for more information.

Summary

Based on the evidence, including FEI's and FBC's assessment of O&M cost pressures during the proposed MRP period, the insights gained from its review of X-Factor related evidence and decisions in other jurisdictions (the increased importance of judgement as well as rapidly declining industry productivity growth values in recent years), the result of Concentric's benchmarking study, as well as in consideration of the Companies' performance during the Current PBR period, FortisBC's proposal to not recommend an X-Factor in its O&M determination (which can also be expressed as an implied zero percent X-Factor) is appropriate. This proposal will incent the Companies to keep controllable cost increases below

the rate of inflation by finding additional efficiency opportunities while maintaining the current high levels of service quality.

13.2.1 As part of the above response, please explain the specific analysis which FEI and FBC have each performed to conclude that no productivity factor or stretch factor can reasonably be incorporated into each utility's O&M formula as part of the proposed MRPs.

Response:

Please refer to the response to BCUC IR 1.13.2.

13.3 Please discuss the reasonableness of including a combination of cost efficiency targets for indexed components of the MRPs (e.g. the inclusion of a productivity factor) and FortisBC's proposed targeted incentives as part of FortisBC's overall MRP design. Please provide a separate response for FEI and FBC.

Response:

FEI's and FBC's proposed MRPs already include elements of both cost efficiency targets and targeted incentives. An indexed-based approach with a zero percent X-Factor, as FortisBC has proposed, has a cost efficiency target. As explained in the response to BCUC IR 1.6.3, the strength of the incentives in a rate plan to promote efficiency gains is primarily derived from the decoupling of the costs and revenues, the amount of costs subject to incentives and the length of the MRP period (the incentives are also impacted by the inclusion of an earnings-sharing mechanism) and not the X-Factor value.

The index-based formulas in the proposed MRPs provide an incentive to maintain spending at, or below, inflation while managing emerging cost pressures. In short, the target embedded in the indexed components of the MRPs is inflation. This approach promotes a continuous focus on containing costs, while also incorporating a productivity focus of "doing more with the same". Section B2.3 of the Application describes examples of the types of cost pressures that FEI and FBC expect to manage within the proposed index-based O&M during the term of the MRPs. Similarly, the forecast capital costs include an incentive for cost efficiency as any variance between forecast and actual capital amounts is shared between the Utilities and customers for

the MRP period. FEI and FBC do not believe it would be reasonable to implement cost efficiency targets for indexed components of the MRPs beyond what has already been proposed. Please also refer to the response to BCUC IR 1.13.2.

While the cost efficiency targets aim to improve the Companies' allocative and productive efficiencies, the proposed targeted incentives and the Innovation Fund are designed to prepare the Utilities for the future challenges and therefore are there to incent improvements in dynamic efficiencies through investments in innovative solutions that can reduce the long-run average cost (unit cost) of the Companies over time. The following addresses these separately for FEI and FBC:

- FEI is impacted to a much greater degree by policy direction and mandates at all levels of government towards decarbonization. The addition of targeted incentives helps place focus on addressing emissions and supporting the transition to a lower carbon economy while serving FEI's customer needs. As a result, four out of five targeted incentives address emissions-related challenges and opportunities while the fifth addresses changing customers' expectations to engage with FEI conveniently through digital communications channels. Expanding the focus to address these emerging areas of utility performance is not only in the public interest, but it will ultimately benefit FEI's customers.
- FBC is impacted to a lesser degree by policy direction, so its suite of targeted incentives focus on a wider array of performance areas including increasing customer engagement, supporting BC's zero emissions vehicle mandate, and optimizing power purchase costs. The Power Supply Incentive adds an additional focus on cost efficiency by creating greater incentive to optimize FBC's single largest cost. Accordingly, FBC's targets include sufficient focus on cost efficiency while also providing important focus on areas such as climate change and customer engagement that are beneficial to customers and the public.

FortisBC has therefore proposed a reasonable and balanced combination of cost efficiency and targeted incentives in the proposed MRPs.

In Appendix C4-1 to the Application, FortisBC provides an article from the Electricity Journal titled "The rise and decline of the X factor in performance-based electricity regulation."

13.4 Please confirm, or explain otherwise, that the article in Appendix C4-1 refers to electric utilities only and not to natural gas utilities.

Response:

FortisBC confirms that the mentioned article only focused on electric distributors (as it was published in the Electricity Journal). However, the issues raised in the article are not limited to electric distributors. The author of this article, Dr. Makholm, provided similar evidence in the Union Gas and Enbridge Gas Distribution amalgamated incentive rate-setting proceeding, which indicated that the total factor productivity values have been trending downward in recent years (negative average TFP growth in at least the last 10 years) due to rapidly rising costs that do not contribute to increased throughput or new customers (traditional utility output metrics). Dr. Makholm concluded that he does "not recommend an X-factor for EGD or Union for their upcoming 10-year rebasing periods".

13.4.1 If confirmed, please explain the relevance of the article to FEI.

Response:

Please refer to the response to BCUC IR 1.13.4.

13.5 Please explain in detail how the analysis and conclusions contained in the article in Appendix C4-1 specifically relate to FBC's and FEI's operating environments and circumstances.

Response:

Dr. Makholm's article titled "the rise and decline of the X-Factor in performance-based electricity regulation" published in the Electricity Journal contains the following high-level discussions:

- The origins of the I-X mechanism and discussion of why and when an inclusion of an X-Factor is needed to adjust the economy-wide inflation index;
- The changing nature of investments in the energy industry leading to the recent significant downward trend in industry productivity numbers; and
- Discussion of new incentive frameworks adopted by other North American regulators to promote innovative solutions for industry transition challenges.

As part of the discussions around the changing nature of utility investments, the article points out that many new investments and operating expenses are non-revenue generating activities where increased costs do not lead to higher output levels (as measured by traditional utility outputs such as number of customers or throughput). This issue is the main reason for declining industry productivity growth in the last 10 to 15 years. The article specifically mentions AMI-related investments as well as investment in a range of grid modernization technologies related to EV charging, electrical storage, voltage optimization, data management and cybersecurity as examples for electric distributors.

As explained in various sections of the Application, both FEI and FBC are experiencing higher capital and O&M cost pressures in a number of areas without equivalent offsetting revenues.

FBC, for instance, has incurred many of the same costs mentioned as examples in the article. FBC's investments in automated metering, cyber security, and information technology and data management platforms are all within this category.

FEI also has many similar investment needs in areas such as cybersecurity or data management as well as the need for incremental expenditures related to safety and environmental regulations, customer and Indigenous engagement activities, and large sustainment projects that have no impact on FEI's traditional measured outputs.

FEI's and FBC's proposals to introduce Targeted Incentives and an Innovation Fund as well as the proposed zero percent implied productivity factor reflect the changing nature of the Companies' investment needs and its impact on the Companies' output growth and input growth levels.

On page B-45 of the Application, FortisBC states that "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 expenditure limits."

13.6 Please provide the total actual amount of capital expenditures for 2014 through 2018 for each of FEI and FBC which exceeded the capital dead-band and were therefore removed from the earnings sharing calculation and added to opening plant in service. Please provide both the annual amounts and the cumulative total amounts for the Current PBR Plan terms.

Response:

In the tables below, FortisBC has provided the 2014- 2018 actual capital amounts exceeding the capital dead band that were therefore removed from the earnings sharing calculation and added to opening plant in service.

The incremental revenue requirement and rate impacts cannot be precisely calculated because the adjustments are spread among many asset classes. Consequently, FortisBC used average depreciation rates and average CCA rates to determine an approximate revenue requirement and rate impact. Additionally, because the adjustments are to capital, their impact on the revenue requirements is already cumulative so they cannot be summed across the years. Finally, the ESM adjustment that occurs in one year becomes the rate base adjustment in the following year.

The following tables provide the approximate revenue requirement and bill impacts from the dead band adjustments.

Table 1: FEI Adjustments to Earnings Sharing/ Opening Plant Balance, Revenue Requirement and Bill Impact

FEI ($000) Year	2014	2015	2016	2017	2018	2019	Total
ESM Adjustment	-	-	(9,176)	(37,632)	(73,160)	-	(119,968)
Following Year Opening Rate Base Adjustment				9,176	37,632	73,160	119,968
Revenue Requirement	-	-	-	612	3,271	8,980	
Bill Impact	0.0%	0.0%	0.0%	0.1%	0.3%	0.7%	

Table 2: FBC Adjustments to Earnings Sharing/ Opening Plant Balance, Revenue Requirement and Bill Impact

FBC ($000) Year	2014	2015	2016	2017	2018	2019	Total
ESM Adjustment	-	-	-	(12,075)	(14,122)	-	(26,197)
Following Year Opening Rate Base Adjustment				-	12,075	14,122	26,197
Revenue Requirement	-	-	-	-	754	1,988	
Bill Impact	0.0%	0.0%	0.0%	0.0%	0.2%	0.5%	

13.6.1 As part of the above response, please also provide the incremental revenue requirement and rate impact of these capital expenditures annually and cumulatively for FEI and FBC.

Response:

Please refer to the response to BCUC IR 1.13.6.

On page B-48 of the Application, FortisBC states the following:

> 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…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…

13.7 Please identify and describe FBC's strategic long-term initiatives that are currently treated outside the PBR framework. Please also provide the total expenditures (O&M and capital) on these initiatives during the Current PBR Plan term.

Response:

To date the only strategic long-term initiative of FBC that is outside of the PBR framework is the investment in EV charging stations. Pursuant to Order G-9-18, the costs of FBC's EV DCFC stations are excluded from rate base until the BCUC directs otherwise. FBC anticipates that the outcome of Phase 2 of the BCUC's EV Inquiry will permit public utility investment in EV chagring stations, and allow for their recovery through rate base treatment. If so, FBC will return the EV charging station assets and operating costs to the regulated rate base upon approval. The capital expenditures, CIAC, and operating costs associated with EV charging stations are provided in the table below.

	2017	2018	2019P
		$000s	
Capital Expenditures	316	322	1,323
CIAC	(177)	(246)	(900)
O&M	-	7	8

13.8 Please provide FEI's annual and cumulative expenditures (O&M and capital) on initiatives treated outside of the PBR framework (as described in the above preamble) during the Current PBR Plan term.

Response:

The following table provides 2014 through 2018 actual and 2019 forecast O&M and capital expenditures on RNG and NGT initiatives treated outside of the formula O&M and capital.

($000)	2014A	2015A	2016A	2017A	2018A	2019F	Total
RNG							
O&M	417	1,085	1,154	1,567	2,634	1,369	8,226
Capital	3,656	1,350	1,346	965	45	12,861	20,223
NGT							
O&M	484	1,009	1,205	1,508	2,099	2,339	8,644
Capital	5,816	5,607	5,797	2,134	1,730	8,455	29,539

13.9 Please confirm, or explain otherwise, that the majority of FEI's initiatives which are treated outside the PBR framework are considered prescribed undertakings under the GGRR.

Response:

FEI confirms that initiatives such as RNG and NGT that are treated outside the formula O&M and capital are supported by prescribed undertakings in the GGRR. However, elements of both RNG and NGT businesses are not due to GGRR prescribed undertakings, e.g., the RNG initiative was under development for a number of years before the RNG prescribed undertaking were established. Further, the GGRR is only one of a number of possible mechanisms to enable long-term initiatives. FEI has other programs outside the formula O&M and capital amounts that are larger in magnitude than prescribed undertakings under the GGRR. FortisBC's DSM activities and expenditures are an example of a larger program area that is outside the PBR framework altogether. In addition, there are capital projects that are treated as flow-through, such as the Tilbury LNG expansion, that will continue to be significant contributors to FEI's long-term initiatives.

13.10 Please explain whether FortisBC considers the GGRR provisions of the Clean Energy Act to be a form of incentive for FEI to develop innovative solutions.

Response:

Prescribed undertakings under the GGRR may in some, but not all cases, provide opportunities for FEI to pursue innovative solutions. However, the benefit to the utility is limited to recovery of the prescribed undertaking costs in revenue requirements, rather than being an incentive per se. Prescribed undertakings do not incent the utility to focus extraordinary efforts on the achievement of the particular objectives by allocating resources to the areas of focus. Further, the cost recovery protection is limited to activities that fall within the definition and parameters of the "prescribed" undertakings.

The purpose of prescribed undertakings (termed projects, programs, contracts or expenditures) under section 18 of the *Clean Energy Act* is to reduce GHG emissions. Prescribed undertakings do not necessarily provide an opportunity to pursue innovative solutions, particularly in cases where the prescribed undertakings are narrowly defined or can be carried out by the utility using well established commercial technologies.

On page 17 of the FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014-2018 (FEI PBR Application), FEI stated the following:

> The Company is faced with slow customer addition growth and a decline in average use per customer despite low commodity rates in recent years…
>
> FEI will continue to focus its efforts on customer retention with a proactive approach to addressing the customer concerns before they make the decision to leave the gas distribution system…
>
> Addressing the customer growth challenges requires an approach that attracts customers by increasing preferences for natural gas use with a focus on efficient use of energy and continuing the Company's sales efforts to enhance relationships with the builder and developer community.

On page B-18 of the Application, FortisBC states: "FEI continues to experience consistent high levels of new customer attachments including record growth in the conversion market."

13.11 Please confirm, or explain otherwise, that FEI was able to achieve high levels of customer growth and load growth during the Current PBR Plan.

Response:

Confirmed.

13.11.1 If confirmed, please discuss whether the high levels of customer and load growth achieved during the Current PBR Plan term are an indication that the existing incentives and mechanisms in place were adequate to enable FEI to achieve its goals of customer retention and growth.

Response:

While FEI has sustained high levels of customer growth during the Current PBR Plan term, this is not indicative that the incentives and mechanisms in place during the term of the Current PBR Plan will be adequate for the future. The operating environment for FEI continues to become more complex and challenging, with multiple factors affecting the adoption of natural gas making it increasingly more challenging. Through the term of the MRP, FEI will need to increase its efforts to encourage the use of natural gas by investing in various initiatives to add and retain customers, which aim to keep natural gas rates low for all customers. The challenging operating environment for customer additions and natural gas load during the MRP term and the factors affecting this operating environment are discussed below.

Climate Action Plans and Initiatives

Climate actions plan, including the CleanBC Plan, the BC Energy Step code, and local government activities that strengthen their climate action initiatives, will constrain the ability for FEI to attract and retain customers over the term of the MRP. FEI anticipates pressure on the rate of new customer attachments, and challenges to customer retention and maintaining natural gas demand. Please refer to the responses to BCUC IR 1.1.1, 1.1.1.2 and 1.2.1 for a further discussion of these climate action plans.

The BC Energy Step Code provides municipalities with tools to increase the efficiency and performance of new buildings. As municipalities seek to adopt the higher levels of the Step

Code, FEI expects it will be more challenging for buildings to use traditional natural gas equipment as the Step code increases building costs and some builders may opt to install electric energy systems for space heating and water heating to help meet municipal requirements. Please refer to the response to BCUC IR 1.2.1 for further discussion.

Further, as a municipalities find means to strengthen their climate action plans and encourage emissions targets such as those described in the response to BCUC IR 1.2.1, this will reduce the adoption of natural gas appliances in new construction. As fewer natural gas appliances are installed in buildings, natural gas load will decrease and this will in turn impact the system extension test and increase the CIAC required from either builders/developers or homeowners.

As it pertains to the retention of existing customers, this group will likely be influenced by new incentives offered by the Province to switch out their gas appliance to an electric heating appliance. The Province recently announced the EfficiencyBC initiative which provides rebates to residents to assist in the conversion their existing oil, propane or natural gas appliance to an air-source heat pump. In addition, there are over ten cities/regional districts that are offering top-ups to the provincial rebate of up to $2,000. Such incentives will place pressure on the growth of FEI's conversion customers along with the retention of existing customers and load.

Slowing new Housing Construction Market

The new housing construction market is expected to soften over the term of the MRP as compared to that of the Current PBR Plan term largely due to policy and regulation changes that affect the purchase of a home, such as tightening mortgage rules, the foreign buyer's tax, and the speculation tax. This softening of the market over the period 2020 through 2024 is evident in the Conference Board of Canada Housing Starts included in response to BCUC IR 1.41.3. A softening housing market results in both fewer opportunities to install gas due to fewer homes being built, and also builders/ developers being more focused on their construction costs as they may not be guaranteed a sale of their development at a certain price point. As such, to manage their costs they may opt to install heating equipment that has a lower upfront capital cost, such as electric base boards and other electric appliances.

Increasing Construction Costs

FEI has seen rising costs in construction to install mains and services (as described in the response to BCUC IR 1.8.13) which in turn contributes to a potentially higher CIAC required from the customer for the main or service install to pass the system extension test. The impact of these will continue to be experienced throughout the MRP term. Costs pressures associated with contractor price increases, field quality assurance, and testing will continue to be managed through the MRP term (refer to BCUC IR 1.8.19). As new housing starts decline over the term of the MRP, growth opportunities shift from the new home builds to conversions where mains and services installs are typically more costly when compared to new builds, as more often than not these types of system extensions require the excavation of existing roads and sidewalks. In

addition, these conversions may be located in regions such as Vancouver Island where the terrain is rockier. As such, conversions typically require a higher CIAC than new builds such that, to maintain growth levels, additional incentives and/or mechanisms in place will be essential to assist with these challenges.

Evolving Customer Expectations

Customer retention over the MRP term will require FEI to adapt to evolving customer expectations. Evolving customer expectations include the ability for customers to be digitally connected with the providers of their services, have greater choices and options, be empowered with information, have the ability to self-manage their energy use, as well as their overall expectations for what the experience should look and feel like. Please refer to the response to BCUC IR 1.3.1 for further discussion.

FEI's efforts to attract and retain customers will need to be heightened through the MRP term to address this more complex operating environment. Additional investment and efforts will be required to actively promote the benefits and value of natural gas and in engaging with various stakeholders and customer segments to find the right energy solutions that meet their needs. Please refer to the response to BCUC IR 1.1.1 for further discussion.

13.12 Based on FEI's understanding, to what extent are the recent increases in customer attachments directly correlated to its active engagement efforts and to what extent could the increases in customer attachments be related to the price of natural gas compared to other heating alternatives? Please discuss.

Response:

A number of factors have contributed to the high levels of customer attachments including the relative price advantage of natural gas and FEI's extensive engagement with the builder/developer community, increased marketing efforts, incentives to help residents offset the cost to convert their oil or propane appliance to natural gas, as well as the adoption of common rates across the Province and an active housing market. All of these initiatives have been critical and together have played a role in the recent increases in customer attachments. The extent of the contribution from each is not possible to quantify.

14.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.4, pp. B-51 – B-54; Exhibit B-1-1, Appendix C2-1, pp. 5, 13, 20, 25, Appendix C2-4, pp. 5–6

FEI Benchmarking Study

On page 5 of Appendix C2-1, Concentric provides the list of Canadian and Pacific Northwest US natural gas utilities included in the industry peer group analysis.

In footnote 7 on page 5 of Appendix C2-1, it states that Concentric requested data from eight natural gas Canadian utilities, and received data from five of those companies.

14.1 Other than the eight natural gas Canadian utilities which Concentric requested data from, what other Canadian natural gas utilities were considered by Concentric, but ultimately excluded from the data request? As part of this response, please explain why these utilities were excluded.

Response:

The following response has been prepared by Concentric.

Other than the eight natural gas Canadian utilities discussed in footnote 7 on page 5 of Appendix C2-1, and from which Concentric requested data, Concentric also considered Heritage Gas. Concentric ultimately excluded Heritage Gas, however, due to its relatively small size (i.e., less than 7,000 customers).

14.2 Please explain why Concentric limited its study of US natural gas utilities to the Pacific Northwest region.

Response:

The choice of comparable utilities to include in the FEI and FBC benchmarking studies is an outcome of the collaborative nature of the benchmarking study where the BCUC directed FortisBC to consult with interested stakeholders with the objectives to select a mutually acceptable consultant to conduct the benchmarking study and to reach an agreement on the Terms of Reference.

For comparable utilities to include, Canadian Electric and Natural Gas Distribution utilities were the primary group chosen for the studies. During the stakeholder consultation process, the Irrigation Ratepayers Group asked to also include utilities in the Pacific Northwest (Washington

State) as part of the study or provide rationale for excluding them. As a result of this feedback, which was included in the communication to stakeholders as part of the consultation process, comparable US natural gas and electric utilities in the Pacific Northwest were included in the benchmarking studies.

Prior to finalizing the Terms of Reference for the RFP process, FortisBC representatives met with BCUC staff in November 2017 to review stakeholder comments and advise of the proposed Terms of Reference, including the utilities to include in the studies.

The final choice of the comparable Pacific Northwest utilities to include in the studies was determined in discussion with Concentric.

14.3 Of the five Canadian and eight US natural gas utilities listed in Figure 1, please explain if any of these utilities were operating under a PBR or MRP regime during the period of the benchmarking study.

Response:

The following response has been prepared by Concentric.

Of the five Canadian and eight US natural gas utilities listed in Figure 1 of Appendix C2-1, the companies operating under a PBR or MRP during the period of the benchmarking study were ATCO Gas Distribution, Enbridge Gas Distribution, Energir,[18] Union Gas, and Puget Sound Energy.[19]

14.4 Please explain if the type of rate-setting approach (i.e. PBR, MRP, Cost of Service) was a consideration for Concentric when selecting the utilities for the study, and if not, why not.

Response:

The following response has been prepared by Concentric.

[18] Energir used a performance incentive mechanism from October 2007 to September 2012.

[19] Puget Sound Energy operated under a multi-year rate plan from 2013 to 2017 with decoupling and earnings sharing provisions.

While all the utilities selected for inclusion in the peer group were rate-regulated, Concentric did not further differentiate the peer companies' type of rate-setting approach as a selection criterion. As stated on Page 4 of Appendix C2-1, the primary criteria used to determine the peer group compositions were the type of operations of each company, the geography of each utility, and whether each utility was rate-regulated. As further stated on Page 4 of Appendix C2-1, those criteria were determined to allow for a peer group that would provide a sufficiently broad perspective for industry comparisons. While the type of rate-setting approach was not used as an additional screening criterion, as a practical matter, four out of the five utilities in the Canadian proxy group companies operated under some type of PBR during the study period.

Page 6 of the November 13, 2018 minutes to the Benchmarking Study Workshop states: "Starting in 2014, FEI moved into a period of sustained growth and the associated capital expenditures to attach unprecedented numbers of new customers and undertake system improvements to address capacity concerns."

On page 13 of Appendix C2-1, Concentric states that FEI's net plant has increased "modestly" over the period studied (i.e. 2012 through 2017) on a nominal basis and has remained flat on a real basis.

14.5 Please explain the modest net plant increases described by Concentric in the Benchmarking Study in the context of FortisBC's statements in the workshop minutes regarding sustained growth.

Response:

The following response has been prepared by Concentric:

As discussed on page 6 of Appendix C2-1, and further illustrated in Figure 8 of Appendix C2-1 (page 14), FEI's net plant increased on a nominal basis by a compound annual growth rate of 1.36 percent over the period studied, and remained flat on a real basis based on a five-year average annual increase in the Consumer Price Index of 1.39 percent.

The following comments have been prepared by FortisBC:

FortisBC's comments in the Benchmarking Study Workshop referring to FEI's higher growth and sustainment capital expenditures were in response to a request for FortisBC to comment on the phase that the capital spend cycle was at. FEI's response discussed the recent and continuing period of sustained growth in capital spending. FEI's net plant changes are increased by capital expenditures driven by this sustained growth, but the impact of the sustained growth in capital expenditures is not as clearly seen because net plant balances also decreased by depreciation

expense, and the asset base to which the changes are applied is significantly larger than the annual capital expenditures. Regardless, both high levels of growth capital and higher sustainment capital do contribute to the modest increase in net plant noted by Concentric.

On page 20 of Appendix C2-1, Concentric states the following:

> Compared to the Canadian utilities, FEI was above the median…on a net distribution plant per customer and net distribution plant per employee basis for the years 2012 through 2016, and approximately at the median in 2017. FEI's relatively flat level of net plant per customer over the course of the study period…eased this differential, whereas the Canadian peer group…experienced rising net plant per customer…
>
> In comparison to the Pacific Northwest U.S. peer group, FEI is substantially above the group median on a net plant per customer basis.

14.6 Please discuss the likely reasons why FEI is above the median on a net distribution plant per customer and net distribution plant per employee basis compared to both the Canadian and US peer group utilities.

Response:

The following response has been prepared by Concentric.

Compared to the Canadian utilities, FEI was above the median on a net distribution plant per customer and net distribution plant per employee basis for the years 2012 through 2016, and approximately at the median in 2017. While the benchmarking data provides useful information regarding relative performance, it does not, however, provide the cause of that differential, or why that differential was eliminated over time, other than if specific contributors can be identified. For instance, Appendix C2-1 noted, on page 20, that the compound annual growth rate for the Canadian peer group was driven heavily by two of the peer group companies, which had growth in net plant that was significantly greater than the other companies in the peer group.

In comparison to the Pacific Northwest U.S. peer group, FEI was substantially above the group median on a net plant per customer basis, while FEI was substantially below the Pacific Northwest U.S. utilities' median net plant per employee. The net plant per customer result was driven by the net plant-per-customer of three of the utilities in the Pacific Northwest U.S. peer group, all of which had lower net plant-per-customer than each of the Canadian peer group companies in every year of the period studied. While the Pacific Northwest U.S. utilities' median

net plant per employee was noticeably above FEI and the Canadian peer group, that result can be attributed to the fact that net plant per employee data was only available for two of the Pacific Northwest U.S. utilities, and both of those utilities were on the high end in terms of the range of net plant per customer.

Some factors that impact net plant per customer include:

- Age of the distribution system - newer systems are generally more costly on a net plant basis than older depreciated systems
- Customer density – rural and less dense systems typically have higher per customer net plant, although we can see some of this relationship offset in higher cost urban areas
- Customer mix – a high percentage of residential customers generally implies that, all else being equal, that utility may experience higher costs than utilities with fewer residential customers due to the additional capital investment required to serve a larger proportion of smaller customers.

14.6.1 How have these results informed FortisBC's design of the proposed MRP, if at all?

Response:

As noted by Concentric in the responses to BCUC IRs 1.14.6 and 1.15.4.1, while the benchmarking data provides useful information regarding relative performance, it does not provide the cause of that differential, or why that differential changes over time, other than if specific contributors can be identified. Concentric notes also that the standard benchmarking comparison is a relative one, and therefore does not offer insights into performance in an absolute sense.

Recognizing this context for the interpretation of the benchmarking study results and that FEI's net distribution plant (capital investment) results are at or above the median in the benchmarking study, FEI has designed its MRP with a continued focus on efficient operations, as stated in Section C8.2.1 of the Application. FortisBC's focus is not only on reducing costs, but on maximizing efficiency more broadly. The proposed traditional incentive for capital spending is designed to contain Regular capital spending 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.

Please also refer to the response to BCUC IR 1.16.1.

14.7 Please discuss whether a key contributing factor to the easing of the differential in net plant per customer over the course of the benchmarking study period was FEI's growth in customers.

Response:

The following response has been prepared by Concentric.

The data does not indicate that FEI's growth in customers was a key contributing factor to the easing of the differential noted in the request. The 5-year compound annual growth rate (CAGR) for FEI's customers was 1.21 percent, while the 5-year CAGR for FEI's net plant was 1.91 percent. The 5-year CAGR for the Canadian peer group companies' (excluding FEI) customers ranged from 0.90 percent to 1.82 percent, similar to FEI's. On the other hand, the 5-year CAGR for the Canadian peer group companies' (excluding FEI) net plant ranged from 3.49 percent to 10.06 percent, significantly higher than FEI's, indicating that the easing of the differential was driven more by the growth in net plant of the peer companies as compared to FEI than to FEI's relative growth in customers.

14.8 Did FEI's net plant per employee differential also ease during the study period?

Response:

The following response has been prepared by Concentric.

Yes, the differential between FEI's and the peer group's net plant per employee also eased towards the end of the period studied (i.e., in 2016 and 2017). The data, however, do not provide a clear indication for the cause of that narrowed differential. Specifically, while the net plant compound annual growth rates (CAGRs) were the same as those described in the response to BCUC IR 1.14.7, the employee CAGRs do not provide a clear explanation for the trends observed. Specifically, FEI's 5-year CAGR for employees was (0.39 percent), while the 5-year CAGRs for the Canadian peer group companies' (excluding FEI) employees ranged from (4.16 percent) to 0.71 percent.

14.8.1 If yes, how did this compare to the net plant per customer differential.

Response:

Please refer to the response to BCUC IR 1.14.8.

14.8.2 If no, please explain the likely reasons why not.

Response:

Please refer to the response to BCUC IR 1.14.8.

Figures 20 and 21 on page 25 of Appendix C2-1 provide data on customer care expense per customer and customer care expense per terrajoule (TJ), respectively.

14.9 With reference to FEI's specific operational circumstances, please explain the causes for the decrease in customer care expense per customer and customer care expense per TJ between 2013 and 2017.

Response:

Customer Care Expense per Customer (Figure 20)

The decrease in customer care expense per customer between 2013 and 2017 was due to reduced O&M in customer care expense from 2013 to 2016 and from an increase in customers from 2013 to 2017.

Reduced O&M for customer care expense over the 2013 to 2017 period was derived from the efficiencies found after go-live of the in-sourcing of customer care in 2012. Some of these saving are from management reorganization and reductions in staffing related to Project Blue Pencil. In addition, fluctuations in the expense per customer also reflect varying call volumes from year to year.

Customer Care Expense per TJ (Figure 21)

Similar to above, the decrease in customer care expense per TJ between 2013 and 2017 was due to reduced O&M in customer care expense from 2013 to 2017 and from an increase in volume sold from 2016 to 2017.

15.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1, Section B2.4, pp. B-54 – B-57, Section B2.6.3, p. B-73; Exhibit B-1-1, Appendix C2-2, pp. 5, 10, 14, 19–20, 23–24, 36–39

FBC Benchmarking Study

On page 5 of Appendix C2-2, Concentric provides the list of Canadian and Pacific Northwest US electric utilities included in the industry peer group analysis.

In footnote 7 on page 5 of Appendix C2-2, it states that Concentric requested data from 15 electric Canadian utilities, and received data from nine of those companies.

15.1 Other than the 15 electric Canadian utilities which Concentric requested data from, what other Canadian electric utilities were considered by Concentric but ultimately excluded from the data request? As part of this response, please explain why these utilities were excluded.

Response:

The following response has been prepared by Concentric.

There were no other Canadian electric utilities considered by Concentric for purposes of the FBC benchmarking study.

15.2 Please explain why Concentric limited its study of US electric utilities to the Pacific Northwest region.

Response:

Please refer to the response to BCUC IR 1.14.2.

15.3 Of the nine Canadian and five US electric utilities listed in Figure 1, please explain if any of these utilities were operating under a PBR or MRP regime during the period of the benchmarking study.

Response:

The following response has been prepared by Concentric.

Of the nine Canadian and five US electric utilities listed in Figure 1 of Appendix C2-2, the companies operating under some sort of PBR or MRP during the period of the benchmarking study were ATCO Electric Distribution, Fortis Alberta, ENMAX, EPCOR, Hydro Quebec Distribution, Hydro Ottawa, and Puget Sound Energy.[20]

15.4 Please explain if the type of rate-setting approach (i.e. PBR, MRP, Cost of Service) was a consideration for Concentric when selecting the utilities for the study, and if not, why not.

Response:

The following response has been prepared by Concentric.

While all the utilities selected for inclusion in the peer group were rate-regulated, Concentric did not further differentiate the peer companies' type of rate-setting approach as a selection criterion. As stated on Page 4 of Appendix C2-2, the primary criteria used to determine the peer group compositions were the type of operations of each company, the geography of each utility, and whether each utility was rate-regulated. As further stated on Page 4 of Appendix C2-2, those criteria were determined to allow for a peer group that would provide a sufficiently broad perspective for industry comparisons. While the type of rate-setting approach was not used as an additional screening criterion, as a practical matter, six out of the nine utilities in the Canadian proxy group operate under some type of PBR/MRP.

In Section B2.6.3 of the Application, FortisBC describes the US jurisdictions of California and New York which it states are considering and/or adopting "alternative incentive frameworks".

In footnote 92 on page B-73 of Section B2.6.3, FortisBC states that in addition to New York and California, other US jurisdictions including Minnesota, Rhode Island, Illinois,

[20] Puget Sound Energy operated under a multi-year rate plan from 2013 to 2017 with decoupling and earnings sharing provisions.

Ohio and Hawaii are "also in the process of designing or implementing similar alternative incentive frameworks."

15.5 Please clarify if the above jurisdictions discussed in Section B2.6.3 of the Application include both natural gas and electric utilities or just electric utilities.

Response:

FortisBC assumes that the question asks if the above-mentioned jurisdictions include "alternative incentive frameworks" for both natural gas and electric utilities or just electric utilities. The majority of alternative incentive frameworks identified in FortisBC's research relate to the electric utilities only.

Nevertheless, as mentioned in the response to BCUC IR 1.18.1, natural gas utilities are catching up with their electric counterparts and have started to propose targeted incentives as well. For more information regarding the initiatives in the natural gas industry please refer to the response to BCUC IR 1.18.1.

Further, some of these jurisdictions have targeted incentive frameworks that apply to both natural gas and electric utilities. In Illinois, for example, the Illinois Commerce Commission (ICC) initiated a proceeding (applied to both natural gas and electric utilities) to remove the disparity between adopting on-premise versus cloud-based computing systems where a disincentive existed for utilities to invest in new technology. Specifically, the ICC approved a new regulatory treatment in their decision (17-0855) to level the playing field between the two options by capitalizing the costs associated with cloud-based computing solutions.

15.6 Please explain if any of the utilities included in the benchmarking studies (either FEI or FBC's) are the jurisdictions designing or implementing "alternative incentive frameworks" discussed in Section B2.6.3.

Response:

The following response has been prepared by Concentric.

PacifiCorp, which was included in the peer group in the FBC benchmarking study, operates in California as well as five other states.[21] No other company in either the FEI or FBC peer groups operates in the jurisdictions provided in the request.

The following comments have been provided by FortisBC.

The purpose of Concentric's benchmarking study was to provide the BCUC with information on FEI's and FBC's cost efficiency and service quality performance relative to other utilities (refer to page B-48 of Application) and not to compare alternative incentive frameworks in different jurisdictions.

FortisBC's jurisdictional comparison study (Appendix C4-2 of the Application) provides a detailed review of alternative incentive frameworks approved in New York and California. The other jurisdictions mentioned above are all the jurisdictions referred to by Dr. Makholm in his recent article published in the Electricity Journal (Appendix C4-1).

15.6.1 If yes, please explain how the results from the benchmarking studies may or may not support FortisBC's proposals for targeted incentives in the MRPs.

Response:

Please refer to the response to BCUC IR 1.15.6.

15.6.2 If no, please explain why not, and explain whether, in consideration of FortisBC's proposals for targeted incentives in the MRPs, inclusion of these jurisdictions as part of the benchmarking studies may have helped inform the design of the proposed MRPs.

Response:

Please refer to the response to BCUC IR 1.15.6.

[21] Other states of operations are Idaho, Oregon, Utah, Washington, and Wyoming.

On page 10 of Appendix C2-2, Concentric states the following:

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

15.7 Please clarify if Concentric also excluded generation and transmission net plant from its analyses.

Response:

The following response has been prepared by Concentric.

Yes, Concentric excluded generation and transmission plant from its comparative net plant metrics (i.e., net plant per customer, employee, and kilometer of distribution mains).

15.8 Please discuss the implications (beyond controlling the risk of skewed results) that excluding generation and transmission from the analyses may have on the study results.

Response:

The following response has been prepared by Concentric.

The major implication of excluding certain functions (e.g., generation and transmission) from the analysis is that the relative performance associated with those functions is not captured in the benchmarking results. That implication, however, was outweighed by the fact that the distribution-only segment provided the most meaningful benchmark, because of significant differences between the scope of peer companies' transmission and generation facilities, as well as differences between the level of customer care services provided across the Canadian utilities. Use of the distribution segment also ensured the inclusion of the greatest number of peer group companies, providing for more reliable benchmarking results. Lastly, to ensure that

the generation and transmission functions were reflected in the study, Concentric analyzed total O&M expense and total net plant (both including transmission) in the stand-alone financial analysis of FBC.

15.9 Please clarify if Figures 7 and 8 on page 14 of Appendix C2-2 include generation and transmission O&M and net plant.

Response:

The following response has been prepared by Concentric.

Yes, Figures 7 and 8 on page 14 of Appendix C2-2 include generation and transmission O&M and net plant.

On page 20 of Appendix C2-2, Concentric states: "Unlike OM&A, FBC's net plant on a per-unit basis may also be impacted by its lack of scale compared to its peers."

15.10 Please further explain the above statement. Also, please explain why FBC's lack of scale would have a greater impact on net plant than on OM&A.

Response:

The following response has been prepared by Concentric.

As discussed on page 11 of Appendix C2-2, FBC is the second smallest Canadian utility among the peer group analyzed in the study, and second smallest overall among the Canadian and Pacific Northwest U.S. peer groups. As such, to the extent scale economies are operative, FBC would be expected to be among the least efficient of its electric peers. The statement cited in the request was not a comparison of the impacts of scale on net plant versus OM&A, but rather was an observation that the impacts of scale may be displayed in FBC's relative net plant performance, while not appearing to be displayed in FBC's relative OM&A performance.

15.11 Please further explain and define Concentric's assessment of FBC's "lack of scale compared to its peers" and provide context for this assessment.

Response:

The following response has been prepared by Concentric.

On pages 11-12 of Appendix C2-2, Concentric compared FBC's customer count and volume sold with other utilities in the peer groups. As stated in the report, in terms of the number of customers served, FBC is the second smallest Canadian utility among the peer group and second smallest overall among the Canadian and Pacific Northwest U.S. peer groups. Similarly, in terms of volumes sold, FBC is the second smallest Canadian utility among the peer group and second smallest overall among the Canadian and Pacific Northwest U.S. peer groups.

On pages 19-20 of Appendix C2-2, Concentric states the following:

> Compared to the Canadian and Pacific Northwest U.S. utilities in the peer groups…FBC was well above the median on a net plant-per-customer basis and net plant-per-kilometre of distribution lines basis for all the years in the study period, and above the median in all years except 2017 (where it was at the median) on a net plant-per-employee basis. FBC went through a period of significant capital expenditures from 2005 through 2012, resulting in an elevated level of gross plant that has not been significantly depreciated.

15.12 Based on the statement in the above preamble, does Concentric consider the primary factor in FBC's significantly higher net plant per unit to be FBC's capital spending from 2005 through 2012?

Response:

The following response has been prepared by Concentric.

While benchmarking data provides useful information regarding relative performance, it does not provide the cause of that differential other than if specific contributors can be identified. In this case, FBC's capital spending from 2005 through 2012 appears to be a significant contributor to the differentials noted between FBC and the peer groups.

15.12.1 What other factors have likely contributed to FBC's net plant being higher than the comparator utilities on a net plant per unit basis? Please discuss.

Response:

The following response has been prepared by Concentric.

One other factor that Concentric identified in the study is economies of scale. Specifically, as discussed in the study, the lack of scale of FBC compared to the peer companies is a potential factor contributing to net plant per unit being greater than the peer company medians.

Figures 20 and 21 on pages 23 and 24, respectively, of Appendix C2-2 show the customer care expense per customer and the customer care expense per megawatt-hour (MWh).

15.13 Please explain why FBC's customer care expense per customer and MWh decreased significantly between 2014 and 2016.

Response:

Customer Care Expense per Customer (Figure 20)

The decrease in customer care expense per customer between 2014 and 2016 was due to reduced O&M costs in FBC's customer care expense from 2015 to 2016 and from an increase in customers from 2014 to 2016. Reduced O&M for customer care expense over the 2014 to 2016 period are from efficiencies gained from optimizing staffing during peak times and from one-time savings due to vacancies.

Customer Care Expense per MWh (Figure 21)

Similar to above, the decrease in customer care expense per MWh between 2014 and 2016 was due to reduced O&M in FBC's customer care expense from 2015 to 2016 and from an increase in volume sold in 2016.

Concentric summarizes FBC's benchmarking results on pages 36 to 39 of Appendix C2-2 and provides the benchmarking analyses summary in Figure 36.

15.14 In consideration of the results in Figure 36 of Appendix C2-2, please provide an overall assessment of FBC's performance in comparison to the utilities included in the benchmarking studies. Please clearly explain the rationale for this response.

Response:

The following response has been prepared by Concentric.

FBC performed better than the median at the broadest expense level analyzed (i.e., distribution O&M plus total A&G) on a per customer, per volume, per employee, and per kilometre of distribution line basis, as well at the A&G expense level on both a per-customer and per-volume basis. FBC performed less favorably, on a relative basis, on a net plant per customer, employee, and kilometre of distribution line basis, interest expense per customer basis, and customer care metrics. In terms of reliability, customer service, and other metrics, FBC performed at or better than the peer group median on three of the metrics in all years (emergency response time, total DSM per customer, and DSM incentives only per customer); at or better than the median on three metrics for most years (SAIDI, SAIFI, and DSM expenditures excluding incentives per customer); and at or below the median on two metrics for most years (TSF-non-emergency and FCR).

15.14.1 Based on the benchmarking study results, what are the key areas of improvement for FBC and how might these improvements be achieved during the proposed MRP term? Please discuss.

Response:

The following response has been prepared by Concentric.

As discussed in Appendix C2-2, benchmarking provides a view into industry performance and provides perspective for regulators and stakeholders. Benchmarking does, however, have limitations, including its inability to quantify causal relationships between operating circumstances and costs, and between inputs and outputs. Further, the standard benchmarking comparison is a relative one, and therefore does not offer insights into optimal performance in an absolute sense.

While not dispositive of the question regarding areas of needed improvement, there are certain areas in which FBC performed worse than the industry median. Specifically, on a relative basis, and as discussed in the response to BCUC IR 1.15.14, FBC performed less favorably than the peer group 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 performance relative to the peer groups, FBC performed at or below the median on two metrics for most years (TSF-non-emergency and FCR).

Figure 36 on page 37 of Appendix C2-2 shows that FBC performed significantly less favourably than the median in distribution net plant per customer, which ranged from +127% in 2012 to +98% in 2017, and in distribution net plant per km distribution line, which ranged from +73% in 2017 to +42% in 2012.

15.15 Given the significant percentages above the median for these two metrics, what conclusions can be drawn, if any, regarding FBC's level of capital spending? Please discuss.

Response:

The following response has been prepared by Concentric.

As discussed in the study, Concentric drew two main conclusions regarding FBC's relative net plant performance. First, FBC went through a period of significant capital expenditures from 2005 through 2012, resulting in an elevated level of gross plant that has not been significantly depreciated. Second, FBC's net plant on a per-unit basis may also be impacted by its lack of scale compared to its peers.

15.16 What are the likely reasons for the distribution net plant per customer to be consistently trending downwards between 2012 and 2017 while the distribution net plant per km distribution line has been trending upwards (with the exception of 2016)? Please discuss.

Response:

The following response has been prepared by Concentric.

As shown in Figures 13 and 15 of Appendix C2-2, the net plant per customer and per kilometer both trended upwards over the period studied, although at different rates. Specifically, the compound annual growth rate (CAGR) for net plant per customer was 1.85 percent while the CAGR for net plant per kilometre of distribution line was 4.28 percent. The CAGR for customers was 3.46 percent while the CAGR for kilometres of distribution lines was 1.06 percent, which may explain some of the observed difference in growth rates between distribution net plant per customer and distribution net plant per kilometre of distribution line.

16.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-1-1, Appendix C2-4, p. 5

Benchmarking Study Results

Page 5 of the November 13, 2018 minutes to the Benchmarking Study Workshop (Appendix C2-4) includes the following:

> A question was asked as to how the benchmarking study would be used in the context of the company's next MRP application. FortisBC commented that consistent with the BCUC directive, the Benchmarking Study along with other considerations were intended to inform the BCUC's decision on the determination of the X-Factor for its next MRP.

16.1 Please explain how the results of the benchmarking studies for FEI and FBC provided support for or helped to inform the proposal to not include a productivity factor for either FEI or FBC in the proposed MRP.

Response:

In the 2014 PBR Decision, the BCUC stated that there was no evidence on the record to suggest that FEI and FBC are less or more efficient than the industry and therefore, it had to use its judgement to set stretch factor values of +0.2 and +0.1 percent for FEI and FBC, respectively. The BCUC further directed the utilities to file benchmarking studies before the end of the PBR term to inform its X-Factor value determination in any future PBR plan[22]:

> The Commission Panel agrees with ICG that there is a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. 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.

The benchmarking analysis performed by Concentric can be used to estimate the relative cost efficiency of a utility compared to its peer group. Similarly, the benchmarking of non-financial metrics (service quality indicators) can be used to consider the "safety and reliability" aspects of the utility operations that are not incorporated in cost efficiency benchmarking.

[22] BCUC Decision G-138-14, p.82.

As discussed in Section B2.4.3.1 of the Application, FEI outperformed or met its peer group median in the majority of the financial metrics studied. In particular, FEI's O&M and total A&G unit cost metrics outperformed its peer group in almost all of the years studied. The benchmarking analysis therefore indicates FEI's relative efficiency compared to its peers (particularly for O&M metrics) and indicates that an additional "efficiency factor" is not warranted as FEI has been operating under PBR for a number of years and is already relatively more efficient than the median of its peer companies in the majority of the benchmarked financial metrics. The benchmarking of FEI's non-financial metrics (customer service and reliability metrics) indicates that FEI performed at or better than the peer group median in all of, or the majority of in some cases, the years for six metrics while performing at or below the median for only two metrics. FEI's relative superior performance on these metrics indicates that it did not achieve its relative cost efficiency at the expense of lower service quality and therefore confirms that a negative adjustment to the O&M index is not warranted.

Similarly, as discussed in Section B2.4.3.2 of the Application, FBC's O&M and total A&G unit cost metrics performed better than the median in almost all the years studied. The benchmarking analysis therefore confirms FBC's relative operational efficiency compared to its peers (for O&M metrics) and suggests that an additional "efficiency factor" to its O&M index is not warranted as FBC has been operating under PBR for a number of years and is already relatively more efficient than the median of its peer companies in O&M related metrics. The benchmarking of FBC's non-financial metrics also indicates FBC's superior performance relative to its peers in the majority of the years studied for seven out of nine metrics studied which confirms that a negative adjustment to the O&M index is not warranted.

17.0 Reference: REVIEW OF OTHER JURISDICTIONS

Exhibit B-1, Sections B2.6, C1.4.2, pp. B-69 – B-73, C-9; Exhibit B-1-1, Appendix C4-2, pp. 1–2, 32

Features of Indexed-based MRPs in Canada

On page 1 of Appendix C4-2, FortisBC states the following:

> This study relies on publicly available information, which includes regulatory filings and reports available in the utility regulators' websites.
>
> FortisBC notes that all incentive frameworks presented in this report are designed to promote continuous efficiency focus and/or to achieve targeted outcomes while ensuring that service quality requirements and government policy objectives are met; and to create an efficient regulatory process for the period of the MRP, allowing the Utilities to effectively manage business priorities and increase innovative solutions to the Utilities' challenges.

17.1 Please confirm, or explain otherwise, that the jurisdictional comparison report provided as Appendix C4-2 to the Application was prepared by FortisBC staff, as opposed to an independent consultant.

Response:

Confirmed. The information provided in the study can be verified by referencing the publicly available sources cited in the report.

17.2 Please clarify if the paragraph on page 1 of Appendix C4-2 provided in the above preamble regarding FortisBC's comments on the incentive frameworks is a statement taken from the utility regulators' filings and reports or if this is FortisBC's analysis/summary of the information.

Response:

The referenced paragraph is a summary of FortisBC's analysis and alludes to the fact that, despite similar objectives, there is no "one size fit all" incentive model than can work for all utilities. For reference, the complete paragraph from page 1 of Appendix C4-2, as cited in the preamble above, is as follows:

> FortisBC notes that all incentive frameworks presented in this report are designed to promote continuous efficiency focus and/or to achieve targeted outcomes while ensuring that service quality requirements and government policy objectives are met; and to create an efficient regulatory process for the period of the MRP, allowing the Utilities to effectively manage business priorities and increase innovative solutions to the Utilities' challenges. Nevertheless, within these common principles, each jurisdiction has tailored the plans to fit its specific circumstances. This supports the popular belief that there is no one "right" incentive model and that the framework adopted for each utility should be in keeping with their specific circumstances and their history with incentive regulation. In other words, while MRPs in various jurisdictions may share many common features, the overall package is tailored to fit the circumstances of each utility.

Similar statements from regulators corroborate FortisBC's comment. For instance, as stated on page B-67 of the Application, the following statement from the OEB conveys the same message:

> 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.

Table B2-9 on pages B-70 and B-71 of the Application provides a Canadian jurisdictional comparison of MRPs.

On pages B-72 and B-73 of the Application, FortisBC states that it draws a number of high-level conclusions from Table B2-9, including the following:

> 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.

17.3 Please explain why, given the prevalence of the inclusion of an X-Factor in the other Canadian jurisdictions' MRPs, FortisBC considers it reasonable not to include an X-Factor in its proposed MRPs.

Response:

FortisBC's proposal to not recommend an X-Factor value for its index-based formulas can be expressed as proposing an implied productivity factor of zero percent. A zero percent X-Factor is higher than what the majority of utility experts in other jurisdictions have proposed and is not at odds with what has been approved by regulators in other jurisdictions. This can be seen from the table provided in BCUC IR 1.13.2, which shows that the majority of utilities in Canada have proposed negative productivity factors. Further, the OEB has approved zero percent productivity factors with additional 0.0 to 0.6 percent stretch factors for the case of electric utilities and 0.3 percent stretch factor for Union Gas and Enbridge Gas Distribution amalgamated price cap plans.

17.4 Please specifically address the reasonableness of including an X-Factor of between 0.3 and 0.6 percent in FortisBC's MRPs.

Response:

FortisBC's proposed implied zero percent X-Factor value is reasonable and, FortisBC's X-Factor value should be lower than the approved X-Factor (inclusive of any stretch factor) in other Canadian jurisdictions.

The higher X-Factor value in other jurisdictions may be warranted due to their specific circumstances. The Alberta utilities in their first generation PBR had significantly higher realized ROEs than their approved ROE to the point that two major utilities, ATCO Gas and ATCO Electric, both triggered the off-ramp provisions of their plans (set at 300 bps for two consecutive years and 500 bps in one year). This may indicate higher efficiency opportunities in that jurisdiction. Similarly, the amalgamation of Enbridge Gas Distribution and Union Gas will provide the amalgamated utility with additional cost saving opportunities that are not available to FEI or FBC. Finally, Hydro Quebec Distribution is experiencing its first generation revenue cap model which may indicate higher productivity opportunities due to the existence of low-hanging fruit

and justify the higher 0.3 percent X-Factor. None of these circumstances is present for FortisBC, which has been under PBR plans for longer than any other utilities in Canada. Concentric's Benchmarking Studies confirm that FEI and FBC's operating costs are lower than the median of their peer groups.

Please also refer to the response to BCUC IR 1.13.2.

17.5 If the BCUC were to determine that an X-Factor was required as part of FEI and FBC's MRPs, please explain how FortisBC would propose that the BCUC assess the appropriate quantum of an X-Factor and whether the same X-Factor should be considered for both FEI and FBC (and why).

Response:

FortisBC did not conduct a productivity factor study for the following reasons:

1. Increased importance of regulatory judgement for X-Factor determination:

   As explained in the response to BCUC IR 1.13.2, the review of recent PBR decisions in other jurisdictions indicates a move away from a pure Total Factor Productivity (TFP) approach to an increased application of regulatory judgment for X-Factor determination. This means that experts and regulators are giving less weight to the results of TFP studies and applying more judgment to derive the final proposed or approved X-Factor value. For more information on this issue, please refer to the response to BCUC IR 1.13.2.

2. Availability of recent industry productivity study results in other jurisdictions:

   The list of qualified and experienced productivity experts is limited with five or six experts having an almost total oligopoly on the TFP study market in Canada. If FortisBC had decided to conduct a TFP study, both utilities and interveners would have likely retained one of the experts that has recently filed TFP evidence in other jurisdictions and their evidence would have shown the same range of TFP results estimated by these experts in those jurisdictions.

3. Concentric's performance benchmarking study:

   In addition to TFP studies in other jurisdictions, Concentric's utility performance benchmarking study can be used to inform the BCUC's X-Factor decision. Pursuant to BCUC's 2014 PBR Decisions, FEI and FBC retained the services of Concentric to conduct a benchmarking study of the utilities' financial and non-financial performance

during the PBR term. BCUC directed FortisBC to conduct this study to inform its decision for future X-Factor determination. Therefore, the results of this study along with the results of the TFP studies and approved X-Factor values in other jurisdictions, can be used as an important input to help BCUC to make an informed judgment regarding the appropriate X-Factor value. The unit cost benchmarking results indicates that establishing an additional efficiency factor for O&M indexing formulas is not warranted as both FEI and FBC have been operating under PBR for a number of years and are relatively more efficient than the median of their peer companies in all the O&M metrics.

4. Significant complexity of TFP studies:

FortisBC agrees with interveners that the TFP studies are very technical and complicated, and are particularly difficult for utilities or interveners to understand. In other words, TFP studies, especially those done through econometric models, are like black boxes where utilities and interveners do not have a full understanding of the computations and models used, and rather can only discuss the inputs and outputs of the models. This issue was raised by CEC in its final argument in the Current PBR proceeding and discussed in the BCUC's decision:

> The Panel notes the submission of CEC that "the Commission has a serious problem with the evidence. The differences of opinion are not straight forward and understandable but are tied into esoteric economic theory and debates about methodology and assumptions, for which only PhD's seem to have perfunctory conclusions" and that "one of the most serious questions for the Commission to resolve is whether or not it is really suitable to impose this morass of complicated debate into the rate making process." (CEC PBR Final Argument, p. 57) We find CEC's comments curious, given the fact that it is referring, at least in part, to its own witness. To this, Fortis replies that "The Commission is capable of weighing the expert evidence and coming to a considered decision, and should do so." (Fortis PBR Reply, p. 64). The Panel agrees with Fortis.

FortisBC's comment as referred to by the BCUC in the above quote does not argue against CEC's statement, but rather relates to the fact that at that stage of proceeding both the utilities and interveners had already retained TFP experts and the TFP studies were already filed and a significant amount of time and money were already spent to discuss and analyze these studies as much as possible and therefore, despite the complexity of evidence, it was time for the BCUC to use its best judgement and make a decision.

FortisBC also notes that during its consultation with interveners for the benchmarking study, some commented that PBR is complicated. FortisBC believes that a significant

portion of this complexity relates to the TFP studies and therefore using the judgement-based approach may help to mitigate some of the interveners' concern in this regard.

5. Regulatory burden and cost:

   A review of the 2014-2018 PBR proceeding indicates that, due to their inherit complexity (as explained above), the TFP studies used up a significant amount of regulatory resources. Fifty-six pages of the BCUC's 2014 PBR decision relates to the determination of the X-Factor. Of the seven days of oral hearing, almost two full days were completely focused on the experts' TFP evidence and/or rebuttal. Considering the costs of expert testimonies in the previous PBR proceeding and the current less favourable exchange rate, FortisBC estimates that its proposed approach to X-Factor determination can save in the order of $500 thousand in related expenses.

As explained in the response to BCUC IR 1.13.2, the BCUC can use a number of inputs to inform its X-Factor determination. These include a review of recent testimonies filed by well-known productivity experts in other jurisdictions as well as the decisions of regulators regarding the X-Factor determination (a summary of X-Factor decisions in Alberta, Ontario and Quebec is presented in Appendix C4-2 of the Application), as well as an analysis of the Utilities' performance under the Current PBR Plan informed by the benchmarking studies that were filed.

Can a common productivity factor apply to both natural gas and electric utilities?

As evidenced by the zero percent implied X-Factor proposed for both FEI and FBC, FortisBC believes that a common X-Factor value for electric and natural gas utilities is appropriate. This is supported by the proximity of the approved X-Factor amounts in different jurisdictions for both electric and natural gas utilities.

The issue of applicability of productivity studies to both natural gas and electric utilities was studied in length in the AUC's first generation PBR decision. The data used in the AUC's consultant evidence (Dr. Makholm of NERA) was based on the distribution portion of the electric companies, whether standalone or combination electric/gas companies (NERA indicated that its study did not include data for standalone gas companies, since it was not aware of a readily available data source that would permit a comparably transparent TFP study for standalone gas companies). After reviewing NERA's evidence as well as utilities' and interveners' comments, the AUC decided that the results of NERA's study can be applied to both electric and natural gas utilities[23]:

> Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements

[23] AUC Decision 2012-237; pp. 78-79.

> between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available …
>
> Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies.

The AUC made a similar determination in its second generation PBR decision as well:[24]

> Finally, all parties in this proceeding indicated a common X factor, based on their preferred TFP growth number, could be applied to both gas and electric utilities.

On page 32 of Appendix C4-2, FortisBC states that Hydro Quebec Distribution (HQD) "determined that a 0.75 multiplier should be applied to the growth factor to account for the fixed costs that may not change in the short or medium term with the growth in number of customers."

On page C-9 of the Application, FortisBC states the following:

> 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.

17.6 Please confirm, or explain otherwise, that Hydro Quebec is the only jurisdiction in Table B2-9 of the Application which includes a growth factor, and that the growth factor is only applicable to O&M.

Response:

Not confirmed. Hydro Quebec Distribution is the only distributor in our jurisdictional review study that applies a multiplier of 0.75 to its growth factor. Other utilities in other jurisdictions have

[24] AUC Decision 20414-D01-2016; P.44.

growth factors that are either embedded in or implicit in their formulas and reflect 100 percent of changes to their growth factor. For instance, under price cap regulation in Ontario and Alberta, the increased number of customers is fully reflected in utility revenues since the same price cap applies to both new and old customers (that is, a higher customer number leads to higher consumption and higher revenues through billing determinants). Similarly, under Alberta's revenue per customer cap for natural gas utilities, the revenue is calculated as the revenue per customer multiplied by number of customers. As the number of customers grows so does the revenue.

17.7 Does FortisBC agree that there are fixed components to O&M costs that do not change based on the average number of customers?

Response:

FortisBC provides the following discussion to address a number of questions received on the appropriateness of its proposal to eliminate the 50 percent adjustment to the Growth Factor that is used in the Current PBR Plans for determining the level of O&M funding in the proposed MRPs.

In the current circumstances facing FEI and FBC, FortisBC's proposed index-based approach to O&M using a Base O&M per customer amount escalated by inflation and multiplied by the average number of customers each year is reasonable and appropriate for determining allowed O&M funding over the term of the MRPs. As discussed below, while there are fixed components to O&M in the short run, FortisBC's approach is reasonable.

Strong Linear Relationship between O&M and Average Number of Customers

FortisBC's supporting data and correlation analysis shows that, on aggregate, the relationship between the O&M and average number of customers is linear. As indicated in the response to BCUC IR 1.8.4 requesting the calculation of correlation coefficients for actual and formula O&M against the O&M formula cost driver (average number of customers), the results indicate a strong linear association between the cost driver and both actual and formula O&M. Given the nature of the O&M formula in the 2014-2019 PBR Plan, it is no surprise that formula-based O&M yields a strong linear relationship to customer numbers over the Current PBR Plan, but the linear relationship with customer numbers based on total actual O&M is also very strong.

Fixed vs. Variable Costs Cannot be Accurately Estimated

All of FortisBC's expenditures are related to and in support of providing safe and reliable service for our customers. All costs are variable in this sense, with total costs increasing as the number of customers served increase. This is consistent with the commonly expressed economic perspective that all costs are variable over the long run. The issue and debate then is how costs behave in the short term compared to their behaviour in the long run, how these short run and long run time periods are defined, and how this variability is appropriately reflected in the funding mechanisms for FortisBC's O&M expenditures.

In the short term, some of FortisBC's O&M costs are fixed (i.e., leases, rent), some are semi-variable (i.e., vehicle costs – insurance portion fixed while fuel costs variable based on vehicle usage) and some variable (i.e., customer billing and postage). FortisBC is unable, however, to provide an accurate estimate of what portion of its O&M costs are fixed, the portion of historical O&M costs for FEI and FBC that are reasonably impacted by the changes in the average number of customers, and specifically identify the O&M expenses which are impacted by changes in average customers.

Analysis of O&M under the Current PBR Plan Shows that O&M Costs Track Customer Growth

While FortisBC cannot accurately estimate all fixed and variable costs, the actual O&M cost results observed during the Current PBR Plan term (2014 to 2019) when analyzed against actual customers for the period support the use of FortisBC's proposed growth factor. This is evident from the regression analysis results included in the response to BCOAPO IR 1.23.1 and attached Excel spreadsheet. As shown in the analysis, the regression line slopes of $331.90 per customer added for FEI and $376.60 per customer added for FBC are similar in magnitude to the MRP formula O&M per customer of $250 per customer for FEI and $416 per customer for FBC.

When combined with the regression line y-axis intercepts, with results near or below zero for both utilities, this analysis shows that O&M cost growth has been tracking with the growth in average customers. Note that all of the years included in the regression analysis were within the Current PBR Plan term, meaning that the same incentive structure (50/50 sharing of O&M variances from formula-allowed O&M) affected management spending decisions throughout.

The results of this analysis should not be surprising as the economies of scale available to FortisBC should not be expected to change significantly given that the growth experienced over the Current PBR Plan term is small compared to the existing customer base. On this note, it is important to understand that FortisBC's economies of scale are already reflected in its proposed Base O&M per customer amount. Any growth experienced over the term of the proposed MRPs is unlikely to be great enough to materially improve the economies of scale available to FortisBC. Therefore, FortisBC's proposed Growth factor is reasonable and appropriate.

Proposed Growth Factor is Consistent with Cost of Service Allocation and Benchmarking Studies

Viewing customer count as the main driver of costs is also consistent with practices in cost of service allocation (COSA) studies and rate design. In the context of COSA studies, costs are classified as customer-related, capacity-related or volumetric-related. Volumetric-related costs typically comprise a very small percentage of overall costs, leaving customer-related and capacity-related costs responsible for nearly all of the utility cost of service[25]. Capacity-related costs, although treated differently than customer-related costs in a COSA study for allocating costs to the customer classes, are directly tied in aggregate to the number of customers served. Thus, both customer-related and capacity-related costs can be linked to customer counts when considering the overall costs of providing service.

The appropriateness of using the metric O&M per customer is also supported by the widely accepted use of O&M per customer as a common metric in benchmarking studies (e.g., the Concentric benchmarking study).

Variable Costs may Increase More than the Change in Average Number of Customers

The O&M per customer represents and includes a composite of a number of costs and a number of factors affecting the costs and provides a reasonable proxy for expected increases in O&M costs. Cost increases in some categories are more than the change in average number of customers (for instance there are cost increases that can happen without adding a single additional customer), some costs change on a 1:1 basis with increases in customers (e.g. billing and other customer care-related costs), and some costs may not increase in the short run with the change in average number of customers.

Recognizing that there will not be a perfect relationship between adding one customer and incurring a certain amount of O&M funding at the aggregate level, FortisBC's proposal incorporates the O&M per customer concept as a reasonable proxy.

For example, as discussed on page C-9 of the Application, in the case of adding an industrial customer which is typically much more costly than adding an additional residential customer, the Company is likely underfunded based on the proposed formulaic funding mechanism using the proxy O&M per customer. Significant industrial customer additions, likely not reflected in the O&M per customer Base used, will cause O&M funding pressures for the Companies.

Additionally, there may be situations where there may be increases in costs not anticipated that in the short run are not the direct result of an increase in customers. Examples of this include

[25] In FEI's COSA study in its 2016 Rate Design Application the costs were classified as 50.1% demand-related (i.e. capacity-related), 48.3% customer-related and 1.5% volume related. For FBC, excluding power supply costs, 100% of costs were classified as demand-related or customer-related in the most recent COSA filed as part of the 2017 Rate Design Application.

facilities rent/lease increases, changes in municipal regulations and related fees, higher vehicle operating costs including fuel charges and insurance, increase in corporate safety programs and activities, and changes in environmental regulation. FortisBC recognizes that the same examples can result in both increases or decreases to its O&M expenditures and are not the direct result of an increase in customers. Please refer to the responses to BCUC IRs 1.22.11 and 1.22.11.1 for a discussion of cost pressures, some of which may not be directly the result of an increase in the number of customers.

Expressing FortisBC's overall O&M costs as a function of the total number of customers provides an appropriate and reasonable proxy and basis to determine overall O&M funding for the MRP under a formulaic approach.

Conclusion

In summary, FortisBC recommends the proposed Index-Based formulaic approach based on average number of customers and the recommended inflation and growth factors as reasonable and appropriate for determining allowed O&M funding for the proposed MRPs. As also discussed in BCUC 1.17.6, the majority of index-based formulas used in other Canadian jurisdictions do not apply any adjustment to the growth factor (i.e. the formulas reflect 100 percent of the changes in their growth factor).

17.7.1 If yes, please identify these fixed components for FEI and FBC and explain whether and how FortisBC considered these fixed costs when proposing the growth factor of 1.0.

Response:

Please refer to the response to BCUC IR 1.17.7.

17.8 In consideration of the features of the MRPs in the Canadian jurisdictions described in Table B2-9 of the Application, please provide a detailed assessment and comparison of FortisBC's proposed MRP in terms of: (i) potential risk assumed by the utility; (ii) potential rewards which could flow to the utility; (iii) promotion of an efficiency focus; and (iv) achievement of targeted outcomes.

Response:

The potential risk and reward balance of an MRP directly impacts the efficiency focus objective of the MRP. Therefore, FortisBC addresses items (i), (ii) and (iii) in the question together.

The potential risks and rewards and the promotion of an efficiency focus depends on the strength of the incentives and the type of safeguard mechanisms in place. Ordinarily, the strength of MRP incentives is derived from the following MRP elements:

1. The amount of cost subject to the incentive framework:

   The more costs that are subject to incentives, the higher the risk and reward, and the higher the incentives for efficiency gains. Compared to the proposed MRPs and the MRPs in other Canadian jurisdictions, FEI's and FBC's Current PBR Plans had less costs subject to formulas (i.e., subject to incentives) as big cost items such as depreciation expenses were not subject to an incentive framework. Compared with the Current PBR Plans, the proposed MRPs include a larger set of cost items under an incentive framework as cost items such as depreciation expense are now subject to the sharing mechanism[26]. Further, although the capital formulas for the most part are replaced with capital cost forecasts, the capital expenditures are still subject to an incentive framework. In addition, all plans have some form of capital exclusion mechanism to deal with utilities' incremental capital needs not funded through the incentive framework. All plans also exclude non-controllable costs items from the incentive framework such as commodity related costs.

2. The length of the plan:

   The longer the plan's term, the higher the risk/reward potential. Most plans in Canada are between 4 to 6 years. The Hydro Quebec Distribution MRP has the shortest time period (with a four year plan; one year of which is cost of service for setting the base revenues). The plans' length in Alberta and Ontario are similar to FEI's and FBC's proposed five-year term, although, for some electric utilities in Ontario, one year out of five relates to cost of service rebasing.

3. Earning sharing mechanism:

   ESM reduces the risk of windfall surpluses or losses for both utilities and ratepayers; however, it also reduces the strength of the plan's incentives. The MRP plans in Alberta and some electric distributors in Ontario have no sharing mechanism, which translates to a higher risk/reward potential when compared with FEI's and FBC's proposed MRPs with symmetrical ESMs.

[26] Please see the FBC example provided in response to ICG IR 1.9.1 .

4. Other safeguard mechanisms:

   All plans have a set of safeguard mechanisms that reduce the potential risks to both utilities and/or ratepayers. These include items such as off-ramp provisions, service quality indicators and exogenous factor treatment. There is no significant difference between various plans on these issues and therefore one can assume the same level of risk/reward potential for all jurisdictions. FEI's and FBC's Current PBR Plans have an additional capital dead band safeguard mechanism, which is now removed from the proposed MRPs.

5. Efficiency carry-over mechanism (ECM):

   ECMs can also impact the strength of incentives, particularly during the last few years of the plans. FEI's and FBC's proposed MRPs include a limited ECM similar to the one used by Alberta utilities. Further, pursuant to the OEB's consolidation handbook, consolidating utilities can apply for deferred rebasing which means that they can keep any savings from previous years for a number of additional years. As such, FortisBC assesses that its proposed ECM provides the same level of incentive available in other jurisdictions. Hydro Quebec, however, does not have any ECM, although due to the shorter-term period, the ECM may be less important.

Regarding item (iv), the achievement of targeted outcomes are increasingly popular in the U.S. The Canadian MRP plans reviewed in Appendix C4-2 of the Application did not have a similar targeted incentive framework. The OEB has initiated a consultation process for review of Utility Remuneration schemes for promoting innovation (EB-2018-0287) in coordination with another policy initiative titled Responding to the Distributed Energy Resources (EB-2018-0288), but no decision is issued yet.

Based on the above factors, the potential risk and reward balance and the associated incentives of FortisBC's proposed MRPs is similar to or slightly lower than that of the MRPs in the Canadian jurisdictions described in Table B2-9 of the Application. The type of costs subject to the incentives as well as the term, safeguard and ECM mechanism in the proposed MRPs are similar compared to the other MRPs. FortisBC's MRPs include Targeted Incentives that increase the potential rewards to the utility, balanced by the benefits to customers and the public interest of achieving the targets. Compared to other MRPs, the potential risks/rewards of FortisBC's proposed MRPs are also tempered by the inclusion of a symmetrical 50/50 earning sharing mechanism.

17.9 Please confirm, or explain otherwise, that none of the Canadian jurisdictions included in Table B2-9 of the Application have included targeted incentives in their MRPs.

Response:

Confirmed. While none of the Canadian plans reviewed in Table B2-9 include similar targeted incentives, targeted incentives are growing in popularity in the U.S. (particularly for electric utilities). However as mentioned in response to BCUC IR 1.17.8, The OEB has initiated a consultation process for review of Utility Remuneration schemes for promoting innovation (EB-2018-0287) in coordination with another policy initiative titled Responding to the Distributed Energy Resources (EB-2018-0288), but no decision is issued yet.

17.9.1 As part of the above response, please explain the likely reasons why targeted incentives were not included in other Canadian jurisdictions' MRPs.

Response:

FortisBC cannot speculate why Canadian utilities studied in this Application have not applied for similar targeted incentives. However, the absence of targeted incentives in other Canadian jurisdictions should not be viewed as undermining the merits of FortisBC's proposal. First, other Canadian utilities may very well propose such mechanisms in their future applications. Second, BC is at the forefront of the transition to a lower carbon economy and therefore, it is not a surprise that a company like FEI, who has been an industry leader in developing NGT and RNG programs, is also the first Canadian utility to request additional regulatory support in the form of targeted incentives to address rapid industry transition. Third, the BCUC has a long history of providing leadership by approving innovative regulatory mechanisms. This is evidenced by the fact that BCUC was the first regulator to approve PBR-type plans in Canada, setting the trend for other Canadian jurisdictions.

17.10 Please explain if there are any Canadian jurisdictional examples where there is no productivity factor but there is the inclusion of one or more targeted incentives. If yes, please identify the jurisdiction(s) and compare the jurisdiction(s) to FEI and FBC.

Response:

Please refer to the response to BCUC IR 1.17.9. Further, please refer to the responses to BCUC IRs 1.13.2 and 1.13.3 for a detailed discussion of FortisBC's productivity factor proposal.

17.11 Please explain the differences in FEI and FBC's operating environments compared to the other Canadian jurisdictions in Table B2-9 of the Application which would support the inclusion of targeted incentives.

Response:

FortisBC has mainly focussed its research efforts on jurisdictions that have included targeted incentives. However, it is worth noting that BC's operating environment is unique in Canada. BC is a leader in many respects and is among the first jurisdictions in Canada to have implemented:

- Performance-based regulatory frameworks (as noted in the response to BCUC IR 1.17.9.1);
- A carbon tax;
- A performance-based energy step code; and
- A clean fuel standard.

As indicated in Section B1 of the Application, the federal government continues to work towards implementing the climate initiatives noted above that are already in place in BC. The advancement of climate policy in BC relative to other Canadian jurisdictions stems from its already relatively clean energy sector. An abundance of clean electricity from hydroelectric sources means provincial emissions reductions have focussed on more difficult transformations. For example, the City of Vancouver has announced its intention to transition to zero emissions heating and hot water for all buildings by 2025.

In this regard, FortisBC is challenged differently than other utilities across Canada. In response, FortisBC has created an approach tailored to its environment, which reflects its unique operating context. As noted in the response to BCUC IR 1.17.9.1, the absence of similar targeted incentives in other Canadian jurisdictions should not be viewed as evidence to undermine the merits of FortisBC's proposal. Moreover, FortisBC's research on similar incentive frameworks is a relevant basis for comparison and is addressed in Section B2 of the Application.

On page 2 of Appendix C4-2, FortisBC states that the Alberta Utilities Commission's (AUC) scope of the second generation PBR proceeding was mainly limited to three items: (i) rebasing and going-in rates; (ii) X-factor value update; and (iii) capital tracker mechanism.

17.12 Please discuss the pros and cons of the AUC approach to the second generation PBR proceeding, including the pros and cons of focusing on making adjustments to only a few key components of the first generation PBR plan.

Response:

The biggest advantage of the AUC's approach to limit the scope of its PBR proceeding is reduced regulatory burden and costs. The biggest disadvantage to this approach relates to stakeholders' inability to assess the integrated nature of PBR elements and to have a thorough assessment of the incentives embedded within the plan. MRPs are ordinarily in place for a number of years and, in FortisBC's view, it is important that utilities, interveners and the regulator have the chance to review the entire incentive framework that will affect the companies' operations for the near future rather than be limited in their ability to provide comments or suggestions.

AUC's decision to limit the scope of its PBR proceeding was influenced by the timing of its proceeding. The issue list was finalized in August of 2015, less than three years since the start of the plan. The Companies pointed out that it may not be meaningful at that time to assess the success of the existing PBR plans in order to explore options for the next generation of PBR plans. Customer groups on the other hand, advocated that a full review is needed and suggested that significant changes may be required. The AUC agreed with the utilities' view:[27]

> The Commission agrees with the companies' view that the limited experience to date under the PBR plans makes an evaluation of the success of the plans and an assessment of any changes to the fundamentals of the plans difficult. Parties have had less than three full years of experience under the current PBR framework, with only the first year of the plans nearing completion of a full capital tracker true-up cycle with the approval of compliance filings by some of the companies …
>
> In these circumstances, a complete review of the success of the existing PBR plans based on achieving all of the objectives for the plans as set out in Decision

[27] AUC's letter, Aug 21, 2015.

2012-237 or a reconsideration of all elements of the plans, would neither be an efficient use of time and resources, nor is it likely to result in a meaningful, well-considered exercise at this time. Accordingly, the Commission will not undertake an assessment of the success of all of the various provisions of the existing PBR plans, nor will it consider a restructuring of a majority of the components of the plans at this time.

FortisBC did not have the same timing issue. Moreover, the Companies' Application includes a thorough assessment of the Current PBR Plans' strength and weaknesses and provides proposals to build on their success and mitigate the assessed weaknesses which was requested by both intervener groups and BCUC staff. Further, FortisBC believes that intervener groups would prefer the proposed approach to the limited scope approach used by AUC.

Despite the more thorough approach adopted by FortisBC, the magnitude and significance of changes approved/proposed in the two jurisdictions are comparable. This is because the majority of the items that were excluded from the AUC's scope are also the ones that are proposed to remain more or less unchanged in FortisBC's Application (these include the O&M formulas, FEI's Growth capital formula, the inflation factor, the off-ramp provisions, the majority of service quality indicators, the annual review process, symmetrical earnings sharing mechanism and exogenous factor treatment). The AUC made significant changes to its capital tracker mechanism, while FortisBC's proposed capital exclusion approach remains unchanged.

FortisBC acknowledges that the Innovation Fund and the Targeted Incentives are two proposals that are new to the BCUC and other stakeholders. As explained in response to a number of information requests, these initiatives seek to address the challenges and opportunities associated with changing operating environment that is specific to BC. Some jurisdictions may not face the same pace of industry transition and may defer these issues to the future; some such as Ontario may pursue these issues in separate proceedings (please refer to the response to BCUC IR 1.17.8), and some like FortisBC may include them as part of their ratemaking plans.

17.12.1 As part of the above response, please discuss whether such an approach was considered by FortisBC. If not, why not? If yes, why was this approach not considered appropriate?

Response:

Please refer to the response to BCUC IR 1.17.12.

18.0 Reference: REVIEW OF OTHER JURISDICTIONS

Exhibit B-1, Section B2.6, pp. B-73 – B-77; Exhibit B-1-1, Appendix C4-2, pp. 35–42

Performance Incentive Frameworks in the US

On pages 35–42 of Appendix C4-2, FortisBC describes New York's Reforming the Energy Vision (REV) strategy plan, stating that the "REV initiative aims to reorient both the electric industry and the regulatory paradigm toward a consumer-centered approach…"

18.1 Please clarify if the REV is applicable only to electric utilities or to both electric and natural gas utilities.

Response:

REV stands for "Reforming the Energy Vision" which includes both electricity and natural gas. The REV-related programs and incentives were initially focused on electric distribution sectors. However, recently natural gas distributors have also started to catch up to their electric counterparts and have filed applications or are developing projects that are sometimes referred to as "Gas REV".

The National Grid website, for instance, has a Gas REV section that defines the company's plan under the REV regime[28]:

> National Grid is the first utility in New York State to propose a set of natural gas initiatives for the "Reforming the Energy Vision" initiative.
>
> We believe that clean, abundant natural gas will be an important part of the low-carbon energy mix of the future. Natural gas can deliver large-scale reductions in carbon emissions and provide a bridge to long-term clean energy solutions. As one of the leading gas utilities in the United States, National Grid is supporting natural gas innovations on both the company and the customer sides of the meter.
>
> We have submitted a number of proposals to improve our energy infrastructure. Among these are strategic goals for 21st-century Northeastern gas distribution services. We will begin by implementing collaborative demonstration projects in the following areas:
>
> - Resilient, safer, and smarter networks (AMI, data analytics, and instrumentation)

[28] https://www.nationalgridus.com/new-energy-solutions/Community-Projects/New-York/Gas-Rev.

- Residential methane and flood detectors (with remote and automatic shutoff)
- Gas technology for electric constraints (microCHP and other non-heat use of gas)
- Customer options for gas constraints (commercial gas demand response)
- Green gas tariff program for customers

Other utilities such as New York State Electric & Gas Corporation (NYSEG) are also looking into REV initiatives, such as non-pipeline alternatives (similar to non-wire alternatives) seeking innovative solutions to address natural gas reliability, demand, and/or supply in its service territory[29]. Another example is Con Edison's natural gas demand response pilot program[30].

18.2 Please compare and contrast FEI and FBC's operating and regulatory environments in BC to New York.

Response:

The state of New York is served by six large investor owned utilities (Central Hudson, ConEdison, National Grid, NYSEG, RG&E and Orange and Rockland), one large municipal utility (LIPA), and many smaller utilities. Consolidated Edison, or ConEd, is geographically the smallest of the investor owned utilities in New York, but it serves the largest number of customers (ConEd provides service to the city of New York).

New York's and FortisBC's regulatory environments are comparable, as indicated in the table below.

Item	FortisBC	Typical New York Utility
Test year	Use of forecast test years	Use of fully-forecasted test year
Rate making approach	Periodic indexed or forecast 5 year MRPs for revenue requirement determination with earning sharing mechanisms	3 year forecast MRPs with earnings sharing

[29] https://nyrevconnect.com/non-pipeline-alternative-rfi-nyseg/
[30] https://dailyenergyinsider.com/news/15828-con-edison-launches-demand-response-program-for-natural-gas-customers/

Item	FortisBC	Typical New York Utility
Demand risk	The Companies' are protected from demand variation risk through flow-through mechanism.	Full revenue decoupling offsets the effect on earnings of variations in sales for any reason
Incremental Capital	Treatment of major capital expenditures not funded through the MRP and is outside the incentive framework	Utilities may implement riders to recover carrying costs on incremental expenditures associated with projects such as replacement of leak prone pipe
Deferral accounts	Use of deferral accounting for items such as taxes, pension and OPEB, debt expense and other non-controllable costs. History of using deferral accounts for rate smoothing purposes	Deferral accounting for items such as pension and OPEB, property taxes, debt costs, major storm cost reserves, etc. New York has a history of using deferral accounts for rate smoothing purposes
Stranded assets Risk	Utilities have been historically able to recover the prudently incurred costs of their undepreciated costs	Utilities have been historically able to recover the prudently incurred costs of their undepreciated costs
Commodity price risk	Utilities are protected from commodity price risks through adjustment clauses.	Distributors are fully divested and protected from commodity risk. Adjustment clauses allow the utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier.

One important difference between New York and BC electric utilities relates to generation assets. While FBC and BC Hydro are vertically integrated utilities with sizable generation assets in the rate base, virtually all of the New York utilities' generation assets were divested as part of the electricity industry restructuring. The incumbent power distributors, however, have retained the provider-of-last-resort obligation, and are procuring the power to meet this obligation through bilateral wholesale contracts with competitive suppliers. Most of the utilities physically purchase the majority of their required energy on the New York Independent System Operator (NYISO) Day-ahead market. NYISO is a non-profit organization responsible for managing New York's electric grid and its competitive wholesale electric marketplace.

On the other hand, similar to FEI, New York's gas distribution companies do not have an interest in the gas commodity business and sell gas with no mark-up to those customers who choose to buy gas from the utilities.

Another important difference between New York and BC relates to the role and function of New York State Energy Research and Development Authority (NYSERDA). NYSERDA is a public-benefit corporation with the mission to advance innovative energy solutions in ways that

improve New York State's economy and environment. Some of NYSERDA main objectives include increasing the state's energy efficiency and conservation, growing renewable and diverse energy supplies, and protecting the environment. Since 1996, NYSERDA's budget is funded by ratepayers through the System Benefit Charge (SBC) program. The SBC is collected by investor-owned utilities from gas and electric customers in the State, and funds the majority of NYSERDA's programs. In contrast, such as an organization does not exist in BC and most of the energy efficiency and conservation efforts as well as other innovative solutions to decarbonize BC's economy are managed by the utilities.

18.3 How many electric utilities operate in New York?

Response:

Please refer to the response to BCUC IR 1.18.2.

18.4 How does FBC's number of customers and electric volumes compare to the electric utilities in New York?

Response:

The table below provides a summary of the number of customers of and energy delivered by New York electric distributors (as shown in their websites). As can be seen in the table, FBC has a lower customer count and lower electricity load compared to all investor utilities in New York.

Company	Number of Electric customers (Rounded)	Electricity delivered
Central Hudson	300,000	4,891 GWh
ConEdison	3,500,000	56,837 GWh
Orange and Rockland Electric	300,000	5,617 GWh
Rochester G&E	380,000	7,016 GWh

Company	Number of Electric customers (Rounded)	Electricity delivered
NYSEG	895,000	15,374 GWh
Niagara Mohawk (NGrid)	Not readily available[31]	
FBC[32]	137,000	3,250 GWh

18.5 Please compare and contrast FEI and FBC's proposed MRPs, including the proposed targeted incentives, to the rate-making model(s) utilized in New York.

Response:

As explained in Section 6.1 of Appendix C4-2, New York Public Service Commission (NYPSC) has a long history of adopting multi-faceted, forecast, multi-year rate plans. Most of the major utilities are operating under plans that include asymmetrical earnings sharing provisions, with earnings in excess of an established threshold to be shared by shareholders and ratepayers. Each of the electric and gas utilities in New York operate under a full revenue decoupling mechanism (RDM). The RDMs provide for the companies to implement a rate surcharge or credit associated with a revenue shortfall or over-collection related to a predetermined revenue target. As a result, the RDMs offset the potential effect on earnings of any variation in sales, whether the variation is caused by energy efficiency, weather, or the economy. New York MRPs include deferral accounting for cost items such as net plant, pension expense, and labour costs.

In comparison, FEI's and FBC's proposed MRPs are for a five year period, include a symmetrical earnings sharing mechanism and apply an index approach to O&M as well as FEI's Growth capital cost (as opposed to forecast). Similar to New York utilities, FEI's and FBC's costs are decoupled from their revenues. Further, similar to New York, FEI's and FBC's proposed plans include various regulatory treatments of certain non-controllable and/or recurring costs. One difference is in net plant; as explained on page 36 of Appendix C4-2, the so-called clawback mechanism adopted by NYPSC provides that earnings from capital programs that fall below the approved levels must be returned back to customers (the exception

[31] National Grid owns natural gas and electric utilities in New York, Massachusetts and Rhode Island. The data on its website is provided on the aggregate level only. Niagara Mohawk, the biggest grid-owned electric utility in New York has more than 1.5 million customers.

[32] Based on 2018 numbers.

to this are those capital projects that are replaced or deferred by REV related projects). No such mechanism exists in FortisBC's proposed MRPs.

In terms of targeted incentives, each New York utility has to propose individual Earning Adjustment Mechanisms (EAMs) that are tailored to their specific needs and circumstances. The EAMs provided in Section 6.1.2.4 of the Appendix C4-2 are the major categories of EAMs identified by NYPSC and not the exact EAMs approved for each utility. The major categories identified by NYPSC are as follows: system efficiency, energy efficiency, interconnection, GHG reduction, customer engagement and affordability.

FortisBC's proposed targeted incentives generally align with the GHG reductions, customer engagement and affordability EAMs identified above.

On pages B-73 and B-74 of the Application, FortisBC describes the three major types of incentives included in New York and California: (i) reforms to the traditional cost of service framework; (ii) non-wire alternative programs; and (iii) outcome-based targeted positive incentives.

18.6 For each of FEI and FBC, please explain in detail how FortisBC's proposed incentives compare to the three types of incentives listed in the above preamble.

Response:

Reforms to the traditional cost of service framework

As explained in Section 6.1.2.1 of the Appendix C4-2, the approved reforms to traditional cost of service framework in New York relates to the so-called, claw-back mechanism reform. Under the new approach, utilities can retain the earnings related capital savings until the next rate case if they can show that the saving relates to replacing or deferring capital projects with distributed energy resources such as efficiency and conservation efficiencies and non-wire/non-pipe solutions.

This is similar to the traditional incentives discussed on page C-156 of the Application. Under the Companies' proposed incentive framework, any variance between formula/forecast and actual capital spending is subject to the 50:50 symmetrical earnings sharing mechanism.

Non-wire/Non-pipe Alternative solutions

As stated in Section 6.1.2.3 of Appendix C4-2, these alternative solutions ordinarily relate to the type of projects that would replace, reduce and/or defer traditional capital infrastructure investments that otherwise would be needed to accommodate the growth in expected locational peak demand. The amount of incentives for these projects is decided on a case-by-case basis.

So far, FortisBC has not asked for any specific incentive framework for non-wire/non-pipe solutions. However, FortisBC may use these type of initiatives to defer/replace traditional investments for peak demand management. For instance, prior to the implementation of Whistler expansion project, FEI was able to use a mobile LNG peak shaving system to defer the needed traditional capital investments for a number of years. Any savings from deferring these types of capital investments is subject to the traditional incentives discussed above.

Outcome-based Positive Targeted Incentives

The proposed Targeted Incentives are similar to outcome-based targeted positive incentives also known as Earnings Adjustment Mechanisms (EAMs) that were discussed in Section 6.1.2.4 of Appendix C4-2 of the Application.

FortisBC followed the same general guidelines that were set by New York Public Service Commission (NYPSC) for developing EAMs:

- The EAMs should ordinarily be outcome-based not program-based: FortisBC's proposed targeted incentives are all outcome-based. FortisBC is not asking for approval of specific programs to achieve the targets, but rather is asking for approval of the targets and incentives for achieving those targets. FortisBC will be challenged to find innovative solutions to achieve the proposed targets.
- EAM incentives shall be designed in a manner that would avoid counterfactuals: FortisBC's proposed targets and incentives are fixed and pre-determined and are not subject to counterfactuals.
- EAM incentives shall ordinarily be positive only: FortisBC's proposed targets are positive only in nature. This is because the proposed Targeted Incentives are established for activities with positive only values; therefore, the more they are rewarded, the more customers benefit.
- The maximum amount of earnings for the initial EAM incentives should not be more than 100 basis points: The maximum amount of incentives for each of FEI and FBC is less than the maximum threshold set in NYPSC's guidelines.
- Each proposed EAM should be in place for a number of years: FortisBC's Targeted Incentives are in place for the entire five-year MRP term.

As explained in the response to BCUC IR 1.18.5, each New York utility proposed EAMs that are tailored to its specific needs and circumstances. The EAMs provided in Section 6.1.2.4 of Appendix C4-2, are major categories of EAMs identified by NYPSC. A review of EAM categories identified by NYPSC indicates that FortisBC's proposed Targeted Incentives are aligned with the EAM categories identified by NYSPC:

Targeted incentives proposed	Equivalent EAM category identified by NYPSC
Growth in Renewable Gas	GHG reduction: The proposed targeted incentive will supply more customers with zero emission gas and will help to expedite and promote government policy to decarbonize the BC economy.
Growth in NGT	GHG reduction – Affordability – System efficiency: The proposed incentives will reduce BC's and global GHG emissions by replacing higher emitting fossil fuel in transportation and marine industries with lower emissions lower cost natural gas which will significantly reduce customer fuel costs. Further, NGT customers are ordinarily high load factor customers and therefore adding more NGT customers can improve system efficiency.
GHG Emissions Reduction (FEI's customers)	GHG reduction – Affordability: The proposed incentives will help to reduce customers' GHG emissions by converting them from higher carbon energy sources to natural gas while lowering customers' annual energy bills.
GHG Emissions Reduction (FEI)	GHG reduction: The proposed incentives will help FEI to expedite the reduction of its own GHG emissions in support of government policy to decarbonize BC's economy.
Customer Engagement	Customer engagement: Similar to customer engagement EAMs identified by NYPSC, the proposed incentives are linked to the successful adoption of digital service channels by FBC and FEI customers.
Growth in EV Transportation	GHG reduction – Customer engagement: The proposed incentives will help to reduce GHG emissions and reduce "range anxiety" associated with electric vehicles by increasing the availability of charging stations. This will improve customer adoption and thus their engagement with government policy to phase-out gas-powered vehicles in the province.
Power Supply Incentive (PSI)	PSI related incentives are not new and are mainly used to improve the efficiency of FBC's power supply practices.

18.6.1 If FortisBC's proposed incentives do not relate to one or more of the three types listed in the above preamble, please explain why FortisBC has not proposed incentives similar to those types of incentives.

Response:

Please refer to the response to BCUC IR 1.18.6.

18.7 Please explain in detail, with supporting references, the key drivers behind New York's utility incentives and how these drivers compare to each of FBC and FEI's drivers.

Response:

The key driver of the alternative incentive frameworks developed in various North American jurisdictions can be summarized as industry transition fueled by rapid technological advancements and government energy and climate policies.

The New York Public Service Commission (NYPSC) identified a series of trends that derive the need for the regulatory reforms under the REV initiative. These include, but are not limited to the following:

1) Regulatory models that were built based on 20th century technology and assumptions:

   The order states that the traditional revenue model has served reasonably well for the last century. However, the traditional revenue model was developed under assumptions than no longer hold with today's technological advances and demand patterns. These assumptions include:

   a. Customer demand driving capital investments, which was largely beyond the influence of utilities.

   b. Economies of scale almost invariably favored large utility-scale investments.

   c. The need to instantaneously balance supply and demand, coupled with the obligation of reliable universal service, inevitably required large expenditures for redundancies throughout the system.

d. End-use customers were the only substantial source from which system costs can be recovered.

The order concludes that these assumptions led to a revenue model that encourages investment in a utility system that is based on central station generation, unidirectional flows (both of power and transactions) and minimal elasticity of demand.

New technological advancements such as smart meters, distributed energy resources (DERs) and electricity storage technologies question the relevance of these assumptions. Further, the traditional revenue model is not capable to sufficiently address the challenges of aging infrastructure, higher peak demand and flat rates which is leading to higher rates for customers. New forms of incentives can help to amend the shortcomings of traditional rate-base incentives.

2) Clean energy and environmental responsibility:

The order states that climate change poses several different types of challenges to the energy industry. These challenges include, but are not limited to: the need to reduce carbon emissions; the need to address the reliability and resilience concerns driven by severe weather that will increase infrastructure costs and may also impel more customers to seek self-generation solutions; and the increasingly severe weather trends that will eventually force a wider range of load forecast planning scenarios, which would exacerbate the inefficiency of planning to meet uncontrolled system peaks.

The responsibility to address these challenges is shared by the governments, utilities and their customers. Targeted incentives can align the interests of all stakeholders to achieve a public good. The NYPSC made the following conclusion:

> Utilities, and this Commission, could respond to these challenges by clinging to the traditional business model for as long as possible, relying on protective tariffs, regulatory delay, and other defenses against innovation. A variation on this approach would be to assume a reactive posture, addressing issues only when they have grown into critical or highly visible problems. Alternatively, we can identify and build regulatory, utility and market models that create new value for consumers and support market entrants and this new form of intermodal competition – in other words, embrace the changes that are shaking the traditional system and turn them to New York's economic and environmental advantage.
>
> We decisively take the latter approach. For a century, policy goals were adequately served by regulatory methods that encouraged a static and unidirectional model of utility service. In the modern economy, the goals of

reliable, affordable and clean electric service will not change; but the methods of achieving them must.

18.8 Please explain in detail, with supporting references, the key drivers behind California's utility incentives and how these drivers compare to each of FBC and FEI's drivers.

Response:

The California case had a much more limited scope than New York's REV initiative.

The California decision is specifically related to the deployment of distributed energy resources on the system to displace or defer the need for capital expenditures on distribution infrastructure. The focus in California is to level the playing field between the traditional utility solutions (usually more capital intensive) and non-traditional solutions (usually more O&M intensive).

C. PROPOSED RATE PLAN

19.0 Reference: INTRODUCTION AND GUIDING PRINCIPLES

Exhibit B-1, pp. B-60 – B-63, C-1 – C-2; Appendix C4-2; Exhibit B-2 (Workshop Material), Appendix B; FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for the years 2014 through 2018 Decision and Order G-138-14 (FEI PBR Decision), pp. 15–16

Comparison of Proposed MRPs and Current PBR Plans

FortisBC states on page C-1 of the Application that the five "Rate Plan Principles" for the proposed MRPs "are consistent with the common themes in the principles used in most jurisdictions, although they are articulated in many different ways" and it states in footnote 102 on page C-1 that these principles are expressed by the Alberta Utilities Commission (AUC) in Bulletin 2010-20 dated July 15, 2010.

19.1 Please explain how FortisBC's five principles for the proposed MRPs compare to the principles of the AUC's most recent MRPs referenced in Table B2-9 and Appendix C4-2 of the Application.

Response:

The AUC's PBR principles for its second generation PBR are the same principles adopted in its first generation PBR. Bulletin 2015-10, indicating AUC's intention to proceed with a next generation PBR regulatory regime for the distribution utilities, stated the following:

> The Commission proposes to continue with PBR regulation of electric and gas distribution utilities in accordance with the five PBR principles that the Commission adopted in the first generation PBR plans.

The AUC's approved PBR principles in AUC's first generation PBR and their comparison with FortisBC principles are provided in the Table below:

AUC's Principles	Comment and Comparison with FortisBC's Proposed Principles
Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality	This is comparable to FortisBC's proposed 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 AUC recognizes that even a comprehensive PBR Plan cannot match the efficiency of a competitive market. Having recognized that goal, the principle offers a reasonable basis for assessment of the plan elements, but care must be taken to strike a balance with other plan objectives such as Principle 2.
Principle 2: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.	This is identical to FortisBC's proposed Principle 2
Principle 3: A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.	This is identical to FortisBC's proposed Principle 5.
Principle 4: A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.	This is identical to FortisBC's proposed Principle 3.
Principle 5: Customers and the regulated companies should share the benefits of a PBR plan.	This is similar to FortisBC's proposed Principle 1: "MRP should, to the greatest extent possible, align the interests of customers and the utility; customer and the utility should share the benefits of the MRP"

19.2 Please compare FortisBC's five principles for the proposed MRPs to the other jurisdictions listed in Table B2-9 and Appendix C4-2 of the Application with specific reference to each jurisdiction's principles/themes.

Response:

FortisBC's review of the decisions of regulators in other jurisdictions indicates that the approved principles in first generation PBR plans usually remain unchanged in subsequent generations, and that decisions for next generation plans may not discuss the principles or may simply refer to the previous decision, as in the case of AUC's second generation PBR decision. The

comparison of FortisBC's proposed principles with the AUC's principles is discussed in response to BCUC IR 1.19.1. The comparison with other jurisdictions is provided below.

Quebec

The objectives listed in the second paragraph of the Article 48.1 of "La loi sur la Régie de l'énergie" (or Act respecting the Régie de l'énergie) are as follows:

Regie's objectives[33]	Comment and comparison with FortisBC's proposed principles
The continuous improvement of performance and quality of service	This is in line with FortisBC's proposed 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.
Achieve cost savings that are shared between customer and utilities	This is similar to FortisBC's proposed Principle 1: MRP should, to the greatest extent possible, align the interests of customers and the utility; customer and the utility should share the benefits of the MRP
Streamline the regulatory process for rate-setting purposes	This objective is similar to FortisBC's proposed Principle 5: The MRP should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Ontario

The OEB's Handbook to Utility Rate Applications[34] (the Handbook) outlines the key principles and expectations the the OEB will apply when reviewing rate applications. The Handbook has been developed based on the OEB's policies and the experience gained through the processing of rate applications since the release of the Renewed Regulatory Framework for Electricity (RRFE). Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation). The OEB set out its goals for the RRFE as follows:

> The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an

[33] The original text as provided in Article 48.1 is as follows: 1. l'amélioration continue de la performance et de la qualité du service; 2. la réduction des coûts, profitable à la fois aux consommateurs et, selon le cas, au Distributeur ou au Transporteur; 3. l'allégement du processus par lequel sont fixés ou modifiés les tarifs du Transporteur et les tarifs du Distributeur applicables à un consommateur ou à une catégorie de consommateurs.

[34] https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf.

appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.

The OEB states that these principles are guided by two of the objectives listed in section 1(1) of the OEB Act:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

FortisBC's proposed principles are generally aligned with the objectives and principles outlined in the OEB's Handbook and OEB Act.

On pages C-1 and C-2 of the Application, FortisBC provides the following table which outlines the five "Rate Plan Principles" for the proposed MRPs:

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.

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.

On pages B-60 – B-62 of the Application, FortisBC describes the December 2018 workshop which it hosted to review the merits of multi-year rate plans compared to cost of service regulation.

On page B-62 of the Application, FortisBC states the following:

> 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.

19.3 Please explain how FortisBC has specifically addressed the above concerns of the interveners in this Application.

Response:

FortisBC notes that not all interveners are necessarily opposed to a PBR plan and some interveners have commented on positive aspects of the Current PBR Plans.

The BCMEU acknowledged as part of the FBC Annual Review for 2019 Delivery Rates (page B-63 of the Application) that there have been positive O&M savings for the benefit of ratepayers, but expressed concern about capital expenditures.

MoveUP commented as part of the FEI Annual Review for 2019 Delivery Rates (page B-63 of the MRP Application):

> FEI has demonstrated in this Annual Review that is able to check virtually all of the boxes currently presented by the 2014-2019 PBR.

The BCOAPO suggests consideration for a modified and much more limited PBR Plan (page B-64 of the Application):

> 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”.

Regarding the concerns expressed by the interveners for alternative types of ratemaking arrangements than another PBR, FortisBC believes it has undertaken sufficient discussion with stakeholders to solicit feedback to shape its proposed MRPs. While there may be some interveners that believe a cost of service type approach is the only appropriate type of ratemaking approach for the next term, FortisBC respectfully does not agree. FortisBC instead believes that its proposed MRPs, which incorporate features consistent with a cost of service approach (i.e., five year capital forecast approach) and address emerging challenges in its operating environment, are the appropriate approach at this time. FortisBC’s proposed combination of performance-based and cost of service elements strikes the appropriate balance between maintaining an efficiency focus, allowing for continued investment in a safe and reliable system, and achieving climate related goals that allow the continued viability of the Utilities for the future.

It is in the best interest of customers, the Utilities and the public for the Utilities to pursue projects which address strategic and emerging issues, serve customer needs, and maintain the long-term health of the Utilities. In this regard, FortisBC believes its interests are aligned with its customers.

Please also refer to Section C9.3 of the Application (The Plan Addresses Intervener Concerns) for further discussion of how the changes FortisBC made address concerns expressed by interveners.

19.4 Please explain, with reference to specific intervener feedback, how a five-year cost of service based approach to the majority of FBC's regular capital and to FEI's sustainment/other capital addresses the concerns of interveners.

Response:

In Section C9.3 of the Application, FortisBC highlighted that 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 proposal was at least partly in response to intervener comments that the existing formulaic capital mechanism is not working and that managing capital spending within the allowed funding was a challenge for FortisBC. The five-year cost of service forecast for capital approach also addresses some interveners' desire for further transparency into FortisBC costs that would be provided through a review of the Companies' capital costs in a cost of service proceeding.

This desire to consider a multi-year cost of service approach to determining capital funding was expressed by the BCOAPO as part of the FEI Annual Review for 2019 Delivery Rates process. In its comments provided, the BCOAPO noted (page B-64 of the MRP Application):

> 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".

In addition, many of the interveners in the FEI and FBC Annual Review for 2019 Delivery Rates expressed specific concern about the current formulaic approach to capital funding. MoveUP commented that: (pages B-62 and B-63 of the MRP Application)

> 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 flies its proposal for second consecutive PBR cycle in 2019.

The BCMEU acknowledged that there have been positive O&M savings for the benefit of ratepayers but expressed concern about capital expenditures: (page B-63 of the MRP Application)

> The BCMEU remains concerned, as do other participants in the proceeding, about the significant source in formula capital expenditures, particularly in the later year 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.

The CEC commented at paragraph 78 of its Final Argument in FEI's Annual Review for 2018 Delivery Rates:[35]

> The CEC submits that the consistent over-spending relative to formula for capital is evidence that the formula has over-simplified a complex cost structure and does not serve its purpose well.

FortisBC has interpreted the above comments to be consistent with its proposed five year cost of service based approach for the majority of capital funding required.

19.5 Please explain, with reference to specific intervener feedback, how FortisBC's proposed changes to the O&M formulas for FEI and FBC address the concerns of interveners.

Response:

In Section C9.3 of the Application, FortisBC explained that the new Index Based (i.e., indexed to inflation only) approach to determine O&M funding available during the term of the Proposed MRPs will provide FortisBC with a stable level of O&M funding, helping to de-emphasize the focus on achieving a significant accumulating productivity improvement factor for each year. This was responsive to those concerns expressed by interveners (and supported by FortisBC) about the potential need for the utility to shift its focus from traditional "cost-cutting".

MoveUP in the FEI Annual Review for 2019 Delivery Rates commented that:

> … it is likely that there are less realizable efficiencies for FEI to pursue in its next ratemaking agreement.

[35] Online: https://www.bcuc.com/Documents/Arguments/2017/DOC_50296_11-09-2017_CEC-Final-Argument.pdf.

The BCOAPO referenced the concept of "indexes only O&M" in the FEI Annual Review for 2019 Delivery Rates: (page B-64 of the MRP Application)

> 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".

FortisBC has interpreted the above comments to be consistent with its proposed Index-based approach for O&M funding.

19.6 Considering Principle 1, and customers' general desire for utilities to reduce costs (which in turn could lead to lower rate pressures), please discuss how elimination of the X-Factor in the proposed MRPs aligns with the aforementioned customer interest.

Response:

The elimination of the X-Factor (or implied X-Factor of zero) does not eliminate the focus for FortisBC to achieve productivity for the benefit of customers and the Companies. As noted in the response to BCUC IR 1.6.3, it is not the X-Factor itself that gives rise to savings, but rather the type of costs subject to the incentive framework, the length of the plan, the decoupling of cost and revenues, and the type of the earnings sharing mechanism applied (if any). However, productivity expectations in the MRPs will be less about rebasing and cutting costs, and will instead encourage FortisBC to focus more on the efficient allocation of existing resources within the business by "doing more with what we have". Additionally, FortisBC will continue to pursue productivity improvements under the proposed MRPs with a focus also on addressing emerging challenges in its operating environment. Achievement of the two priorities are in customers' interests.

19.7 Please confirm, or explain otherwise, that the guiding principles for the Current PBR Plans and for the proposed MRPs are the same. If not confirmed, please identify where they are different.

Response:

Except for changing the references from PBR Plan to MRP, the wording used for the guiding principles in the proposed MRPs is the same as that used in the 2014-2018 PBR Applications. Also, in the guiding principles for the proposed MRPs, FortisBC has provided additional details described as "Elements of Proposed Multi Year Plan" for each of the principles.

Provided below for comparison is an excerpt from page 43 of FEI's 2014-2018 PBR Application[36], stating the guiding princples.

The guiding principles are, in no particular order:

> **Principle 1:** The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.
>
> **Principle 2:** The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.
>
> **Principle 4:** The PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.
>
> **Principle 5:** The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

On pages 15–16 of the FEI PBR Decision, the BCUC stated the following:

> The Commission Panel is in agreement with Fortis that the revenues driven by the PBR formula must provide utilities the opportunity to earn a fair return. The Panel also acknowledges that changes to individual plan components "may change the overall risk/reward profile of the PBR Plan."
>
> …

[36] Also on Page 39 of FBC's 2014-2018 PBR Application.

Fortis has put forward a PBR plan with numerous elements. As outlined by Dr. Overcast, each of the elements needs to be scrutinized carefully. This is to ensure they are reasonable and do not favour either the Companies or the ratepayer. Determinations resulting from this evaluation need to achieve a proper balance of risks and rewards between the Companies and the ratepayer and reflect current reality.

In Appendix B to the Workshop Materials, FortisBC provides a comparison of FEI and FBC's proposed MRPs and the Current PBR Plans.

19.8 Please provide a detailed discussion of each of the implications of the differences between the Current PBR Plans and the proposed MRPs, including the implications of changes to individual plan components. Please include the description of the implications as an additional column to the table in Appendix B to Exhibit B-2 and address, among other things, the following:

- Whether the proposed change increases the potential risks to FEI/FBC and its shareholders, to the ratepayers, or has a neutral impact;
- Whether the proposed change increases the potential rewards to FEI/FBC and its shareholders, to the ratepayers, or has a neutral impact;
- Whether the proposed change increases, decreases or has a neutral impact on FEI/FBC's efficiency incentives to create a productivity improvement culture; and
- Whether the proposed change increases, decreases or has neutral impact on stakeholders' ease of understanding.

Response:

MRP incentives and their associated risk and rewards are interconnected and need to be viewed together. Ordinarily, MRP incentives depend on the type of costs subject to the incentive framework, the length of the plan, the decoupling of cost and revenues, and the type of the earnings sharing mechanism applied (if any). The proposed MRPs have for the most part maintained the Current PBR Plans' structure and other than a few items described below maintain the same level of incentives and associated risks and rewards. The requested descriptions are provided below, with changes highlighted in yellow in the Proposed Plans column.

Item		2014-2019 Plans		Proposed Plans		Comparison of risk/rewards/incentives and ease of understanding
		FEI	FBC	FEI	FBC	
Term		Six years (2014-2019)		Five years (2020-2024)		This change has no impact on the risks/rewards or incentives because for all practical matters the term of the Current PBR Plans were five years as well (Refer to Section C1.2).
Formula	O&M	$OM_t = OM_{t-1} * [1 + (I-X)] * (1+G/2)$ G = Percentage growth in average number of customers		$OM_t = UCOM_{t-1} * (1 + I) * (G_t)$ G = Avg number of customers Customer growth forecast annually with true-up for actual in the following year(s).		The proposed changes (the elimination of 0.5 multiplier and the use of true-up) will improve the accuracy of the O&M formulas to estimate Utilities' needed O&M during the MRP term and as such improve the balance of risks and rewards for both utilities and customers (more accurate formula means less risk of windfall losses or surpluses which reduce the risk for all parties involved). FortisBC believes that the unit cost approach is more transparent than the O&M approach used for the Current PBR Plan as stakeholders can monitor the unit cost performance directly and therefore will improve the ease of understanding for all stakeholders.
	Capital	$Allowed\ Cost_t = Cost_{t-1} * (1+I-X) * (1+G/2)$ Three categories: (i) Growth capital, (ii) sustainment capital (iii) other capital	$Allowed\ Cost_t = Cost_{t-1} * (1+I-X) * (1+G/2)$ Three categories: (i) Growth capital, (ii) sustainment capital (iii) other capital	5 year forecast; Exception: Growth capital $GC_t = UCGC_{t-1} * (1+I) * G_t$ G = Gross customer additions Customer growth forecast annually with true-up for actual in the following year(s).	5 year forecast	FortisBC's assessment of the proposed changes to FEI's growth formula (the elimination of 0.5 multiplier, use of gross customer additions, and the use of true-up) is similar to the one provided for O&M formulas above (better accuracy, improve transparency and no impact on incentives to find efficiencies). The proposed forecast approach to capital expenditures will improve transparency and ease of understanding, as stakeholders are able to scrutinize the Companies' capital plan in more detail than what would have been possible under a formula approach. The forecast capital approach will better address the lumpy nature of capital investments and as such will be a more accurate representation of the Companies' actual capital requirements. Forecast capital is subject to the same level of incentives as formula capital. This is because similar to the formula approach any variance is shared through the earnings sharing mechanism.
		G = Service line additions for Growth capital, average number of customers for Sustainment and Other capital	G = Average number of customers			

Item	2014-2019 Plans		Proposed Plans		Comparison of risk/rewards/incentives and ease of understanding
	FEI	FBC	FEI	FBC	
I-Factor	Composite index: 55% AWE:BC + 45% CPI:BC		No change; Composite index: 55% AWE:BC + 45% CPI:BC		-----
X-Factor	Fixed at 1.10% for the entire PBR term	Fixed at 1.03% for the entire PBR term	No X-Factor (Implied zero percent X-Factor)		The value of X-factor has no impact on the incentives of the plan. Please refer to the response to BCUC IR 1.6.3. Not relying on a TFP study will improve ease of understanding (refer to BCUC IR 1.17.5)
Y-Factor	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.		Yes, Flow-through deferral account (although flow-through items are more limited) as well as a number of other deferral accounts such as DSM expenses, cost of gas/power supply, pension/OPEB expense.		Limiting the flow-through items (such as subjecting depreciation expense to incentive framework) will increases the plans' risks and rewards and therefore the incentives. FortisBC does not believe that this change will have any major influence on ease of understanding.
Z-Factor	Available for prudently incurred costs caused by exogenous factors.		Available for prudently incurred costs caused by exogenous factors.		--------
	Materiality threshold: 0.5% of 2013 base O&M which equalled $1.15 million.	Materiality threshold: 0.5% of 2013 base O&M which equalled $0.301 million.	No materiality threshold (prudently incurred costs should not be subject to a materiality threshold)		As a matter of regulatory principle, utilities should be able to recover their prudently incurred costs. However, in practice, the process for considering exogenous factors has been well established through the Annual Reviews and the BCUC has the opportunity to consider the appropriate treatment of such costs and the Utilities' recognizes the regulatory efficiency objectives in making their requests. Therefore, FortisBC does not expect any major change in risk/reward profile as was confirmed in the BCUC 2016 Cost of capital decision.
ESM	50/50 symmetric sharing for variances in formula O&M and for earnings on formula capex variances within a dead band.		50/50 symmetric ROE sharing		The ESM maintains its 50/50 symmetric sharing nature and the changes recommended are administrative and proposed to accommodate the changes in other sections such as flow-through items. As such, there is no change in risks and rewards or incentives. The proposed ESM will improve the ease of administration and understanding

Item	2014-2019 Plans		Proposed Plans		Comparison of risk/rewards/incentives and ease of understanding
	FEI	FBC	FEI	FBC	
Other 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		Dead band for capital formula - No capital dead band is proposed as the capital for majority of the capital spending categories is forecast and the proposed ESM and off-ramp provisions can sufficiently mitigate the risks to customers and the Utilities.		As explained above, the use of a modified Growth capital formula (for FEI) and the forecast of capital in other categories will improve the accuracy of the allowed capital amounts. This increased accuracy will allow for elimination of the capital dead band. Nevertheless, the elimination of this safeguard mechanism will have an upward impact on the plans' risk/reward profile and incentives. The elimination of the dead band will improve ease of understanding, as this mechanism was a source of confusion in annual reviews.
	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.		Off-ramp provision (No change) 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		An ROE add-on to the Approved ROE for the two years after the end of the Plans' term calculated as 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).		The ECM will have a positive impact on the incentives in the last two years of the plan. This will be beneficial for both Utilities and customers (customers will benefit from the utility's continuous efficiency focus in the latter years of the plan). There is no risk attached to the ECM. The proposed ECM is relatively easy to understand and will not have a significant impact on ease of understanding

Item	2014-2019 Plans		Proposed Plans		Comparison of risk/rewards/incentives and ease of understanding
	FEI	FBC	FEI	FBC	
Incremental Capital	Available through CPCN process	Available through CPCN process plus specific major non-recurring projects	Available through CPCN process	Available through CPCN process	The proposed changes to capital formulas and the possibility of reviewing the forecasts for the last two years in year three means that FBC does not need to include the non-recurring projects in its major incremental capital request. Assuming the proposed review process is approved, this will have no impact on risk/reward profile or incentives. The review of capital plan in year three for any needed updates can improve customers' understanding during the MRP term.
	Materiality threshold of $15 million	Materiality threshold of $20 million	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	Yes, Included nine SQIs and four informational indicators. Adjustments to specific benchmarks, thresholds and annual basis of calculation.	Yes, Included eight SQIs and four informational indicators. Adjustments to specific benchmarks, thresholds and annual basis of calculation.	The proposed changes are either minor in nature or implemented after discussions with intervener groups to address their specific concerns. FortisBC is of the view that these changes do not affect the plans' risk/reward profile or the incentives in a major way; however, the more stringent targets put upward pressure on risk of penalties if the targets are not achieved. The addition of some new SQIs can improve transparency.
Clean Growth Innovation Fund	None		An innovation Fund aimed at accelerating investments in new technologies is proposed.		As explained in response to BCUC IR I.71.4, FortisBC expects that the proposed Fund will directly benefit ratepayers by achieving performance breakthroughs and supporting the transition to a lower carbon economy. As is the case for any other R&D initiative, the ultimate risk to ratepayers would be that no significant innovation is achieved; however, looking at the results of innovation funds in other jurisdictions, this risk is minimal. Please also refer to BCUC IR 1.77.4 The proposed Fund's ease of understanding and transparency issues are discussed in BCUC IR 1.73.10.

Item	2014-2019 Plans		Proposed Plans		Comparison of risk/rewards/incentives and ease of understanding
	FEI	FBC	FEI	FBC	
Targeted Incentives	None		-Yes; -Growth in RNG -Growth in NGT -GHG Emissions Reduction (Customer and internal) -Customer Engagement	Yes; -Customer Engagement -Growth in EV Transportation -Power Supply Incentive	The Targeted Incentives are positive-only for both Utilities and customers with no incremental risks. That is, the proposed incentives are aligned with the public interest and can increase demand or reduce costs for customers. Further, the Targeted Incentives are designed to promote initiatives that can mitigate the long-term risks discussed in the response to BCUC IR 1.2.4 for Utilities and customers. FortisBC's proposed ROE adder approach to these incentives is transparent and easy to understand.

1

19.9 When taking into consideration the following proposals in FortisBC's MRPs – (i) the lack of productivity factor applied to formula O&M and growth capital (for FEI), (ii) the removal of the 50 percent reduction to the growth factor for O&M and growth capital (for FEI), (iii) the inclusion of positive only targeted incentives, and (iv) the inclusion of an innovation fund – please discuss whether the balance of rewards has been shifted away from or towards FortisBC's shareholders and/or away from or towards ratepayers.

Response:

Please refer to the response to BCUC IR 1.19.8.

20.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN

Exhibit B-1, Section C1.4, pp. C-6 – C-10

Growth Factor

On page C-6 of the Application, FortisBC states the following: "Under the proposed unit cost approach to O&M, FortisBC proposes to maintain the average number of customers 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."

20.1 Please explain why FortisBC does not propose to use the average number of customers as the growth factor for growth capital as opposed to gross customer additions.

Response:

As described in Section C3.3.1.1 of the Application, the primary cost driver for Growth capital is the addition of customers, not the average number of customers. The average number of customers includes customers that move in and move out of premises; move-ins and move-outs do not typically require capital expenditures. Therefore, using gross customer additions provides for a better index for Growth capital costs.

20.2 Please confirm, or explain otherwise, that the average number of customers was used as the growth factor for FBC's growth capital in the Current PBR Plan.

Response:

FBC does not have a growth factor specific to Growth capital under the Current PBR Plan. FBC confirms that the growth factor applicable to its aggregate capital formula envelope is based on the average number of customers.

20.2.1 If confirmed, please explain why average number of customers was an appropriate growth factor for FBC's growth capital in the Current PBR Plan but is not considered appropriate for FEI's growth capital for the proposed MRP.

Response:

The challenges resulting from the use of formulas to forecast capital expenditures in the Current PBR Plans are discussed in Section B2.3.2 and Appendices B8-1 and B8-3 of the Application, and confirm that the use of average customers was not an appropriate growth factor for any capital spending during the terms of the Current PBR Plans. Given these challenges, FortisBC determined that a formula is not the most appropriate approach for FBC's Growth capital (or Sustainment and Other capital for either utility) for the proposed MRPs.

Please refer to the response to BCUC IR 1.8.13 and 1.20.1 which explains why gross customer additions is the appropriate driver for FEI's Growth capital.

21.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN

Exhibit B-1, Section C2, pp. C-14 – C15

O&M Base and Formula

On page C-14 of the Application, FortisBC states:

> 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.

21.1 Please explain why FortisBC is proposing to use "O&M per customer" as the starting point for establishing the Base O&M as opposed to the approach used in the Current PBR Plans for determining the Base O&M (i.e. total O&M instead of per-customer O&M).

Response:

Using O&M per customer as proposed in the Application or applying a growth factor to total O&M as in the Current PBR Plan produces the same resulting total O&M since the variable that determines the total O&M is average customers in both cases. Using O&M per customer provides both:

- a transparent year-over-year view of how much the Companies are forecasting to spend on a per-customer basis; and
- a transparent true-up mechanism, where the Companies are responsible for O&M unit cost variances and both the Utility and customers are held whole for customer count-related forecast variances.

The following table shows that both methods produce the same total O&M (lines 10 and 15). FortisBC has used a hypothetical forecast of average customers (AC) and a hypothetical forecast of CPI & AWE inflation for illustrative purposes.

Line	Particulars	Reference	Base 2019	MRP years--> 2020	2021	2022	2023	2024
1	O&M ($000)		256,000					
2	AC		1,024,000					
3	O&M per customer	Line 1 / Line 2 x 1000	250					
4								
5	Forecast of AC	Random	1,024,000	1,034,000	1,047,000	1,058,000	1,067,000	1,080,000
6	Growth Factor	Line 5 / Prior year Line 5		100.98%	101.26%	101.05%	100.85%	101.22%
7	Inflation (CPI & AWE)	Random		2.10%	1.80%	2.30%	2.20%	2.00%
8								
9	**Current PBR method**							
10	Total O&M ($000)	Prior year Line 10 x Line 6 x (1 + Line 7)	256,000	263,929	272,057	281,239	289,871	299,271
11								
12	**Proposed Method**							
13	O&M per Customer (inflated)	Prior year Line 13 x (1 + Line 7)	250.00	255.25	259.84	265.82	271.67	277.10
14	AC	Line 5	1,024,000	1,034,000	1,047,000	1,058,000	1,067,000	1,080,000
15	Total O&M ($000)	Line 13 x Line 14 / 1000	256,000	263,929	272,057	281,239	289,871	299,271
16								
17	Difference	Line 10 - Line 15	-	-	-	-	-	-

21.2 Please explain if using per-customer O&M yields a different Base O&M amount and a different annual formulaic O&M amount than if total O&M were used. As part of this response, please provide a numerical example to show the calculation of Base and annual formulaic O&M under the proposed per-customer approach and under the current total O&M approach (assume that both approaches are inflated using the proposed inflation and growth factors).

Response:

Please refer to the response to BCUC IR 1.21.1.

On page C-14 of the Application, FortisBC states: "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, due to permanent savings from the Current PBR Plans being embedded in the O&M levels going forward."

Footnote 115 on page C-14 of the Application provides the following information for FEI and FBC on an inflation adjusted basis:

- 2019 Total O&M per customer - $285 (FEI); $439 (FBC)
- 2013 Total O&M per customer - $314 (FEI); $495 (FBC)
- 2019 Formula Base O&M per customer - $250 (FEI); $416 (FBC)
- 2013 Actual Formula O&M per customer - $286 (FEI); $457 (FBC)

21.3 Please provide the non-unit inflation-adjusted O&M comparisons for FEI and FBC for 2013 and 2019 (i.e. not on a "per customer" basis).

Response:

FortisBC provides the requested information below.

Non-Unit, Inflation Adjusted to 2019 dollars, O&M ($000)	FEI	FBC
Total O&M 2019	$292,282	$60,892
Total O&M 2013	$297,466	$63,660
Formula Base O&M 2019	$256,685	$57,686
Formula Base O&M 2013	$270,276	$58,779

On page C-15 of the Application, FortisBC states that it will "maintain this discipline and rigour in its approach to managing O&M expenditures in the Proposed MRP."

21.4 Please discuss whether the incentives to maintain the same level of discipline and rigour with regard to O&M spending may be decreased under FortisBC's proposed inflation-indexed approach to O&M, as this proposed approach does not include any productivity factor.

Response:

The Traditional Incentives to achieve efficiency gains are not affected by the choice of a particular value of the X-factor, whether it is negative, zero or positive. Please refer to the response to BCUC IR 1.6.3.

22.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN

Exhibit B-1, Section C2, pp. C-16 – C-17; FEI PBR Application proceeding, Exhibit B-1, Table C3-5, p. 133

O&M Base

On pages C-16 and C-17 of the Application, FortisBC provides examples of cost pressures anticipated during the proposed MRPs for FEI and FBC which it is not requesting incremental funding for in the proposed Base O&M.

22.1 For each of FEI and FBC, please provide the following information:

- The annual and cumulative incremental O&M impact of the cost pressures expected during the proposed MRP term;
- The annual and cumulative incremental FTE impact of the cost pressures expected during the proposed MRP term; and
- A detailed cost breakdown and description by department of each of the cost pressures described on pages C-16 and C-17 for each year of the MRP term. Please clearly identify the amount of each cost pressure and which department it is impacting.

Response:

For the examples of cost pressures that were identified on page C-16, FortisBC has prepared the table below, showing annual expected increases for those specific items during the MRP term. The cumulative impact of the items listed if they were approved as part of the Base O&M for the MRPs would be approximately five times (i.e., five years for the proposed MRPs) the annual values stated.

As noted in the Application, FortisBC is not requesting any annual incremental funding in the proposed Base O&M for these items, or for the other items that were not listed in the Application but will similarly provide cost challenges during the MRP term. FortisBC has not prepared a forecast of costs for the upcoming MRP term because it has proposed an index-based approach to O&M, and therefore is not able to provide a comprehensive list of cost pressures anticipated that will be managed within the index-based O&M.

Company	Cost Pressures listed on pages C-16 and C-17	Department Affected	$ millions
FEI	Additional resources to enable continued investment	Operations	$ 0.80
FEI	Operations transition and succession planning	Operations	$ 0.70
FBC	Increased engineering and technology staffing	Operations and Engineering	$ 0.22
FEI and FBC	Increased general and administrative costs	Finance, HR, Procurement	$ 0.64
FEI and FBC	Increased costs in meeting evolving municipal regulations	Operations	$ 0.20
FEI and FBC	Increased environmental and safety programs	Safety	$ 0.20
	Total Cost Pressures listed		$ 2.76

Descriptions and details of the cost pressures are outlined on page C-16 and C-17. The expected cost pressures have been identified in relation to recent years' expenditures and funding available for the line items.

As the stated values have been prepared at a high level and estimated only, the incremental FTE impact of the cost pressures is not known.

With regard to FEI, FortisBC states the following on page C-16 of the Application:

> Additional resources to enable continued investment in assets and customer service…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.

22.2 Please provide the percentage of the costs described in the above preamble which would likely be charged directly to capital and the percentage that would be included in O&M.

Response:

FEI estimates that approximately 40 percent of the costs will be charged directly to capital and the remaining 60 percent will be included in O&M. Of the amounts included in O&M, approximately 15 percent represents the indirect costs used to support capital and used to derive the capitalized overhead rate described in Section D6 of the Application.

22.3 Please explain how the costs charged directly to capital would be accounted for during the MRP term and whether the capital portion of these incremental costs have been factored into the proposed formula and/or forecast capital expenditures.

Response:

The costs charged directly to capital are accounted for during the MRP term in the capital forecast and are not included in the index-based O&M.

The incremental indirect O&M costs incurred to support capital activities are part of the index-based O&M as shown in Table C2-1: FEI 2019 Base O&M. The proportion of those indirect costs that supports capital activities and that is included in 2019 Base O&M is then captured in the allocation of capitalized overheads; the result is Net O&M. The allocation of overheads capitalized from O&M to capital occurs outside of the Base O&M, and will increase (be added to) the capital expenditures as a separate line item (it is not shown in the tables included in Section C3).

To summarize, the capitalized overheads are allocated to capital expenditures as a separate line item such that the FEI Growth capital outlined in Section C3.3.1.3.1 and the forecasted Sustainment and Other capital expenditures for 2020-2024 shown in Table C3-5 do not include the capitalized overheads allocation.

With regard to FEI, FortisBC states the following on page C-16 of the Application:

> 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.

22.4 Please estimate the number of employees that FEI is expecting to retire during the proposed MRP term and the associated decrease in labour costs related to those retirements.

Response:

FEI estimates that approximately 370 employees will retire during the proposed MRP term. This estimate is based on historical average age of retirement with an unreduced pension. This is expected to result in an increase of approximately 13 FTEs and $1.3 million for each year of the proposed MRP term.

FEI does not anticipate a decrease in labour costs related to retirements as the employees retiring need to be replaced. Additionally, labour costs will continue to increase due to factors such as negotiated general increases, labour market inflation and continued retirement transition to provide succession during the proposed MRP term.

22.5 Please provide the expected net impact on FTEs in the Operations area due to employee retirements and filling of positions.

Response:

Operations is expecting approximately 200 retirements over the proposed MRP term. Operations anticipates the net impact of these retirements on FTEs in Operations will be an average increase of approximately 7 FTEs for each year of the proposed MRP term.

22.6 Please explain why the situation described in the above preamble is not also an issue for FBC.

Response:

Employee transition and succession is an issue for both FBC and FEI.

In Section C2.3 of the Application (the referenced page C-16), FortisBC discussed examples of areas where cost pressures would be absorbed by the Utilities, and one example was that FEI will manage cost pressures related to Operations employee transition and succession for the proposed MRP term, and was not requesting incremental O&M funding as a result.

In the case of FBC, a similar situation exists concerning transition and succession for employees in the Operations area, but FBC does require some incremental O&M funding as discussed on page C-48 of the Application. In its incremental O&M funding requests, FBC has

included funding for the Network Operations Apprentice program in part to address the issue. FBC plans to hire additional apprentices to help develop enough International Trade Administration apprentices to meets its anticipated needs. The additional apprentices will also help with transition and succession for the Operations area at FBC.

On pages C-16 and C-17 of the Application, FortisBC identifies the following cost pressure 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 the 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.

22.7 Please explain in detail for each of FEI and FBC the expected increased compliance requirements, changes in accounting standards and supporting audits.

Response:

FortisBC notes that these requirements are examples of the items that FEI and FBC are not requesting incremental funding for, and will manage by finding efficiencies in other areas.

The level of forecasted Regular capital expenditures and Major Projects over the term of the MRP will require an increase in compliance, accounting, financial reporting, tax and financing requirements, which are managed by FortisBC's Finance department. Increased capital expenditures are expected to increase the following Finance department activities:

- accounting processes and transactions for asset additions and retirements, while executing and creating new internal controls over financial reporting (ICFR);
- managing of capital project budgets and forecasts;
- raising cost-effective debt and manage equity financing requirements while ensuring compliance with debt agreements and rating agencies' credit metrics;
- corporate income tax analysis to ensure appropriate capital expenditure deductions are taken, including the application of existing and new Capital Cost Allowance calculations;

- commodity tax analysis to ensure appropriate GST and PST are applied on capital expenditures and assessing the availability of claiming Scientific Research and Experimental Development tax credits;
- increased application of existing and new accounting guidance under USGAAP.

22.7.1 As part of the above response, please explain why FortisBC expects these activities to be higher during the MRP than during the Current PBR Plans.

Response:

Please refer to the response to BCUC IR 1.22.7.

22.8 With regard to the cost pressures described related to the Human Resources and Finance departments, please explain if these costs will directly impact both FEI and FBC or if the costs will form part of the shared/corporate services allocations.

Response:

Under the proposed shared services model for allocation of shared O&M costs between FEI and FBC, the described cost pressures and costs will form part of the shared services O&M and be allocated to FEI and FBC using a cost driver approach. Similarly, the proposed corporate services allocation model will result in certain of the described cost pressures and costs being allocated to FEI and FBC based on the Massachusetts formula.

The corporate and shared service methodologies proposed by FortisBC will result in the Utilities being indifferent as to whether additional resources are hired, or non-labour costs are incurred, by either FEI or FBC. This is because the final cost allocation will be the same and each utility will receive its fair share of costs.

On page C-17 of the Application, FortisBC identifies the following cost pressure for FEI and FBC: "Increased costs will be incurred in meeting evolving municipal regulations such as additional permitting, working arrangements, and restricted working hours."

22.9 Please clarify what FortisBC means by "working arrangements" and "restricted working hours" and how these factors impact costs for each of FEI and FBC.

Response:

Working arrangements are the requirements that FortisBC needs to fulfil in order to meet municipal requirements and achieve approval to proceed with work. They include co-ordination with other planned municipal activities, traffic plans, road closures, increased mobilization and demobilization, and additional resource coordination to meet restricted working hours.

Restricted working hours means working during specified times in the evening, overnight or on weekends to limit impacts on traffic and avoid obstructing arterial routes during high traffic periods. These factors increase costs by extending the planning time for work, increasing the labour costs for work performed outside of normal working hours, and requires more frequent work mobilization and demobilization.

On page C-17 of the Application, FortisBC identifies the following cost pressure for FEI and FBC: "Increased environmental and safety program requirements."

22.10 Please explain in detail the expected increased environmental and safety program requirements for each of FEI and FBC.

Response:

FortisBC notes that these requirements are examples of the items that FEI and FBC are not requesting incremental funding for, and will manage by finding efficiencies in other areas.

Environmental, Health and Safety (EH&S) regulatory requirements at the Federal, Provincial and Local Government levels are continually evolving and require increasing levels of reporting and oversight. EH&S assessments, investigations, permitting and approvals, emissions management and reporting are areas that are expected to continue to require additional support. Additional training, monitoring, inspecting, operational (on the job) learning, and auditing will be required to ensure compliance with evolving regulatory requirements, including:

- Field-focused advisors will coach and mentor field-based employees through review and development of safe work practices supported by task-based hazard analysis and quality safe work planning and environmental risk management.
- Robust and effective audit programs will provide flexibility to evaluate key business area priorities, test the resilience of the EH&S management systems as well as provide assurance of continued compliance.
- Monitoring and inspection processes will provide source data to support new and existing reporting requirements, ensure standards are being met as well as provide information in response to due diligence requests.
- Training will be developed to support and sustain the ergonomic safety program focusing on reduction and prevention of worker musculoskeletal injuries.
- Specific safety enhancements through implementation of safety programs will focus on high risk, contractor management, road safety, leading safety indicators, human and organizational performance and further development of frontline safety leadership.

On page C-17 of the Application, FortisBC states the following:

> 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 by a CPI-based inflation factor.

22.11 Please explain, with reference to each of FEI and FBC, if the costs to insure and operate vehicles, fees for rights of way, and/or facilities lease contract increases were higher than CPI-based inflation during the Current PBR Plan terms.

Response:

Vehicle Costs

For FEI and FBC, during the term of the Current PBR Plan, total operating costs for vehicles including fuel and insurance have risen approximately 3 percent per year (over the period 2013 to 2018), higher than CPI. The increase in costs was affected by moderate gasoline price increases and increases in ICBC insurance rates for vehicles. For FEI, contributing to the

higher operating costs was an increase in the number of vehicles added to the Fleet to support Operations activities.

Facilities Contracts

During the term of the Current PBR Plan, FEI lease contract increases have been higher than CPI. FEI currently has lease contracts for 25 locations throughout the Province. The lease contracts have stepped rate increases, renewal and expiry terms that affect the cost of the contract. Generally, the leases have a 5 year term and on renewal, increases of a minimum 10 percent due to the length of the contract can be expected. Market demand for specific areas also affects the rate increase negotiated.

As part of the management and operation of the facilities, FEI and FBC have contracts with third parties to provide a wide range of services. Examples of these services are janitorial, landscaping and security. The provincial government implemented increases to the minimum wage in recent years including 2017, 2018 and 2019. These increases have been higher than CPI and resulted in contract renewals higher than inflation.

Fees for Rights of Way

In situations where FEI and FBC are not able to acquire a statutory right-of-way, FEI and FBC enter into other forms of agreement. These other forms of agreement typically have recurring rents or fees which are subject to review and adjustment periodically. The mechanism for the fee adjustment differs across specific agreements with some stipulating CPI increases and others requiring an independent real estate appraisal. In addition to the recurring payments for its rights of way agreements, FEI incurs other costs for supporting the agreements including legal, appraisal and survey fees which are required when agreements are renewed.

During the term of the Current PBR Plan, most FEI and FBC agreements requiring renewal were subject to increases higher than CPI, reflective of the strong real estate market in the Province.

22.11.1 Please provide examples of other costs, if any, which were higher than CPI-based inflation during the Current PBR Plan terms.

Response:

Some other examples of costs that have been higher than CPI-based inflation during the Current PBR Plan term include:

- Benefit costs increases due to an aging workforce, the prevalence of chronic disease, and mental health conditions;
- Postage costs for billing customers have risen an average of 3 percent per year from 2014 to 2019; and
- Information System and odourant costs increases resulting from the decline in the value of Canadian currency for US dollar denominated expenditures.

During the Current PBR Plan term, FortisBC has successfully managed these cost increases, with its broad based productivity focus and the benefits of specific productivity initiatives undertaken. FortisBC expects during the term of the proposed MRPs that cost items like these and other similar items will surface.

22.11.2 If FEI and FBC did experience cost increases higher than CPI-based inflation during the Current PBR Plan terms, please explain how each utility managed these cost pressures, particularly given the inclusion of the productivity factors, while still managing to achieve annual savings in O&M.

Response:

As discussed in the Annual Reviews, FortisBC maintained a broad-based, ongoing focus on productivity during the term of the Current PBR Plans. Departments and employees were asked to review the way they operate to streamline processes and make it more efficient for our customers to do business with us. Expenditures and filling of vacancies were reviewed. This broad-based focus on productivity was successfully maintained through the Current PBR Plans and contributed to achieving the required productivity factors, managing cost pressures and realizing O&M savings.

In addition to the broad-based productivity focus, both Companies undertook specific initiatives to reduce costs. FEI completed a number of major productivity initiatives such as Regionalization and Project Blue Pencil, which resulted in efficiencies and contributed to a reduction in O&M costs. Similarly, while not on the same scale as FEI, FBC also undertook a number of initiatives to achieve efficiencies and cost savings.

The combination of the above efforts have enabled FortisBC to successfully manage O&M expenditures within the allowed formula funding containing an embedded productivity factor while achieving O&M savings which have been shared between the Companies and customers.

However, as we near the end of the term of the Current PBR Plans, FortisBC continues to be faced with the increasingly difficult challenge of finding new productivity opportunities to meet the annual savings embedded in the formula and to sustain the level of incremental O&M savings achieved in recent years.

22.12 Please explain why FortisBC is not requesting incremental funding during the proposed MRP term for the specific cost pressures identified on pages C-16 and C-17 of the Application but it is requesting incremental for other types of cost pressures. How did FortisBC determine which costs it would manage under the existing funding level and which costs required incremental funding? Please explain.

Response:

Please refer to the response to BCUC IR 1.29.1.1.

22.13 Please provide a list similar to the information provided on pages C-16 and C-17 of the Application of the anticipated cost reductions and reduced cost pressures during the Proposed MRP term for FEI and/or FBC.

Response:

FortisBC has not identified a list of anticipated cost reductions and reduced cost pressures that will be using to offset the expected cost pressures during the MRP period; nor has it prepared a comprehensive list of all cost pressures it will face during the MRP period. The list that was provided was meant to be illustrative only.

Instead, FortisBC will be maintaining its focus on productivity which it has successfully fostered during the Current PBR Plan term, and relying more on its “doing more with the same” approach to manage cost pressures, recognizing also that finding new productivity opportunities (i.e., cost reductions) is increasingly difficult, as the Companies have achieved efficiencies after a number of years of successfully implementing cost savings.

While it does not have a list of anticipated cost reductions that will offset the expected cost pressures, FortisBC believes that the framework for the proposed MRPs provides the necessary incentive for the Companies to continue their focus on productivity and manage O&M costs successfully, by sharing equally in any savings achieved.

In the FEI PBR Application, FEI provided the following table on page 133:

Table C3-5: Departmental O&M Forecasts ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	69,016	71,062	73,298	75,084	77,253	79,648
Customer Service	44,398	45,353	46,323	47,873	49,068	50,956
Energy Solutions & External Relations	20,721	23,275	23,771	24,343	24,961	25,721
Energy Supply & Resource Dev	4,440	4,738	4,918	5,040	5,175	5,350
Information Technology	23,768	24,392	24,911	25,487	26,097	26,809
Engineering Services & PM	17,018	17,736	17,766	18,214	18,692	19,325
Operations Support	13,111	13,698	14,013	14,386	14,794	15,313
Facilities	9,504	9,959	10,170	10,469	10,705	11,065
Environment Health & Safety	2,872	2,934	2,997	3,069	3,147	3,242
Finance & Regulatory Services	15,079	15,401	15,728	16,101	16,502	16,987
Human Resources	9,192	9,399	9,601	9,841	10,102	10,431
Governance	8,028	8,371	8,742	9,135	9,544	9,974
Corporate	(6,161)	(6,385)	(6,478)	(6,600)	(6,726)	(6,914)
	230,985	239,933	245,761	252,443	259,315	267,907

22.14 Please provide a similar table for FEI and for FBC detailing the annual O&M forecast by department for each year of the proposed MRP term.

Response:

FortisBC (FEI and FBC) is proposing an Index-Based formula approach based on total O&M per customer to determine overall O&M funding for the MRP period. As a result, FortisBC has not prepared a forecast of O&M over the term of the proposed MRPs.

22.14.1 For each of FEI and FBC, please specifically identify the cost pressures described on pages C-16 and C-17 of the Application within the annual forecasts.

Response:

Please refer to the response to BCUC IR 1.22.14.

22.14.2 For each of FEI and FBC, please specifically identify each of the adjustments and proposed new funding items for the MRP term described in Table C2-1 and Table C2-14 of the Application within the annual forecasts.

Response:

Please refer to the response to BCUC IR 1.22.14.

23.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN

Exhibit B-1, Section C2; Exhibit B-1-1, Appendices A3-1, A3-2; FEI PBR proceeding, Exhibit B-1, p. 123; FBC PBR proceeding, Exhibit B-1, p. 112

Current PBR Plan O&M

Appendices A3-1 and A3-2 of the Application provide a breakdown of the 2013-2017 Actual O&M expenses for FEI and FBC, respectively.

23.1 Please update Appendices A3-1 and A3-2 to include Actual 2018 amounts and Projected 2019 amounts.

Response:

Please refer to Attachment 23.1 for updated Appendices A3-1 and A3-2.

The Actual O&M Expenses view reported in Appendices A3-1 and A3-2 represents the O&M view reported in the BCUC Annual Report.

For FBC, the updated Appendix A3-2 includes 2018 Actuals but only the 2019 Projected Gross amount. Although FBC records costs in a manner that permits it to restate actuals in the Uniform System of Accounts (USOA) format, the USOA is not the way that FBC prepares or manages its internal budgets. As such, FBC does not have forecasts at the level of detail that would enable it to provide Projected 2019 amounts in the USOA format as reported in Appendix A3-2.

FEI provided the following table on page 123 of the PBR Application:

Table C3-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Operations	54,444	55,756	59,806	58,599	63,509	63,189
Customer Service [1]	53,278	56,575	40,737	49,115	41,825	52,452
Energy Solutions & External Relations	14,636	15,456	18,075	17,509	19,215	18,181
Energy Supply & Resource Dev	2,075	3,409	3,488	3,664	4,000	3,738
Information Technology	17,320	18,654	23,442	24,553	24,217	25,379
Engineering Services & PM	13,566	14,329	13,599	16,705	15,456	16,956
Operations Support	10,916	10,580	11,038	12,132	11,867	12,990
Facilities	7,329	6,835	9,563	9,509	9,249	9,259
Environment Health & Safety	2,427	2,445	2,481	2,749	2,681	2,999
Finance & Regulatory Services	12,177	12,064	12,149	13,129	13,279	14,184
Human Resources	8,823	8,170	8,610	8,983	8,458	8,511
Governance	7,368	7,895	7,366	7,602	7,935	7,935
Corporate	2,158	1,439	1,915	2,743	(358)	230
	206,518	213,606	212,269	226,993	221,333	236,003

1 Excludes deferred Customer Service O&M for 2012 Actual and 2013 Projection

23.2 Please provide the same breakdown of O&M by department for Actual 2013 through 2018 in a format similar to Table C3-1 in the FEI PBR Application.

Response:

Below is the breakdown of FEI O&M by department for Actual 2013 through 2018.

O&M by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Operations [2]	76,169	80,224	83,463	85,682	85,894	94,603
Customer Service [1]	40,912	45,493	40,121	38,481	39,715	39,475
Energy Solutions & External Relations [3]	21,376	21,935	24,974	25,190	26,081	28,004
Energy Supply & Resource Dev	4,031	4,196	4,513	4,590	4,624	4,453
Information Technology	25,331	26,296	28,229	26,529	24,521	25,240
Engineering Services & PM	15,814	15,383	16,379	16,382	15,496	16,556
Operations Support	11,917	13,459	13,446	13,197	12,503	12,749
Facilities	9,739	9,719	9,537	9,836	10,383	10,028
Environment Health & Safety	2,680	2,910	3,159	3,669	4,217	4,527
Finance & Regulatory Services	13,363	14,080	13,599	13,534	13,391	13,788
Human Resources	8,305	9,285	9,109	9,015	9,049	9,483
Governance	9,044	9,457	9,204	8,743	8,179	8,328
Corporate	11,715	5,351	4,301	4,611	5,579	4,316
Total Gross O&M	**250,396**	**257,788**	**260,034**	**259,459**	**259,631**	**271,551**

1 Excludes $14.5m deferred Customer Service O&M for 2013 Actual

Includes the following O&M tracked outside of Formula

	2013	2014	2015	2016	2017	2018
2 LNG O&M		550	624	1,438	2,944	6,547
3 NGT Stations O&M		484	1,009	1,205	1,508	2,099
3 Bio-methane O&M		417	1,085	1,154	1,567	2,634

Similar to what was provided in Table C3-1 in the FEI 2014-2018 PBR Application, the department view mirrors that of the BCUC Activity View reported in Appendix A3-1 at the department roll-up level. The BCUC Activity View (New Code of Accounts) was approved by the BCUC in Order G-15-15 and provides a basis to compare historical information for FEI.

23.2.1 If changes have occurred to any of the departments during the Current PBR Plan term, please explain these changes in detail, including if new departments have been added or departments have been removed.

Response:

Please refer to the response to BCUC IR 1.23.2.

On page 112 of the FBC Application for a Multi-Year Performance Based Ratemaking Plan for the years 2014-2018 (FBC PBR Application), FBC provided the following table:

Table C4-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Generation	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	$ 827	893	986	1,069	1,124	1,124
Information Technology	$ 2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 727	867	894	925	953	953
Finance & Regulatory	$ 3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-		-	-
Total O&M	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**

23.3 Please provide the same breakdown of O&M by department for Actual 2013 through 2018 in a format similar to Table C4-1 in the FBC PBR Application.

Response:

Below is the breakdown of FBC O&M by department for Actual 2013 through 2018.

FBC O&M by Department ($000's)	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Generation [3]	2,513	2,954	3,166	3,092	3,050	3,075
Operations [1]	20,830	20,952	20,080	19,897	20,078	20,549
Customer Service [1]	7,630	8,366	7,243	5,712	5,914	5,856
Communications & External Relations	1,426	1,507	1,433	1,343	1,423	1,442
Energy Supply	1,083	1,225	1,233	1,274	1,170	1,210
Information Systems [1]	2,806	4,388	5,112	5,379	5,006	5,022
Engineering [1.2]	2,737	3,765	4,027	4,073	4,142	5,299
Operations Support [1]	1,308	1,166	1,074	792	750	800
Facilities	3,493	2,607	2,475	2,704	2,741	2,988
Environment Health & Safety	877	900	877	1,032	898	914
Finance & Regulatory Services	4,050	4,162	3,668	3,623	3,695	3,752
Human Resources	1,835	1,915	1,855	1,731	1,695	1,878
Governance	2,658	2,543	2,513	2,364	2,796	2,772
Corporate	3,448	3,273	3,028	2,595	2,463	1,796
Total Gross O&M	**56,696**	**59,723**	**57,785**	**55,610**	**55,821**	**57,353**

	Includes the following O&M tracked outside of Formula	2013	2014	2015	2016	2017	2018
1	Advance Metering Infrastructure Costs/Savings		431	272	(1,391)	(1,246)	(1,203)
2	Mandatory Reliability Standards			375	464	53	1,024
3	Upper Bonnington Unit 3 Annual Inspection					(40)	(40)

The department view provided is similar to the view provided in Table C4-1 in the FBC 2014-2018 PBR Application. While departments have changed during the Current PBR Plan term due to management structure and reporting relationship changes which happen regularly, FBC believes it is best to provide the same department view as in the past for consistency and comparability of O&M costs.

23.3.1 If changes have occurred to any of the departments during the Current PBR Plan term, please explain these changes in detail, including if new departments have been added or departments have been removed.

Response:

Please refer to the response to BCUC IR 1.23.3.

23.4 Please provide the actual O&M FTEs and the Capital FTEs by department for the years 2013 through 2018 for FEI and FBC.

Response:

The tables below contain the actual total FTEs, split into O&M and Capital FTEs by department, for the years 2013 through 2018 for FEI and FBC. Capital FTEs include FTEs that charged and allocated their time to Capital, Deferral, third party work, intercompany and other activities (i.e., any area that is not O&M). As indicated in Appendix B7 FEI Report on Headcount and FTEs, FortisBC's Human Resource systems track employees, the positions that they occupy, and which part of the organization they belong to, but it does not track and report the FTE information by O&M and Capital by each of the departments. Therefore, the allocation to O&M and Capital FTEs by department as provided is a high level estimation of the proportion of time employees devote their time to the various activities which can vary from year to year.

FEI Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Operations [1]	669	656	629	637	664	707
Customer Service	293	266	229	215	228	223
Energy Solutions & External Relations	137	150	137	137	148	167
Energy Supply & Resource Devt [2]	42	45	43	45	45	45
Information Systems	86	83	83	84	82	83
Engineering Services & PM [3]	172	178	188	189	193	204
Operations Support [4]	141	139	138	140	142	148
Facilities	17	14	11	11	14	14
Environment Health & Safety	11	12	13	18	20	24
Finance & Regulatory Services	57	54	51	50	52	51
Human Resources	53	53	50	55	59	58
Governance	-	-	-	-	-	-
Corporate	1	1	1	1	1	2
Total FTEs	**1,679**	**1,650**	**1,573**	**1,581**	**1,648**	**1,727**

[1] includes LNG Operations

[2] includes CMAE

[3] includes Major Project FTEs supporting capital projects

[4] includes Procurement, Property Services, Measurement, Fleet and Mechanical & Logistics

FEI Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Operations	459	456	431	443	451	464
Customer Service	275	254	209	197	211	207
Energy Solutions & External Relations	86	99	91	89	95	102
Energy Supply & Resource Devt	22	21	22	22	24	24
Information Systems	72	67	66	61	59	65
Engineering Services & PM	118	115	115	121	121	128
Operations Support	83	82	80	80	86	87
Facilities	16	13	11	10	13	14
Environment Health & Safety	10	12	12	15	16	21
Finance & Regulatory Services	51	48	44	44	44	43
Human Resources	49	48	46	49	53	51
Governance	-	-	-	-	-	-
Corporate	1	1	1	1	1	2
Total O&M FTEs	**1,243**	**1,216**	**1,127**	**1,133**	**1,174**	**1,208**

FEI Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Operations	209	199	199	194	212	244
Customer Service	18	11	20	18	18	16
Energy Solutions & External Relations	52	51	46	48	54	65
Energy Supply & Resource Devt	20	24	21	23	21	21
Information Systems	14	16	17	23	22	18
Engineering Services & PM	54	63	72	68	73	77
Operations Support	58	57	59	60	57	61
Facilities	0	1	0	0	0	0
Environment Health & Safety	1	1	1	3	3	4
Finance & Regulatory Services	5	6	7	6	8	8
Human Resources	4	5	4	5	6	6
Governance	-	-	-	-	-	-
Corporate	-	-	-	-	-	-
Total Capital FTEs [1]	**435**	**434**	**446**	**448**	**474**	**519**

[1] include Capital, Deferral, Intercompany, CMAE and Others

From 2013 to 2016, the largest FTE declines were in the Customer Service area. Customer Service reductions resulted from management reorganization and reductions related to lower call volumes, in part due to annual fluctuations in weather. Included in the Customer Service reductions were positions related to Project Blue Pencil that occurred in 2015. In Operations, the Regionalization initiative (Phase 1 and 2) contributed to reductions during the same period. These decreases were offset by increased staffing in the Operations and Engineering area to meet operational and capital work requirements. Overall staffing levels continued to increase in 2017 and 2018 in response to the Companies' operational requirements, particularly in the

Operations and Engineering areas to meet customer growth and other capital requirements (i.e., Tilbury LNG Plant expansion). Increases in the Energy Solutions and External Relations over the same time period were in support of Conservation Energy Management programs and communications and stakeholder engagement activities.

FBC Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Generation	53	78	84	86	93	96
Operations	110	134	144	148	150	157
Customer Service	60	75	81	57	54	53
Communications & External Relations	7	7	7	6	6	7
Energy Management	11	11	13	14	14	14
Energy Supply	5	5	6	6	5	5
Information Systems	28	30	32	33	34	34
Engineering& PMO	67	65	67	66	66	71
Operations Support [1]	27	36	35	35	36	36
Facilities	4	3	3	4	4	4
Environment Health & Safety	5	5	5	5	6	6
Finance & Regulatory Services	21	20	19	19	20	20
Human Resources	11	13	13	11	10	11
Governance	4	4	4	4	3	3
Corporate	7	6	5	4	4	3
Total FTEs	**421**	**492**	**518**	**495**	**503**	**521**

[1] includes Procurement, Property Services, Inventory & Warehousing and Fleet

FBC Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Generation	13	19	20	23	20	24
Operations	43	53	56	56	58	61
Customer Service	51	64	62	43	42	43
Communications & External Relations	2	2	2	4	3	4
Energy Management	-	-	-	-	-	-
Energy Supply	5	5	6	6	5	5
Information Systems	16	17	19	18	19	20
Engineering & PMO	21	20	21	22	21	28
Operations Support	12	16	15	16	28	28
Facilities	4	3	3	4	4	4
Environment Health & Safety	3	3	3	2	3	3
Finance & Regulatory Services	19	18	17	15	13	14
Human Resources	9	10	9	8	6	7
Governance	3	3	3	4	3	3
Corporate	7	6	5	4	4	3
Total O&M FTEs	**209**	**239**	**242**	**224**	**229**	**247**

FBC Average FTE by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Generation	40	59	63	63	72	72
Operations	67	82	88	92	92	96
Customer Service	9	12	18	14	12	11
Communications & External Relations	5	5	4	2	3	3
Energy Management	11	11	13	14	14	14
Energy Supply	0	-	-	-	-	0
Information Systems	12	13	13	16	16	14
Engineering & PMO	45	44	46	44	45	43
Operations Support	15	21	20	18	8	8
Facilities	0	-	-	-	-	-
Environment Health & Safety	2	2	2	3	3	3
Finance & Regulatory Services	2	2	2	4	6	6
Human Resources	2	3	4	3	4	4
Governance	1	1	1	0	-	1
Corporate	-	-	-	-	-	-
Total Capital FTEs [1]	**212**	**253**	**275**	**272**	**274**	**274**

[1] include Capital, 3rd Party, Deferral, Intercompany and Others

Except for 2013 and 2014, FBC's overall FTE levels remain stable during the period. Staffing levels in 2013 and 2014 were impacted by the IBEW labour disruption. In 2016, Customer

Service Meter Reading workforce decreased as a result of the implementation of the Advanced Metering Infrastructure (AMI) Project. Since then, FTEs increased slightly particularly in Operations and Engineering & PMO to support the AMI system and new processes and as well as new headcount related to Mandatory Reliability Standards.

23.4.1 Please explain the causes of any significant annual changes.

Response:

Please refer to the response to BCUC IR 1.23.4.

Appendix A3-1 shows the following for Liquefied Natural Gas (LNG) Plant Operations for FEI:

- Actual 2013 - $4,331,000
- Actual 2014 - $4,698,000
- Actual 2015 - $4,967,000
- Actual 2016 - $6,110,000
- Actual 2017 - $7,716,000

Appendix A3-1 also shows the following for LNG Plant Maintenance for FEI:

- Actual 2013 - $297,000
- Actual 2014 - $683,000
- Actual 2015 - $1,223,000
- Actual 2016 - $910,000
- Actual 2017 - $309,000

23.5 Please explain why LNG Plant Operations O&M has been increasing annually and why the amounts have increased substantially in 2016 and 2017.

Response:

The increase in O&M for LNG Plant Operations is related to the incremental resources required to ensure operational readiness for start up of the Tilbury Expansion combined with an increase in customer demand for LNG. More specifically, the cost increases are associated with additional labour and contractor costs required to prepare for start up and commissioning of the Tilbury Expansion. In addition, demand for LNG continues to increase leading to additional labour costs for truck loading in addition to increased power and material costs to support additional liquefaction and logistics.

23.6 Please explain why there was a significant rise in LNG Plant Maintenance from 2013 through 2015 followed by a significant decline as of 2017.

Response:

The increase in LNG plant spending is driven by ongoing corrective maintenance and inspection that was required for one of the larger compressors that supports the Tilbury peak shaving liquefaction process. FEI experienced higher maintenance costs in 2015 and 2016 related to diagnosing and repairing a compressor unit at the Tilbury LNG plant. Having completed the diagnosis and repair, FEI was able to reduce maintenance spending on this compressor in 2017 and 2018.

23.7 If the Actual 2018 amount for LNG Plant Maintenance has changed significantly compared to Actual 2017, please explain why.

Response:

The Actual 2018 amount for LNG plant maintenance was $432 thousand, representing an increase from 2017 of $123 thousand. In 2018, in addition to inflationary pressures, FEI completed a rebuild of an LNG feed pump to the vapourizers at a cost of $81 thousand resulting in an increase in overall maintenance spending compared to 2017.

On page C-15 of the Application, FortisBC states the following:

> 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.

23.8 Please explain the correlation between the Energy Solutions team size and the addition of new natural gas customers. As part of this response, please explain in detail the roles and responsibilities of the Energy Solutions team.

Response:

The primary focus of the Energy Solutions team is to grow and retain FEI's customer base by providing energy solutions that are appropriate and meaningful to BC residents. As noted in Section B1.3.3 (page B-12) of the Application, FEI has seen an increase in annual customer attachments, adding approximately 90,400 new natural gas customers between 2014 and 2018, reinforcing that the efforts of the Energy Solutions team members together with appropriate marketing and engagement efforts have proven effective.

Although the customer additions increased incrementally annually, the headcount in the Energy Solutions team has remained relatively flat over the 2014-2018 period. The year-over-year increase in customer additions is a culmination of multiple influences including increases in new housing starts, capturing a higher market share, affordability of natural gas compared to other energy sources, and FEI's investment and efforts in actively marketing and promoting the use of natural gas with various stakeholder groups. The Energy Solutions team has been able to demonstrate incremental increases in its productivity by maintaining consistent staffing levels while increasing new customer additions.

The Energy Solutions team is comprised of four main groups focussed on serving the needs of FEI's varied customer segments.

- Residential & Small Commercial customer segment team - works primarily with builders, developers, architects and engineers on new residential and small commercial construction projects advocating natural gas as a viable heating solution.
- Large Commercial customer segment team - works with existing customers from diverse commercial sectors such as hospitals, schools, universities, municipalities, retail and

office towers by providing natural gas solutions, including account management and customer service to both add and retain customers and gas load in these sectors.

- Industrial customer segment team – works with sectors such as forestry, pulp paper, mining, agriculture, manufacturing, etc. and provides natural gas solutions including customer account management and customer service to both add and retain customers and gas load in the industrial sector.
- Marketing Products & Services team – supports the marketing & engagement efforts for the three main customers segments noted above and deploys initiatives that enable FEI to promote the use of natural gas. In addition, this group is responsible for the Main Extension Test and pilot project development and implementation.

Appendix A3-1 shows the following for Energy Solutions (Account 300-12) for FEI:

- Actual 2013 - $6,443,000
- Actual 2014 - $6,480,000
- Actual 2015 - $7,695,000
- Actual 2016 - $8,204,000
- Actual 2017 - $8,179,000

23.9 Please explain in detail the reasons for the significant increase in Energy Solutions O&M in 2015 and in 2016.

Response:

The increase in O&M costs in 2015 and 2016 can be attributed to two main areas - increased investment in Connect to Gas initiatives and increased costs for Biomethane O&M.

The increased investment in Connect to Gas during this time-frame is due, in part, to an expansion in advertising related activities to respond to policies that started to restrict the adoption of natural gas. For instance, the City of Vancouver (CoV)'s Zero Emissions Building plan for new buildings would make it challenging to integrate natural gas in new construction projects. FEI ramped up its efforts to promote the affordability and versatility of natural gas by deploying various advertising campaigns targeting Vancouver and the general Lower Mainland region. Campaigns included energy literacy initiatives educating customers about the affordability and versatility of natural gas, efforts also included using "out of home" channels such as advertising in bus shelters, sky train etc. FEI also increased incentives offered to

encourage customers to switch from other energy sources like oil or propane to natural gas. Please refer to the responses to BCUC IR 1.30.2 and 30.3.1 for further discussion.

The increase in the Biomethane costs is due primarily to an increase in spending on the RNG program. The spending for the RNG program increased due to an increase in resources assigned to the program and an increase in operating costs associated with two plant locations primarily related to consulting and field material costs, as discussed in previous Annual Reviews.

FEI also notes that there is an offsetting amount associated with the O&M which is transferred to the Biomethane Variance Account (BVA) for recovery through the Biomethane Energy Recovery Charge (BERC). This is reported as a reduction to Gross O&M Expenses (refer to line 29; page 3 of Appendix A3-1 of the MRP Application) and as such it does not remain in the O&M spending in the Energy Solutions Department.

Appendix A3-1 shows the following for Application Management (Account 420-12) for FEI:

- Actual 2013 - $13,728,000
- Actual 2014 - $13,850,000
- Actual 2015 - $14,594,000
- Actual 2016 - $15,590,000
- Actual 2017 - $12,717,000

23.10 Please explain why Application Management O&M decreased significantly in 2017.

Response:

Included in Application Management (Account 420-12) are costs for software licenses and support, which includes internal and external labour.

Factors contributing to the fluctuation in O&M costs observed from 2013 to 2017 include the impacts from the annual prioritization of O&M and capital activities and the timing of expenditures for software licenses and support. Resources from different cost areas in Information Systems (IS) participate in capital projects which cause IS's O&M costs to fluctuate from year to year. The balance between operating and capital activities for IS resources is managed across the total IS funding (capital, O&M) available. For software licenses and

support expenditures, the level of expenditures yearly will vary depending on the license and support agreements and their terms and conditions.

In 2017, an increase in charge-out of internal labour to project work (i.e., capital projects) and lower expenditures for software licences and support caused O&M expenditures in 2017 to be lower than 2016.

2018 O&M spending was somewhat higher than in 2017 primarily due to the fluctuation in allocations to capital for resources as described above.

23.10.1 If the Actual 2018 amount for Application Management O&M has changed significantly compared to Actual 2017, please explain why.

Response:

Please refer to the response to BCUC IR 1.23.10.

23.11 Please explain the significant increase in 2016 and 2017 Environment Health & Safety O&M.

Response:

Environment, Health & Safety increased by approximately $510 thousand in 2016 and a further $548 thousand in 2017 as provided in the O&M activity view in Appendix A3-1.

- 2016 O&M increased due to the launch of the Target Zero safety program. The costs and benefits of Target Zero were discussed in FEI's Annual Review for 2017 Rates in response to MoveUP IRs 1.8.1 and 1.8.3 (provided in Attachment 23.11); and
- 2017 O&M increased due to the formalization of the Corporate Sustainability program across the organization. The Corporate Sustainability program integrates and manages reporting on sustainability initiatives across our four sustainability pillars - Customer, Employees, Partner & Communities, and Environment.

In total, eight additional positions were created with six being in Occupational Health and Safety and two being in Corporate Sustainability in support of these two management programs.

Appendix A3-2 shows the following for Electric Plant O&M (Account 544) for FBC:

- Actual 2013 - $455,000
- Actual 2014 - $989,000
- Actual 2015 - $965,000
- Actual 2016 - $1,575,000
- Actual 2017 - $1,333,000

23.12 Please explain in detail the significant increases in Electric Plant O&M in Actual 2014 and in Actual 2016.

Response:

The increase in the Electric Plant O&M (Account 544) expense between 2013 and 2014 was influenced by the IBEW labour disruption in 2013, which lasted for a significant portion of the year. Operations returned to normal in 2014 which when compared to 2013 contributed to the significant increase observed in Account 544 O&M costs.

The increase between 2015 and 2016 was primarily due to a major unit inspection and runner weld at Lower Bonnington which was discussed on page 41 of FBC's Annual Review for 2017 Rates. A major unit inspection is undertaken after a generator has been running for 80,000 hours, which is the equivalent of about 10 years.

Appendix A3-2 shows the following for Information Services (Account 920.6) for FBC:

- Actual 2013 - $832,000
- Actual 2014 - $1,486,000
- Actual 2015 - $1,591,000
- Actual 2016 - $1,216,000

- Actual 2017 - $1,377,000

Appendix A3-2 shows the following for Information Services (Account 921.6) for FBC:

- Actual 2013 - $613,000
- Actual 2014 - $1,199,000
- Actual 2015 - $1,398,000
- Actual 2016 - $1,527,000
- Actual 2017 - $1,441,000

23.13 Please explain the different types of Information Services (IS) costs contained in Account 920.6 and Account 921.6.

Response:

The costs contained in accounts 920.6 (labour) and 921.6 (expenses) include all Information Services O&M costs except for consulting and contractor related costs which reside in Special Services account 567.

The IS costs in account 921.6 include licensing, maintenance, training, travel and other expenses associated with operating and maintaining all applications, infrastructure, wide area network (WAN), and telephony.

The significant increase in IS O&M for years 2014 through 2018 compared to 2013 is primarily attributed to two factors: the implementation of the AMI project and the decision by the BCUC to no longer allow FortisBC to capitalize a portion of the annual software support costs. The O&M related costs for AMI include additional staff required to meet the AMI system requirements as well as software licensing and support costs. The table below shows IS costs for accounts 920.6 and 921.6 with AMI costs broken out.

920.6 Information Services-Labour					
In $000's	**2013**	**2014**	**2015**	**2016**	**2017**
Total AMI Labour		205	472	398	759
Non AMI Labour	832	1,281	1,119	818	618
Total	**832**	**1,486**	**1,591**	**1,216**	**1,377**
921.6 Information Services-Expenses					
AMI Employee Expenses		-	4	-	1
AMI Telecom		7	142	251	1
AMI Software		-	528	484	414
AMI Hardware		-	-	4	-
Total AMI		7	673	740	416
Non AMI	613	1,192	725	787	1,025
Total	**613**	**1,199**	**1,398**	**1,527**	**1,441**

23.14 Please explain in detail the significant increase in IS O&M for years 2014 through 2018 compared to 2013.

Response:

Please refer to the response to BCUC IR 1.23.13.

Appendix A3-2 shows the following for Special Services (Account 567) for FBC:

- Actual 2013 - $838,000
- Actual 2014 - $1,914,000
- Actual 2015 - $2,449,000
- Actual 2016 - $2,887,000
- Actual 2017 - $3,090,000

23.15 Please provide a breakdown and description of the types of costs included in Special Services.

Response:

The Special Services account includes the fees and expenses of consultants and contractors and other costs not coded elsewhere. These costs were incurred by various departments throughout the Companies that provide administrative and general services. In particular, the type of costs in this account include intercompany cross charges from other Fortis utilities, Fortis Inc. management fees, contractor costs and various consulting costs, transfer pricing and other recoveries and other miscellaneous costs. It also includes an allocated amount for the capitalized overhead.

Below is a breakdown of the Special Services account from 2013 to 2017 Actual.

Particulars	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual
Intercompany cross charges	4	95	841	1,280	2,198
Fortis Inc management fees	1,669	1,940	1,530	2,051	1,687
Consulting/contractor costs [1]	1,369	1,468	1,622	2,031	1,892
Recoveries	(724)	(489)	(532)	(411)	(435)
Others [2]	153	357	803	(9)	17
Total	**2,472**	**3,372**	**4,265**	**4,943**	**5,359**
Capitalized Overhead	(1,633)	(1,458)	(1,816)	(2,056)	(2,269)
Total Special Services	**839**	**1,914**	**2,449**	**2,887**	**3,090**

[1] include legal, audit, debt rating fees, various consulting and contractor costs

[2] include provisions for PST audit in 2014 and GST audit in 2015

As per the table above, the increase in 2014 over 2013 can be explained by higher Fortis Inc. fees, provision for PST audit, lower recoveries in 2014 compared to recoveries received in 2013 from the audit of Residential Energy Credits, and lower capitalized overhead allocated to departments.

The increase in 2015 from 2014 was primarily due to increased intercompany cross charges from FEI and FHI across all general and administrative departments and the provision for GST audit. The increase was partially offset by lower Fortis Inc. management fees and higher capitalized overhead allocated to departments. In 2013 and 2014, intercompany cross charges were reported under account 920 Salaries.

The increase in 2016 from 2015 was primarily due to increased intercompany charges from FEI and FHI across all general and administrative departments and higher contractor costs to backfill employees while the Information Services employees worked on projects. Contractor costs fluctuate based on project work performed by internal employees, as contractors are used to backfill internal employees assigned to projects. This was partially offset by the provision for GST audit booked in 2015.

The slight increase in 2017 over 2016 was mainly due to increased intercompany cross charges partially offset by lower Fortis Inc. management fees.

23.16 Please explain in detail the cause(s) of the significant annual increases in Special Services O&M.

Response:

Please refer to the response to BCUC IR 1.23.15.

23.17 In consideration of the historical annual O&M provided in Appendix A3-1 and A3-2, please estimate the percentage of these expenses for each of FEI and FBC which are reasonably impacted by changes in average customers.

Response:

Please refer to the response to BCUC IR 1.17.7 which discusses why the proposed Index-Based formulaic approach is reasonable and appropriate for determining allowed O&M funding for the proposed MRPs.

23.17.1 As part of the above response, please specifically identify the O&M expenses which are likely impacted by changes in average customers and which are not likely impacted by changes in average customers and provide a rationale for each classification.

Response:

Please refer to the response to BCUC IR 1.17.7 which discusses why the proposed Index-Based formulaic approach is reasonable and appropriate for determining allowed O&M funding for the proposed MRPs.

24.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN
Exhibit B-1, Section C2.4, pp. C-17 – C42
FEI O&M Base

FortisBC provides the following table on page C-19 of the Application:

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

Footnote 121 on page C-19 of the Application states: "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)."

24.1 Please confirm, or explain otherwise, that the items included as part of the "Adjusted 2018 Base O&M" amount of $239.915 million in Table C2-1 (i.e. 2018 actual Base O&M, temporary savings, and Corporate/Shared Services Studies Impact) are intended to reflect 2018 amounts.

Response:

FEI has reviewed Table C2-1 to check that all of the figures have been properly inflated to 2019 dollars, and provides below a revised Table C2-1 incorporating all of the corrections and which will be included in an Errata to be filed in the near future. The difference is a decrease in 2019 Base O&M of $0.535 million. Each of the items is discussed separately below.

Revised Table C2-1: FEI 2019 Base O&M ($millions)

2018 actual Base O&M	$	238.693
Add temporary savings		1.677
Shared Services Studies Impact		(0.338)
Deduct 2018 actual FHI Management Fee		(12.383)
Adjusted 2018 Base O&M	$	227.649
2019 Inflator		1.02198
2019 Base O&M before adjustments	$	232.653
Adjustments:		
Exogenous Factors:		
2019 Z factor (EHT net of MSP)		0.972
Deferrals:		
FAES overhead		0.786
BCUC levies		(2.839)
NGIF funding		(0.409)
Flow Through treatment:		
Integrity Digs		(2.600)
LNG Plant O&M		5.101
2019 Normalized Forecast FHI Management Fee		11.682
2019 Reclass of FHI corporate services charged only to FEI		0.387
Total adjustments		13.081
New funding for MRP term	$	10.416
2019 Base O&M	$	256.150

Add temporary savings:

This amount is correctly stated in 2018 dollars.

Corporate/Shared Services Studies Impact:

The ($0.455) million adjustment for Corporate/Shared Services Studies was comprised of two amounts – ($0.338) million for Shared Services and ($0.117) million for Corporate Services. These two items are now separated in the table above due to their different treatments; the Shared Services Study amount remains unchanged as it is based on 2018 actual expenditures as described in Appendix D-4, FEI and FBC Shared Service Study.

For the Corporate Services study impact, the adjustment requires revision as it was not intended to only reflect the 2018 impact from the Corporate Services study impact, but also to take into account the forecasted effect of the study in 2019 Base O&M for the term of the MRP. The revisions shown above (lines titled Deduct 2018 actual Management Fee, 2019 Normalized Forecast FHI Management Fee and 2019 Reclass of FHI corporate services charged only to FEI) are discussed in the response to BCUC IR 1.146.1.

2019 Z Factors:

Correctly stated in 2019 dollars.

FAES Overhead:

Correctly stated in 2019 dollars.

BCUC Levies:

The ($2.778) million has been changed to ($2.839) million to include the 2019 inflator adjustment.

NGIF Funding:

The $0.400 million has been changed to $0.409 million to include the 2019 inflator adjustment.

Integrity Digs:

Correctly stated in 2019 dollars.

LNG Plant O&M

Correctly stated in 2019 dollars.

24.2 Please confirm, or explain otherwise, that the items included under the "Adjustments" section of Table C2-1 (i.e. Exogenous Factors, Deferrals, and Flow Through treatment) are intended to reflect 2019 amounts.

Response:

Confirmed.

24.3 Given the statement in Footnote 121 that the corporate/shared services impact is comprised of the 2019 amounts, please clarify if the adjustment should instead reflect the Actual 2018 amount, or, alternatively, if the adjustment for the 2019 amount should instead be included as part of the "Adjustments" sections of Table C2-1. Specifically, please clarify if the 2019 inflator has been incorrectly applied to the corporate/shared services studies impact.

Response:

Please refer to the responses to BCUC IRs 1.24.1 and 1.146.1.

On page C-22 of the Application, FEI states that 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.

24.4 Please explain why the $2.778 million, which represents the 2018 BCUC levies amount, was not included as an adjustment to the "Adjusted 2018 Base O&M" prior to applying the 2019 inflator adjustment to 2019 Base O&M (i.e. similar to how the temporary savings adjustment was treated).

Response:

Please refer to the response to BCUC IR 1.24.1.

24.4.1 If the adjustment for the BCUC levies requires correction, please clarify if the same correction should be applied to the Natural Gas Innovation Fund (NGIF) adjustment and the Integrity Digs adjustment.

Response:

Please refer to the response to BCUC IR 1.24.1.

24.5 Please provide a revised Table C2-1 if necessary.

Response:

Please refer to the response to BCUC IR 1.24.1.

25.0 Reference: FEI BASE O&M

Exhibit B-1, Section C2.4, pp. C-17 – C-42, Table C2-1; FEI PBR Application proceeding, Exhibit B-1, p. 150

Temporary Savings

FEI states the following on page C-19 of the Application:

> 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.

25.1 Please explain why, given Olameter's issues meeting its obligations in the last couple of years, FEI expects that Olameter will be able to meet its obligations under the contract in the future.

Response:

While Olameter has faced challenges meeting some contract service levels in the recent past, these challenges did not result in failure to meet overall SQI targets with respect to Meter Reading Accuracy and Billing Index. This was because FEI was able to work with Olameter to identify the contributing factors and provide support and insight to address the challenge(s) in a timely manner. More specifically, FEI and Olameter meet when issues arise, as well as meet on a regular monthly basis to review service level metrics, discuss and address safety concerns, staffing levels and emerging issues.

These regular meetings bring focus to the need to meet service levels and allow FEI to work closely with Olameter to address concerns in a timely fashion, meet their obligations under the contract and ultimately meet the service quality commitments to our customers.

25.2 Please explain if Olameter paid a performance penalty and/or was not able to complete all of the readings set out in the contract, resulting in reduced payments, in any of the other years of the Current PBR Plan term. If yes, please indicate which years and the amounts paid by Olameter.

Response:

In the Current PBR Plan term, Olameter paid a performance penalty in 2017 ($70 thousand) and in 2018 ($80 thousand). These penalties were largely related to the timing of the meter reads. That is, although readings may have occurred, they did not occur in accordance with the timing specified in the contract.

On page 150 of the PBR Application, FEI stated the following:

> Meter reading services are provided through a third party contract…Effective January 1, 2013 the new provider, Olameter, began reading all FEU gas meters throughout the Province…
>
> …The per meter transactional cost of the services is based on a turnkey agreement that includes the technical platform and hardware required to perform the services. This ensure that the per meter transactional pricing is fixed over the first three years of the agreement. If the Company chooses to extend the agreement for an additional two years, price increases will be limited to adjustments for CPI only…
>
> …These changes should increase customer satisfaction by reducing the number of complaints…although there will still be some situations where a meter cannot be read due to access issues, such as weather conditions.

25.3 Please confirm, or explain otherwise, that the agreement with Olameter was extended for an additional two years, as contemplated in the above preamble, and that the price increase was limited to adjustments for consumer price index (CPI) only.

Response:

The term of the original agreement between FEI and Olameter and FEI was from January 1, 2013 to December 31, 2015. The agreement included options to renew for the provision of meter reading services in 2016 and 2017.

FEI and Olameter entered into an amending agreement prior to the first renewal which revised the end of the term of the agreement to December 31, 2019. The amending agreement included pricing that was limited to one-half of the CPI, and also addressed several other changes, including performance metrics related to an advanced metering strategy.

Under the Amending Agreement, the term may be extended for one additional year (January 1 to December 31, 2020) with a price increase limited to adjustments for CPI only. FEI will be providing notice to Olameter of its intent to extend the contract on these terms prior to June 30, 2019, but it has not done so to date.

25.3.1 If the agreement with Olameter was extended, were any changes beyond the CPI-based price increase made to the agreement? If yes, please describe each change, the reason for the change, and the impact of the change to FEI.

Response:

Please refer to the response to BCUC IR 1.25.3.

25.4 Please explain if the agreement with Olameter has been renewed or extended beyond the additional two years described in the above preamble.

Response:

Please refer to the response to BCUC IR 1.25.3. Any decision to enter into renewal negotiations to extend the contract beyond December 2020 will be made by evaluating FEI's operational needs at the time.

25.4.1 If yes, please explain when the agreement was renewed/extended and for how many years the current agreement is in place.

Response:

Please refer to the responses to BCUC IRs 1.25.3 and 1.25.4.

25.4.2 If no, please explain what has transpired between FEI and Olameter since the conclusion of the five years (i.e. three years plus the two-year extension) described in the above preamble.

Response:

Please refer to the responses to BCUC IRs 1.25.3 and 1.25.4.

25.5 Please explain why, given the contractual issues FEI has experienced with Olameter, FEI has continued to contract with Olameter for meter reading services.

Response:

Please refer to the response to BCUC IR 1.25.1. On balance, throughout the term of the Agreement(s) to date, Olameter has delivered meter reading services that support FEI's delivery of high service quality standards to our customers and FEI has been able to work with Olameter to address challenges as they arise. Further, changing meter reading service providers is a lengthy process that requires sourcing, selecting and integrating a new vendor, which also means new employees, new systems and potentially new tools. A new vendor would also introduce the risk of additional costs without certainty that the new vendor would perform better. As such, FEI believes that continuing its relationship with Olameter is appropriate at this time.

25.6 Based on FEI's statement in the PBR Application, as provided in the above preamble, that "there will be some situations where a meter cannot be read due

to access issues, such as weather conditions", please further explain why it is not reasonable to expect that some amount of "savings" will continue to be experienced by FEI during the proposed MRP term.

Response:

The meter reading costs embedded in the Base O&M take into account the reduced costs associated with meters that are not read due to access issues. This is because the contract accounts for a certain level of meters that may not be read each month due to the operational realities that include weather conditions.

The impact of extreme events, such as prolonged and extreme winter conditions and wildfires, are not reflected.

On page C-20 of the Application, FortisBC states the following regarding FEI's bad debt expenses:

> 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 be considered to be representative of future bad debt expense.

25.7 Please provide the formula and actual bad debt expense for years' 2014 through 2018 and the formula and projected bad debt expense for 2019.

Response:

Bad debt expense is embedded within the overall O&M formula in the Current PBR Plan, and therefore there is no specific formula for bad debt expense itself. However, FEI is able to provide the actual bad debt expense for the years 2014-2018 and projected bad debt expense for 2019 in the table below.

	2014	2015	2016	2017	2018	2019P
Bad Debt Expense	3,253,196	1,649,848	1,157,216	1,874,084	891,464	1,800,000

25.8 Please explain why, when considering all areas of FEI's O&M expenses, FEI has not been able to identify any cost increases in 2018 which it would consider "temporary" and would therefore serve to offset the temporary savings.

Response:

FEI's 2018 net overall achieved O&M savings of approximately $4.9 million (actual expenditures compared to allowed) is comprised of a number of favourable variances (savings) and unfavourable variances (costs), some of which offset one another. However, the final overall 2018 results indicate a net overall savings (i.e., net of the favourable and unfavourable variances) of which a portion have been classified as temporary.

For the purpose of establishing a reasonable and appropriate O&M Base for the proposed MRP, FEI focused on reviewing the net overall O&M savings to identify the more material items that are considered temporary and non-sustainable. This is to ensure that the appropriate level of O&M funding is included in the 2019 O&M Base for the term of the MRP. From FEI's perspective, temporary savings are generally defined as savings that are not expected to be repeated and therefore require funding in the following year(s).

With the above context, FEI reviewed the 2018 overall net O&M savings achieved to identify the material portion that is considered temporary and non-sustainable. For the reasons discussed on pages C-19 and C-20 of the Application, meter reading and bad debts savings were determined to be temporary in 2018 as past experience supports that higher meter reading and bad debts expense will be incurred in the future. As a result, the addback of $1.677 million for 2018 temporary meter reading and bad debts savings to achieve the 2019 Base O&M is required.

26.0 Reference: FEI BASE O&M

Exhibit B-1, Section C2.4, pp. C-17 – C-42

Adjustments to Base O&M

On page C-21 of the Application, FEI proposes to set the 2019 Base O&M to include an amount for the FortisBC Alternative Energy Services Inc. (FAES) overhead recoveries and proposes to increase the 2019 Base O&M by $0.786 million, which equals the difference between the recovery for services required and the amounts approved in rates.

26.1 Please provide a more detailed breakdown and description of the $140,000 projected FAES overhead recoveries for 2019.

Response:

The $140 thousand projected FAES overhead recoveries for 2019 is comprised of the following three amounts:

- $69 thousand for facilities costs at the 1111 West Georgia office. These costs are made up of lease costs, office cleaning and maintenance, and other administrative costs.
- $69 thousand for information technology costs. These costs include all hardware and software costs for FAES employees, as well as IT support and client service costs.
- $2 thousand for telecommunications costs.

26.2 Please further explain why FEI expects that the FAES overhead recoveries will remain at approximately $140,000 (plus inflation) for the proposed MRP term.

Response:

FEI expects that the FAES overhead recoveries will remain at approximately $140 thousand (plus indexing) for the proposed MRP term as the recoveries have been relatively stable the last few years, and there are no material changes anticipated to the FAES business or its level of reliance on FEI for supporting infrastructure during the proposed MRP term. An example of this relates to the lease costs at the 1111 West Georgia office, which are allocated based on the percentage of space used by each of the business areas. At this time, there are no indications that FAES will use more or less space within the office than they currently use; therefore, the overhead recovery amount is expected to remain similar to 2019 levels.

26.3 Please explain, and provide a numerical example of, how variances between formula and actual FAES overhead recoveries will be treated during the proposed MRP term.

Response:

The FAES overhead recoveries will be treated the same as the other components of FEI's index-based O&M. Under FEI's proposal, the delivery rates for 2020 through 2024 will be set using a credit/recovery of $140 thousand (plus annual indexing) as the base for the amounts included in O&M.

FEI will then charge FAES the actual costs incurred each year, with the variance between the actual FEI O&M recoveries and the amount embedded in delivery rates shared equally with customers.

Please also refer to the hypothetical example provided below which shows that in the situation where actual O&M recoveries are higher than amounts embedded in rates each year, FEI would share the difference equally with customers over the MRP term through the earnings sharing mechanism.

($000s)	2019B	2020	2021	2022	2023	2024	Total
Formula Inflation Factor		1.02	1.02	1.02	1.02	1.02	
Base and Formula	140.0	142.8	145.7	148.6	151.5	154.6	
Actual		145.0	155.0	165.0	175.0	185.0	
Difference		(2.2)	(9.3)	(16.4)	(23.5)	(30.4)	(81.9)
Sharing %		50%	50%	50%	50%	50%	50%
Amount to recover/(return) to customers		(1.1)	(4.7)	(8.2)	(11.7)	(15.2)	(40.9)

On page C-22 of the Application, FortisBC states that actual BCUC levies in 2018 were higher than approved.

26.4 Please confirm, or explain otherwise, that the annual variances between formula and actual BCUC levies did not impact (i.e. were not included in) the 50/50 earnings sharing calculation during the Current PBR Plan.

Response:

Confirmed.

On page C-22 of the Application, FortisBC states: "FEI's 2018 O&M includes its current $0.400 million contribution to the NGIF."

26.5 Please confirm, or explain otherwise, that the above statement means that the Actual 2018 O&M includes an amount of $0.400 million for the Natural Gas Innovation Fund (NGIF).

Response:

Confirmed.

26.5.1 As part of the above response, please confirm, or explain otherwise, that the NGIF and the resulting annual contribution were not approved as part of the FEI PBR Decision and thus did not form part of the approved Base O&M.

Response:

FEI disagrees with the premise that specific BCUC approval was required of O&M items or that FEI's O&M spending was strictly limited to the items in FEI's Base O&M. Rather, in the FEI 2014 PBR Decision, the BCUC approved a Base O&M that was then escalated by formula to provide an overall O&M funding envelope over the term of the Current PBR Plan. The premise of the Current PBR Plan is that FEI was free to work within the O&M spending envelope, and FEI has been managing its spending levels within that funding envelope to continue to deliver safe and efficient service while investing in the future health of the utility.

Although there was no spending on the initiative included in the 2013 Approved O&M that formed the base for the Current PBR Plan formula O&M, FEI did discuss this initiative as one it

was intending to pursue during the term of the Current PBR Plan. On page 161 of its 2014-2018 PBR Application, FEI identified incremental spending of $500 thousand starting in 2014 to advance natural gas end-use technologies and applications by working collaboratively with stakeholders such as the Canadian Gas Association (CGA). In response to BCUC IR 1.105.1 on FEI's 2014-2018 PBR Application, FEI explained that this represented an expansion of FEI's involvement in an initiative through the CGA called Energy Technology Innovation Canada (ETIC) that was launched in 2011. The ETIC is a predecessor to the Natural Gas Innovation Fund (NGIF).

Since FEI planned to manage its early stage investments in the ETIC and NGIF within the formula O&M envelope, FEI did not request a separate deferral account to account for these costs.

As FEI plays an increasingly important role in helping British Columbians move to a lower carbon, renewable energy future, the NGIF is a necessary part of the 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 customers.

26.5.2 Please explain if FEI sought approval of the NGIF from the BCUC prior to implementing it and if the NGIF is a deferral account

Response:

Please refer to the response to BCUC IR 1.26.5.1.

26.6 Please provide the following information regarding the NGIF:

- When the NGIF was established;
- A description of the NGIF, including its purpose;
- How the NGIF is funded (i.e. through ratepayers, shareholders, grants, etc.);
- How the amount of the annual contribution is determined; and
- How the NGIF is administered and by whom.

Response:

The Natural Gas Innovation Fund™ (NGIF) was created in 2016 by the Canadian Gas Association to support the funding of clean technology innovation in the natural gas value chain. The fund:

- Fills a technology development gap in the sector and invests in innovation enabling natural gas solutions for current and emerging challenges facing Canada's energy system.
- Is capitalized by the natural gas industry with access to pooled R&D innovation funding, leveraged intelligence, and a combined backyard across Canada to field test innovation.
- Selects and advances natural gas clean technology projects led by start-ups and organizations with the right innovation for market uptake and commercial viability.

NGIF's mission is to build a diversified portfolio of successful investments, strategic partnerships, and a trusted investment model that, combined, deliver on improved environmental and economic performance for the natural gas value chain. Their mandate is to take action and advance the most promising enterprises in cleantech innovation and support them through their projects to commercialization and market success.

The NGIF is widely supported and includes collaboration between industry, federal and provincial governments as noted in their December 20, 2018 announcement:[37]

> **The Natural Gas Innovation Fund™ Announces a Federal/Provincial Government and Industry Collaborative to Support GHG Emission Reduction**
>
> NGIF, together with Natural Resources Canada (NRCan), Emissions Reduction Alberta (ERA), Alberta Innovates (AI) and the Province of British Columbia Innovative Clean Energy ICE Fund (ICE Fund) will collaborate on this funding call under trusted partner relationships. To demonstrate their support for the engagement of producers in the fund, NRCan, ERA, AI and ICE Fund will consider co-funding successful NGIF applicants that have projects which deliver significant GHG emission reduction and are located in Canada, Alberta and British Columbia, respectively.

NGIF's members pay an annual administrative fee to be part of the fund which is based upon their size. Members also contribute funds to specific projects where they elect to be a participant. More recently, the NGIF has expanded and there are now members farther up the

[37] http://www.ngif.ca/natural-gas-innovation-fund-signs-on-seven-leading-natural-gas-producers-launches-a-cleantech-funding-call-and-leads-a-historic-federal-provincial-and-industry-co-funding-collaboration/.

value chain including producers and other upstream companies. These new members participate in NGIF in the same manner as existing members.

NGIF holds regular funding calls seeking applicants to submit requests for innovation funding. Through an NGIF structured process, applicants' funding requests are reviewed and successful applicants are determined based upon utility needs and the ability to fund the opportunity. Each individual utility then chooses whether to fund an applicant and the funding costs are split amongst the participating utilities. There is no obligation on individual utilities to fund projects. FortisBC understand that utility funding is via each utilities O&M funding. Participating natural gas distribution utilities include ATCO, Enbridge, SaskEnergy and Pacific Northern Gas Ltd.

NGIF today currently has approved funding for $8.9 million in cleantech projects for natural gas. Annual contribution is determined by the level of funding requests, which are evaluated by a stage-gated investment process.

NGIF is administered by a small team led by the fund's Managing Director.

26.7 Please explain which O&M activity account the $0.400 million is recorded in.

Response:

The $0.400 million is recorded in O&M Accounts 310-12 Energy Solutions, and 310-11 Energy Solutions & External Relations Supervision.

26.8 Please provide a description of the costs incurred by FEI as part of the $0.400 million "contribution" in 2018.

Response:

The $0.400 million includes grant funding to participants in the NGIF for the successful completion of project milestones, as well as contributions towards the regular operating expenditures of the NGIF. With respect to the grant-funding component, NGIF and the participating utilities determine which proponents will be awarded funding and how much funding is received by each proponent. NGIF and the participating utilities then agree on how

much each participating utility will fund. NGIF requests these amounts from the utilities and then disburses the funding to the proponent based upon an agreed upon schedule and milestone framework.

26.9 Please provide a detailed comparison of the NGIF to the proposed Innovation Fund.

Response:

The NGIF and the Clean Growth Innovation Fund have similar goals in that they both are focused on clean technology innovation.

The proposed Clean Growth Innovation Fund differs from NGIF in several ways. The NGIF is national and therefore looks at projects that may be relevant to other jurisdictions, but not in BC. The NGIF also looks at the midstream and upstream natural gas value chain, which is not in scope for distribution utilities.

The Clean Growth Innovation Fund has several additional features as compared to NGIF. Specifically, the Clean Growth Innovation Fund:

- invests in clean technology related to the electric value chain in addition to natural gas;
- invests in commercial innovations in addition to pre-commercial innovation; and
- invests in gas innovations that address BC provincial priorities and interests.

On page C-22 of the Application, FEI states: "If FEI's Innovation Funding proposal is approved, then the amount currently provided by O&M will be removed."

26.10 Under a scenario where FEI's Innovation Funding proposal is not approved, please explain if FEI would propose to continue utilizing the NGIF. If yes, please explain in detail how the NGIF would operate during the proposed MRP term.

Response:

If the proposed Clean Growth Innovation Fund is not approved, FortisBC plans to continue funding the NGIF at current levels under the index-based O&M mechanism. As indicated on

page C-22 of the Application "If FEI's Innovation Funding proposal is approved, then the amount currently provided by O&M will be removed." Conversely, if the proposal is not approved, then the O&M amount will be re-instated. As noted in Section C6.4.3.4 of the Application, predictable funding is a key design feature of the Clean Growth Innovation Fund which enables sustained innovation.

26.10.1 As part of the above response, please explain if FEI intends to continue the use of the NGIF if the Innovation Fund is approved and, if so, how each fund would be utilized.

Response:

FortisBC intends to continue funding relevant NGIF projects if the Clean Growth Innovation Fund is approved. Doing so is consistent with the guiding principles of the Clean Growth Innovation Fund including leveraging partnerships and using a portfolio approach in order to diversify risks. If approved, funding for the NGIF would flow from the Clean Growth Innovation Fund rather than from O&M.

27.0 Reference: FEI BASE O&M

Exhibit B-1, Section C2.4, pp. C-22–C-23, C-111

Adjustments – Integrity Digs

On pages C-22 and C-111 of the Application, FEI states that it proposes to treat the costs of integrity digs outside of the index-based O&M and to capture variances in FEI's integrity digs in the Flow-through deferral account.

FEI further states the following on page C-22 of the Application:

> 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, timing and volume of integrity digs that may be experience over the term of the Proposed MRPs.

27.1 Please provide the amount included in the Current PBR Plan's Base O&M for integrity digs. As part of this response, please provide the amount approved as part of the FEI PBR Decision and the amount approved to be added to the Current PBR Plan's Base O&M for the inclusion of FEVI and FEW in the FEI PBR Plan (if any).

Response:

In the FEI 2014 PBR Decision, the BCUC approved a 2013 Base O&M that was then escalated by formula to provide an overall O&M funding envelope over the term of the Current PBR Plan. An additional amount was added in 2014 for FEVI and FEW. There was no specific amount for integrity digs approved for any of the utilities as part of the O&M Base. As such, FEI cannot provide the requested information, but can provide the 2013 Actual expenditures for FEI which were $1.4 million. Neither FEVI nor FEW had any expenditures in 2014.

27.2 Please confirm, or explain otherwise, that the annual variances between formula and actual integrity dig costs would have impacted the amount of O&M savings and the amount of earnings sharing.

Response:

Confirmed.

27.3 Please explain the specific issues that have arisen during the Current PBR Plan term that would not allow the current formulaic approach to be appropriate under the proposed MRP. For each issue identified, please explain how the issue has impacted ratepayers and/or FEI shareholders.

Response:

Specific issues that have arisen during the Current PBR Plan term with respect to Integrity Digs that have resulted in FEI's determination of considerable uncertainty related to scope, cost, timing and volume of expected digs during the proposed MRP term are as follows:

- FEI's requirement to align with industry standard practice through adoption of new or improved in-line inspection technologies:
  - FEI's adoption of circumferential magnetic flux leakage (CMFL) tools starting in late 2013 resulted in higher numbers of integrity digs over the Current PBR Plan term.
- FEI's obligation to align its practices to current standards and regulations:
  - FEI's adoption of strain-based criteria for dents starting in 2013 resulted in higher numbers of integrity digs over the Current PBR Plan term.
- FEI's experience with the cost of integrity digs varying significantly:
  - As indicated in FEI's response to BCUC IR 1.8.1.2 in the FEI IGU CPCN Application proceeding (provided as Attachment 27.3), FEI recorded several digs exceeding $150,000 during the 2015 to 2018 time period.
- FEI's challenges in balancing dig timing relative to other integrity activities:
  - ILI-driven digs are considered by FEI as having limited schedule flexibility. To accommodate scope pressures indicated above for ILI-driven digs (i.e., CMFL tool adoption and strain-based dent criteria), FEI has subsequently modified its scheduling of digs identified on non-piggable transmission pipelines.
- FEI's challenges in estimating the volume of integrity digs:
  - When running an in-line inspection tool technology in a pipeline for the first time (e.g., CMFL tools during the Current PBR Plan term), predictions of the potential number of digs required are highly uncertain.

These issues will continue to impact FEI's operations and integrity management, and there are incremental activities anticipated over the MRP term. FEI is proposing to provide in-line inspection capability to 11 laterals as part of the Inland Gas Upgrade Project, and expects that it will propose to provide crack-detection in-line inspection capabilities for a number of larger diameter mainline pipelines as part of the Transmission Integrity Management Capabilities Project (TIMC). As part of the TIMC Project development, FEI will be piloting the use of crack-detection in-line inspection tools in its system as early as 2019. These activities will result in pipelines being in-line inspected for the first time, as well as pipelines being inspected with a new ILI technology for the first time. As discussed in Section C2.4.2.2.3 of the Application, 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.

27.4 Please explain why it would not be appropriate to continue including integrity digs in formula O&M and, if necessary, apply for Z-factor treatment if actual O&M amounts significantly vary from formula amounts. Please discuss the pros and cons of this approach compared to FEI's proposed approach.

Response:

As described in the Application, FEI is proposing to treat the costs of integrity digs outside of index-based O&M, similar to its other non-controllable O&M costs, 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 is similar to a Z-factor treatment approach in that customers will only pay for the actual costs incurred. However, the proposed flow through treatment is more appropriate, as it provides greater certainty on available funding for FEI to undertake required activities during the term of the proposed MRP, without increased regulatory process or potential delays caused by the having to apply and obtain approval for Z-factor treatment possibly multiple times over the proposed MRP term. Finally, integrity digs are a part of the regular business and, absent any regulatory changes, do not fit within any of the criteria for Z-factor treatment. For these reasons, FEI has proposed to forecast these costs annually, consistent with other non-controllable costs.

On page C-23 of the Application, FEI states the following:

> 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 kilometres of pipelines undergoing in-line inspection (ILI) increase and as the types of inspection tools and tool runs rise.

27.5 Please provide and discuss whether there is a "volume of integrity digs" to "kilometres of pipelines inspected" ratio which FEI considers appropriate to apply to estimating the volume of required integrity digs in any given year. If the ratio is dependent on certain factors (e.g. performing ILI in a pipeline for the first time), please specify.

Response:

Generally speaking, as the number and length of pipelines subject to in-line inspection increases, the number of integrity digs increases as integrity digs are a component of the in-line inspection process. However, a ratio of the number of integrity digs to kilometres of pipelines inspected cannot be used to estimate the volume of required integrity digs in any given year. This is because there are many factors besides the length of pipelines inspected that influence FEI's integrity dig requirements in any given year. For example, integrity digs may be performed as a result of analysis that occurs during the interim years between inspections and, as such, they may be scheduled in any of the years between successive tool runs.

As an illustration, the following table demonstrates the degree of fluctuation that exists in the ratio of the number of integrity digs to kilometres of pipelines inspected, even if offset by one or two years. Beyond expressing this in general terms, the correlation is too weak to provide a basis to estimate the volume of required integrity digs in any given year. This correlation is discussed in further detail in the response to BCUC IR 1.32.8.

Table 1: Length of Pipe In-Line Inspected, Number of Integrity Digs, and "Number of Digs/Inspected Length" Ratios from 2011 to 2018

Year	Length of Pipe Inspected (km)	Number of Integrity Digs+	Ratio (year of inspection)	Ratio (Year following inspection)	Ratio (2 years following inspection)
2011	142	45	0.32	Not applicable	Not applicable
2012	568	30	0.05	0.21	Not applicable
2013	708	46*	0.06	0.08	0.32
2014	1202	58	0.05	0.08	0.1
2015	396	64*	0.16	0.05	0.09
2016	478	74*	0.15	0.19	0.06

Year	Length of Pipe Inspected (km)	Number of Integrity Digs+	Ratio (year of inspection)	Ratio (Year following inspection)	Ratio (2 years following inspection)
2017	704	90	0.13	0.19	0.23
2018	588	85*	0.14	0.12	0.18

+ Only ILI driven integrity digs.

** Note: Variance in dig numbers from past reporting has resulted from ongoing efforts in collecting and verifying historical dig data. Please refer to the response to BCUC IR 1.32.6 for complete year-to-year dig numbers.*

28.0 Reference: FEI BASE O&M

Exhibit B-1, Section C2.4, pp. C-24 – C-29; FEI 2019 Annual Review proceeding, Exhibit B-1, p 53; Exhibit B-3, BCUC IR 17.1

Adjustments – LNG O&M Costs

On page C-24 of the Application, FortisBC states that during the Current PBR Plan term, FEI recovered the total liquefied natural gas (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.

28.1 Please provide the following information for the first category of costs described in the above preamble:

- Breakdown and description of the annual formula O&M costs for each of the year's 2014 through 2019 separated between variable and fixed costs;
- Breakdown and description of the annual actual O&M costs for each of the year's 2014 through 2018 and projected 2019 separated between variable and fixed costs. As part of this response, please identify which O&M activity account the annual costs were recorded in.

Response:

Under the Current PBR Plan, FEI's formula O&M spending is determined at the aggregate level. FEI does not have disaggregated O&M spending envelopes or formula calculations. Therefore, FEI's formula O&M costs cannot be further disaggregated.

However, FEI is able to provide a breakdown of the actual O&M costs for 2014 to 2018 and projected for 2019. These costs are for peaking storage to serve core utility customers.

Actual Formula	2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual		2019 Projected	
In $000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	4,081		3,948		3,822		3,456		3,969		4,329	
Employee Expenses	71		90		71		106		287		267	
Vehicles	41		45		37		42		56		49	
Materials	427		481		586		562		562		385	
Contractors	384		965		928		1,147		738		715	
Fees & Admin	349		33		80		123		108		90	
Facilities	110		94		115		159		146		146	
Recoveries	(25)		(42)		(40)		(27)		(9)		(50)	
Electricity		778		587		631		598		435		706
Total	**5,439**	**778**	**5,613**	**587**	**5,601**	**631**	**5,569**	**598**	**5,857**	**435**	**5,931**	**706**

28.2 Please provide the following information for the second category of costs described in the above preamble:

- Breakdown and description of the annual forecast O&M costs for each of the year's 2014 through 2019 separated between variable and fixed costs; and
- Breakdown and description of the annual actual O&M costs for each of the year's 2014 through 2018 and projected 2019 separated between variable and fixed costs. As part of this response, please identify which O&M activity account the annual costs were recorded in.

Response:

The table below provides forecasted flow-through O&M for RS 46 service, which is broken down as fixed and variable costs for the period of 2014 to 2019:

Flow-through	2014 Forecast		2015 Forecast		2016 Forecast		2017 Forecast		2018 Forecast		2019 Forecast	
In 000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	77	54	224	80	176	105	1,352	176	2,414	182	2,670	283
Employee Expenses												
Vehicles												
Materials	17		49		41		156		91		130	
Contractors	25		73		60		345		732		773	
Office												
Computer												
Fees & Admin							120		160		160	
Facilities	15		42		40		166		135		144	
Electricity		188		467		448		2,660		2,936		3,272
Total	**134**	**242**	**388**	**547**	**317**	**553**	**2,139**	**2,836**	**3,532**	**3,118**	**3,877**	**3,555**

The table below provides actual flow through O&M for RS 46 service, which is broken down as fixed and variable costs from 2014 to 2018, including the 2019 projection. These costs were recorded in O&M activity accounts 130-11 LNG Plant Operations and 130-21 LNG Plant Maintenance.

Flow-through	2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual		2019 Projected	
In 000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	194	67	136	98	361	112	1,473	160	2,717	354	2,908	406
Employee Expenses	0				19		45		36			
Vehicles	0		0		1		0		1			
Materials	32		46		59		52		202	310	130	411
Contractors	12		9		291		644		603		1,891	
Fees & Admin					1		22		25		160	
Facilities	16				30		142		28			
Electricity		228		334		565		404		2,271		3,981
Total	**255**	**295**	**193**	**432**	**762**	**676**	**2,379**	**564**	**3,612**	**2,935**	**5,089**	**4,798**

On page C-25 of the Application, FortisBC states the following:

> 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…

On page C-26 of the Application, FortisBC states: "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."

28.3 In consideration of the fact that the Tilbury Expansion facility will only have been fully in service by the end of 2019, please discuss the likelihood that the fixed O&M expenditures proposed to be included in Base O&M will be significantly higher or lower than expected.

Response:

While there is expected to be some variation in operational costs as FEI gains experience maintaining the equipment within the Tilbury Expansion facility, FEI has taken steps to minimize the potential for significant variances in the O&M expenditures proposed. Costs related to maintaining the facility, including such items as labour, materials, contractors and technical support, would drive the majority of potential cost variation. In order to mitigate the risk associated with these costs, FEI has completed a full review of the plant equipment to estimate the appropriate resources required to maintain the plant while applying past experience operating the LNG peak shaving facilities where possible. The methodology applied has provided the best opportunity to establish an accurate budget for the Tilbury Expansion. Finally, it is important to note that, in additional to variation in operational costs, these costs will also be subject to inflation for services and materials or changes in regulation that may occur during the term of the proposed MRP.

28.3.1 To the extent possible, please provide a forecast of the fixed and variable LNG O&M costs for each year of the proposed MRP term.

Response:

FortisBC (FEI and FBC) are proposing an Index-Based formula approach based on total O&M per customer to determine overall O&M funding for the MRP period. As a result, FortisBC has not prepared a forecast of index-based O&M over the term of the proposed MRPs or a forecast of annually forecasted items at this time. FEI will provide an annual forecast for 2020 variable LNG Production O&M at the 2020 Annual Review of Rates.

28.3.2 In the event that fixed O&M expenditures for the LNG facilities are materially different during the MRP term from that which is included in the Base O&M, please explain how FEI would propose to address the significant variances. For instance, would FEI propose to re-base fixed costs? Please explain why or why not.

Response:

As discussed in the Application, variances in controllable O&M (inflation-indexed O&M) that are included in the 2019 Base O&M will fall to earnings and be subject earnings sharing. Therefore, FEI would not propose to re-base the fixed component in 2019 Base related to LNG production if the fixed costs increased. However, if an unforeseen event caused the fixed costs of LNG production to decrease or increase materially, this may qualify for exogenous factor treatment, which would be determined in an Annual Review.

28.4 Please explain why, as a result of FEI's proposed allocation between fixed and variable costs, there are no variable costs which are proposed to be removed from Base O&M and re-classified as flow-through.

Response:

There are variable costs that are proposed to be removed from Base O&M and re-classified as flow-through. FEI has proposed that all costs that are dependent upon the production level of LNG are to be allocated as flow-through outside the Base O&M. As such, this will require a portion of the costs currently allocated to Base O&M to be re-allocated to flow-through O&M

including variable electric power costs and a portion of the variable process-related material costs.

In response to BCUC IR 17.1 in the FEI 2019 Annual Review proceeding, FEI provided the following response and tables:

Response:

The following table shows the 2017 Actual, 2018 Projected and 2019 Forecast for the Tilbury Plant.

The FTE values provided in the table reflect the amount of labour expense associated with total employee headcount charged toward Rate Schedule 46 Activities.

	2017 Headcount Actuals	2018 Headcount Projected	2019 Headcount Forecast
LNG Plant Operators	19	25	25
LNG Millwrights	0	2	2
LNG Electrical and Instrument Technicians	2	4	4
LNG Administrative Assistant	1	1	1
	22	32	32

	2017 FTE Actuals	2018 FTE Projected	2019 FTE Forecast
Tilbury LNG FTEs	9	15	21

28.5 Please revise the above headcount and full time equivalent (FTE) tables to show the actual headcount and FTEs attributable to RS 46 activities for each year of the Current PBR Plan term and the projected amounts for 2019.

Response:

For clarity, please note that the headcount forecast in the preamble includes:

- Headcount for all of Tilbury LNG, and
- FTEs for RS46 only.

Provided below are the headcount and full time equivalents tables from 2014 to 2018 Actual and 2019 Projection attributed to RS 46 activities only (LNG flow-through).

	Actual					Projected
Headcount	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
LNG Plant Operators	2	2	5	9	12	14
LNG Millwrights	0	0	0	0	2	5
LNG Electrical and Instrument Technicians	0	0	2	2	4	4
LNG Administrative Assistant	0	0	0	0	0	0
Total	**2**	**2**	**7**	**11**	**18**	**23**

	Actuals					Projected
FTEs	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Tilbury LNG	1	2	4	9	14	18

28.6 Please provide the actual annual headcount and FTEs for each year of the Current PBR Plan term attributable to the activities described on page C-24 of the Application related to "providing peaking storage to service core utility customers…recovered as part of Base O&M."

Response:

Provided below are the headcount and full time equivalents tables from 2014 to 2018 Actual and 2019 Projection attributed to LNG Base O&M.

	Actual					Projected
Base O&M Headcount	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Tilbury LNG	12	12	11	11	11	11
Mt. Hayes LNG	12	11	11	11	11	13
Supporting Staff	4	5	6	8	8	12
Total	**28**	**28**	**28**	**30**	**30**	**36**

	Actual					Projected
Base O&M FTEs	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Tilbury LNG	12	12	11	11	12	12
Mt. Hayes LNG	11	12	12	11	12	13
Supporting Staff	3	4	5	7	7	8
Total	**27**	**28**	**27**	**29**	**31**	**33**

28.7 Please separately provide the forecast headcount and FTEs for each year of the proposed MRP term attributable to formula O&M and attributable to forecast/flow-through O&M.

Response:

FortisBC (FEI and FBC) is proposing an index-based formula approach based on total O&M per customer to determine overall O&M funding for the MRP term. As a result, FortisBC has not prepared a forecast of index-based O&M over the term of the proposed MRPs or a forecast of annually forecasted items at this time. FEI will provide an annual forecast for 2020 variable LNG Production O&M at the 2020 Review of Rates.

FEI provides the following table which includes the 2019 projected headcount and FTEs for all LNG operations including supporting management and engineering staff:

	2019 Headcount Projected	**2019 FTE Projected**
Tilbury LNG	34	30
Mt. Hayes LNG	13	13
Supporting Staff	12	8
Total	**59**	**51**

On page C-28 of the Application, FortisBC provides the following table:

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

On page C-27 of the Application, FortisBC states the following:

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.

28.8 Please provide a copy of the self-assessment that FEI submitted to the BC OGC in response to the above request, as well as any subsequent correspondence between FEI and the BC OGC on this matter.

Response:

Please refer to Attachment 28.8 for a copy of the document entitled "Integrity Management Program – Facilities (IMP-F) Self-Assessment", submitted to the BC OGC on November 30, 2017, in response to Industry Bulletin 2017-11 issued June 28, 2017, entitled "New Requirements for Integrity Management Programs for Facilities":

The BC OGC conducted a formal IMP-F compliance audit for FEI's LNG facilities on October 23 and 24, 2018. The audit entailed confirmation of the scope of the compliance assurance process and systematic review of processes, records, and documents to verify compliance against 15 IMP-F components outlined in the IMP-F Compliance Assurance Protocol.

The BC OGC provided FEI with the draft IMP-F Audit Report on April 12, 2019 for review and comments. After FEI's response to the BC OGC on May 3, 2019, the final audit report for LNG processing assets was received on May 14, 2019. Please also refer to Attachment 28.8 for a copy of FEI's response dated May 3, 2019, and the final BC OGC Audit Report dated May 14, 2019.

FEI is required to submit the Corrective Action Plan (CAP) with proposed corrective actions and timelines for completion of corrective actions by June 14, 2019.

On page C-28 of the Application, FortisBC states the following:

> 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 of the positions.

28.9 Please provide a detailed explanation for why each new position is required and what function(s) the new positions will be performing, including the job titles and descriptions of each new position.

Response:

The job title of the two new positions that will be added is "LNG Millwright." The role of the millwright is to complete preventive and corrective maintenance for all the mechanical equipment at the Tilbury Facility. The two millwrights are required to ensure the annual maintenance program for the Tilbury facility is adequately resourced. The two additional millwright positions were identified as being needed after completing a detailed assessment of the equipment maintenance requirements as part of the start up of Tilbury Expansion. The assessment methodology is commonly known within industry as a "reliability centred maintenance" assessment, where each technical function within the plant is reviewed to define the appropriate preventive maintenance that is required for safe and reliable plant operations. The result is incremental maintenance requirements, which give rise to the need for additional LNG Millwrights.

The six positions added part way through the year, referenced on page C-28 of the Application as quoted in the preamble above, related to operator positions approved as part of the FEI 2018 Annual Review.

28.10 Please provide a detailed explanation for why the additional $0.295 million is required for additional contractor support for maintenance of the Tilbury LNG Facility.

Response:

The additional funding required for contractor support at the Tilbury site relates to the estimated annual cost for external service agreements that FEI needs to retain in order to maintain complex equipment that requires specialized expertise. These services were previously provided by Bechtel, the prime contractor for the Tilbury Expansion, but beginning in 2019, the responsibility for these services was transferred to FEI. Examples of such equipment that require maintenance activities using third party support include the distributed control system, electrical substation, major compressors, liquefier, process safety valve re-certification, fugitive emission monitoring and plant-wide corrosion monitoring. In addition, contractor support is also required to maintain facility-related items including the fire and gas detection system, the security system, and the LNG truck loading area.

28.11 Please explain in detail why an additional maintenance employee is required for the Mt. Hayes LNG Facility during the proposed MRP term.

Response:

As stated on page C-27 of the Application, an integrity management program is required by all oil and gas facilities within British Columbia. As part of FEI's Safety and Loss Management Program for LNG, preventive and corrective maintenance at the Mt. Hayes LNG Facility is required to ensure the safety of the plant and to comply with all legislated requirements. In addition, the planning and execution of this work must be accurately documented within the corporate maintenance management system. Currently, the Mt. Hayes Facility has seen an increase in demand for LNG, and when coupled with the new requirements mentioned above, additional support is required to complete all the mechanical maintenance work and related documentation within the corporate maintenance management system.

On page C-28 of the Application, FortisBC states: "$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 through 2018, with costs offset partially with expected cross charging of labour to capital activities."

28.12 How many operations managers and safety and compliance managers are currently utilized for the Tilbury and Mt. Hayes LNG facilities?

Response:

The Tilbury LNG facility currently has one operations manager and zero safety and compliance managers. Similarly, the Mt. Hayes LNG facility currently has one operations manager and zero safety and compliance managers.

Throughout the operating life as a peak-shaving facility, the Tilbury plant has required a single operations manager to lead the employees and manage the work at the plant. The Tilbury facility now operates at seven times the daily production capacity with a more extensive process than it did previously. The facility also provides 24 hour per day, seven day a week customer

service and maintenance activities are required on equipment of greater size and complexity. As such, the level of responsibility has now outgrown the capacity of a single operations manager and a second manager is required to support management of the plant and continued reliable and productive operational and maintenance activities. Conversely, there is no requirement for an additional operations manager at the Mt. Hayes facility at this time.

Several factors also drive the requirement for a safety and compliance manager. As described on page C-27 of the Application, the degree of regulation for LNG facilities has evolved resulting in an increased level of activity required to develop and maintain an effective safety and loss management program. Further, the production capacity of the Tilbury facility has experienced a step change in growth which has increased the scope and scale of the industrial hazards present at the site. Finally, both the Tilbury and Mt. Hayes plants have experienced increased levels of operational activities on-site requiring an increase in the number of employees and contractors that are actively working within the industrial area on a continuous basis. The combination of these factors has resulted in the requirement for a safety and compliance manager dedicated to support the development and monitoring of the related management systems and practices that must be in place to ensure all operational, maintenance and capital work is completed safely and in compliance with all regulatory requirements.

28.12.1 As part of the above response, please explain in detail why the additional managers are required.

Response:

Please refer to the response to BCUC IR 1.28.12.

28.13 Please explain why the activities related to safety and compliance cannot be performed by existing O&M resources in departments such as the Engineering Services & Project Management department.

Response:

With the Tilbury Expansion now in operation, the increase in customer demand for LNG at both the Tilbury and Mt. Hayes facilities and the evolving regulatory requirements for all LNG facilities

as referenced on page C-27 of the Application, there is a step change in business activity that now exists that was not present in previous years. Existing O&M resources within FEI are fully allocated to existing work outside of the LNG facilities and there is no indication of reduced workload for these resources within the foreseeable future.

On page 53 of the FEI 2019 Annual Review application, FEI provided the following table:

Table 6-6: Rate Schedule 46 O&M ($ millions)

	2018		2019
Description	Approved	Projected	Forecast
Tilbury Plant:			
labour	2.540	2.181	2.800
Materials	0.083	0.083	0.105
Contractor	0.719	0.719	0.719
Power	2.847	3.064	3.072
Fuel Gas	0.127	0.125	0.108
Fees & Administration	0.160	0.160	0.160
Sub-total	6.476	6.332	6.964
Mt. Hayes Plant:			
Labour	0.056	0.056	0.153
Materials	0.008	0.008	0.025
Contractor	0.013	0.013	0.054
Power	0.089	0.089	0.200
Fuel Gas	0.008	0.008	0.036
Sub-total	0.174	0.174	0.468
Forecast O&M	6.650	6.506	7.432

28.14 Please confirm, or explain otherwise, that the above O&M represents the "Flow Through" O&M of $6.547 million provided in Table C2-4 on page C-26 of the Application.

Response:

FEI confirms that the $6.506 million under the "Projected" column in Table 6-6 of the FEI 2019 Annual Review application represented the projected "Flow Through" O&M costs in 2018. Table C2-4 from page C-26 of the Application provides the actual 2018 flow through O&M costs of $6.547 million for 2018.

Table C2-5 on page C-26 of the Application shows a Reallocated Flow-through amount of $3.70 million.

28.15 Please provide a breakdown of the Reallocated Flow-through amount using the same cost categories as was provided in Table 6-6 in the 2019 Annual Review application.

Response:

FEI notes that Table C2-5 on page C-26 of the Application shows a Reallocated Flow-Through amount of $3.37 million for 2018 actuals, not $3.70 million as noted in the preamble.

The table below shows the breakdown of the proposed reallocation of the 2018 actuals. Note that the fuel gas costs, which are a variable production cost, are captured as part of the total cost of gas to supply the LNG facility. They are not included as part of the base nor forecast and are therefore not included in the Flow-through O&M table below. Incorporating fuel gas costs within cost of gas is consistent with previous accounting treatment through the term of the Current PBR Plan.

Flow-Through O&M ($ millions)

	2018 Actuals
Tilbury Plant:	
Labour	0.257
Materials	0.302
Contractor	
Power	2.527
Fuel Gas	-
Fees & Administration	-
Sub-total	3.086
Mt. Hayes Plant:	
Labour	0.098
Materials	0.008
Contractor	-
Power	0.178
Fuel Gas	-
Sub-total	0.284
Forecast O&M	**3.370**

28.16 In the same format as was provided in Table 6-6 of the 2019 Annual Review application, please provide the following columns of information: (i) "non-flow-through" portion of the Forecast 2019 O&M of $7.432 million (i.e. the fixed cost portion of the costs); and (ii) the proposed incremental funding in Base O&M of $1.853 million.

Response:

As requested, the fixed cost (non-flow through) portion of the 2019 Forecast from the 2019 Annual Review using the current allocation method is shown in the first column below at $3.767[38] million, and the incremental $1.853[39] million amount using the proposed allocation method is shown in the second column below. FEI notes that this combination of figures is not meaningful, and so has also provided a table that breaks down both columns but using the same proposed allocation method. In the second table below, the first column has been changed to the $9.677 million included in Table C2-6 of the Application.

$ Millions	2019 Forecast Fixed O&M Projection	2019 Base Incremental Fixed O&M
Description		
Tilbury Plant:		
Labour	2.800	0.856
Materials	0.105	
Contractor	0.470	0.295
Power		
Fuel Gas		
Fees & Administration	0.160	0.05
Sub-total	3.535	1.201
Mt. Hayes Plant:		
Labour	0.153	0.215
Materials	0.025	
Contractor	0.054	0.048
Power		
Fuel Gas		
Sub-total	0.232	0.263
Supporting Functions		
Labour		0.230
Employee Expenses		0.020
Contractor		0.139
Sub-total	0	0.389
Total	**3.767**	**1.853**

[38] This amount represents the fixed portion of approved flow-through LNG O&M from the 2019 Annual Review of Rates.

[39] This amount represents the incremental fixed LNG O&M to be added to the 2019 Base O&M as proposed in Table C2-6 (page C-28) of the Application.

1 The table below provides the total Proposed Base which includes the adjusted Base O&M and
2 the proposed incremental funding in Base O&M.

$ millions	2019 Fixed O&M Adjusted Base	2019 Incremental Fixed O&M	2019 Total Proposed Base
Description			
Tilbury Plant:			
Labour	3.936	0.856	4.792
Employee Expenses	0.166		0.166
Vehicles	0.028		0.028
Materials	0.552		0.552
Contractor	0.741	0.295	1.036
Fees & Administration	0.041	0.050	0.091
Facilities	0.104		0.104
Sub-total	5.569	1.201	6.770
Mt. Hayes Plant:			
Labour	1.609	0.215	1.824
Employee Expenses	0.061		0.061
Vehicles	0.016		0.016
Materials	0.226		0.226
Contractor	0.620		0.620
Fees & Administration	0.083	0.048	0.131
Facilities	0.071		0.071
Sub-total	2.687	0.263	2.950
Supporting Functions			
Labour	1.288	0.230	1.518
Employee Expenses	0.102	0.020	0.122
Vehicle	0.014		0.014
Materials	0.003		0.003
Contractor	0.010	0.139	0.149
Fees & Administration	0.002		0.002
Facilities	0.002		0.002
Sub-total	1.422	0.389	1.811
Total	**9.677**	**1.853**	**11.530**

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28.17 Please explain why FEI now expects to require more funding for LNG activities than was forecast for 2019 in the 2019 Annual Review application.

Response:

Since the 2019 Annual Review, FEI has completed an assessment of the plant assets to define the annual maintenance program for the Tilbury Expansion. In addition, FEI has undergone an initial BC Oil & Gas Commission audit, which has validated the regulatory requirements for the Safety and Loss Management Program to be developed and managed by the LNG business unit. As such, FEI has determined the resources it requires to execute the maintenance program necessary for the continued long-term safety and reliability of the Tilbury facility while remaining aligned with the evolving regulatory requirements for all its LNG facilities.

29.0 Reference: FEI O&M BASE

Exhibit B-1, Section C2.4, pp. C-29 – C-42, C-159

New Funding for MRP Term

29.1 Please compare the difference in formula O&M funding which would be provided annually during the proposed MRP term using the escalation factors (i.e. I-Factor, growth factor and productivity factor) approved in the Current PBR Plan versus the Proposed MRP, with the following assumption:

- 2019 Base O&M of $246.269 million (i.e. proposed 2019 Base O&M excluding new funding of $10.416 million) for both plans;

Response:

FortisBC has not produced a forecast of average customer growth and inflation for years 2020 through 2024 for this Application;[40] however, for the purpose of this question, FEI has assumed 1 percent growth in average customers and an I-factor of 2 percent for years 2020 through 2024. Since this analysis is prepared on a forecast basis, FEI cannot differentiate between actual and forecast customer growth so FEI has assumed that they are the same under both scenarios (Current PBR Plan and Proposed MRP funding mechanisms). Therefore, the only differences between the two scenarios below are the elimination of the X-factor of 1.1 percent and the elimination of the 50 percent reduction in the growth factor.

FEI has provided the requested analysis below.

[40] FortisBC did produce a preliminary average customer forecast for 2020 in support of Section C9.4 of the Application (Rate Impacts are Reasonable). This forecast will be updated during the Annual Review for 2020 Rates.

Line	Particulars	Reference	Base 2019	MRP years--> 2020	2021	2022	2023	2024
1	**Formula Cost Drivers**							
2	CPI/AWE	Assumed		2.00%	2.00%	2.00%	2.00%	2.00%
3	Productivity Factor	Approved		-1.10%	-1.10%	-1.10%	-1.10%	-1.10%
4	Net Inflation Factor for Costs	Line 2 + Line 3		0.90%	0.90%	0.90%	0.90%	0.90%
5								
6	Customer Growth Factor	Assumed		1.00%	1.00%	1.00%	1.00%	1.00%
7	50% reduction	Approved		-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
8	Net Growth Factor	Line 6 + Line 7		0.50%	0.50%	0.50%	0.50%	0.50%
9								
10	Inflation Factor for O&M	(1 + Line 4) x (1 + Line 8)		101.40%	101.40%	101.40%	101.40%	101.40%
11								
12	**Current PBR method**							
13	*Gross O&M ($000)*	*Prior Yr Line 13 x Line 10*	*246,269*	*249,728*	*253,235*	*256,792*	*260,399*	*264,056*
14								
15	**Proposed Method**							
16	Gross O&M Base ($000)	Assumption from IR	246,269					
17	AC	2019 projected	1,024,962					
18	O&M per customer	Prior Yr Line 18 x Line 2	240	245	250	255	260	265
19								
20	Forecast of AC	Prior Yr Line 20 x Line 6	1,024,962	1,035,212	1,045,564	1,056,019	1,066,580	1,077,245
21	*Gross O&M ($000)*	*Line 18 x Line 20*	*246,269*	*253,706*	*261,368*	*269,262*	*277,393*	*285,771*
22								
23	*Difference*	*Line 21 - Line 13*		*3,978*	*8,133*	*12,470*	*16,995*	*21,715*

29.1.1 If the resulting annual (and cumulative) formula O&M for the Proposed MRP is higher than for the Current PBR Plan, please explain why this additional funding provided through the proposed changes to the growth and productivity factors is not adequate to accommodate FEI's incremental funding needs for the MRP term.

Response:

The O&M required for FEI to continue to operate safely and reliability and address the challenges in its operating environment is unlikely to be adequately funded by the inflation and growth factors alone, i.e. without the incremental O&M funding requested.

The indexed O&M provides for items that are in support of customer growth or are normal course of business funding needed as part of the operation of FEI. Examples of such items include costs for additional resources to operate and maintain FEI's growing asset base, billing and meter reading activities for customers, contract escalation, and wage increases for

employees. Furthermore, FEI expects these customer growth or normal course of business funding requirements in many instances to exceed that allowed for by the inflation and growth factors during the term of the MRP and has discussed some of them on page C-15 of the Application. As indicated in the Application, FEI expects to manage these cost pressures by relying more on a productivity focus of "doing more with the same".

The specific incremental O&M funding requests included in the Application are over and above that allowed for by the index-based O&M and cannot be considered "normal course operations". These requests are primarily for addressing the changed operating environment and challenges FEI is experiencing. For example, some requests, which have been grouped into the "System Operations, Integrity and Security" category for New Funding for the MRP, are for new activities and initiatives (i.e., Data Analytics, CEPA participation) or represent a substantial increase in funding required (i.e., System Operations, Integrity and Safety) such that it is not reasonable for the cost increases to be accommodated by the index-based O&M alone.

On page C-29 of the Application, FortisBC provides the following table outlining its incremental O&M funding request for the proposed MRP term:

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

On page C-159 of the Application, FortisBC describes the following proposed targeted incentives to be included in the proposed MRP for FEI:

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

29.2 Please explain why it is reasonable for FEI to receive both incremental O&M funding for Customer Expectations and Engagement activities and approval of positive-only targeted incentives for achievement of these activities.

Response:

FEI's incremental funding requests of $1.360 million and $3.360 million for Customer Expectations and Engagement, respectively, are unrelated to the incentive proposed for Customer Engagement.

As noted in Section C8.3.5 of the Application, the Customer Engagement incentive relates to increasing customer adoption of digital service channels, including the use of email, mobile applications, and on-line account services. In contrast, the incremental funding requests noted above are specific to communications channels, such as FortisBC's website and social media accounts that are not measured by the Customer Engagement incentive. The interactions that are measured as part of the Customer Engagement incentive are managed by our Customer Service team, while the incremental funding for Customer Expectations and Engagement supports broader communication with the general public on various topics and is managed by our Corporate Communications and External Relations teams.

29.3 When considering that FEI's benchmark return on equity (ROE) is intended to compensate for utility risk, please discuss what additional risk FEI is undertaking in each of the targeted incentive areas. In particular, what risk is FEI exposed to if targets in each area are not met?

Response:

The premise of the question is incorrect as the authorized return on equity (ROE) and the proposed ROE adder incentives are two separate concepts. The authorized ROE is ordinarily estimated based on financial models such as Capital Asset Pricing Model and/or Discounted Cash Flow in cost of capital proceedings. FortisBC is not asking for a review of its authorized ROE and capital structure in this Application. The ROE adders proposed for Targeted Incentives, on the other hand, are designed to increase utility focus and investments in initiatives that are aligned with government policy and the public interest. The ROE adders are not designed to compensate for utility risk.

Other regulators have used these types of incentives (which are set separate from authorized ROEs) to incent utilities to achieve certain desired targets. For instance, as explained in Appendix C4-3 of the Application, in Brooklyn Queens Demand Management (BQDM) project, New York Public Service Commission (NYPSC) approved a 100 basis points premium over the authorized return (which is set through a separate process) tied to achieving certain outcomes.

The use of an ROE adder as an incentive is only for simplicity and transparency. FortisBC could have expressed the ROE adder incentives in dollar amounts or proposed other forms of incentives (such as increased capitalization of related expenses) that could have had the same effect on the Companies' earnings.

Regarding the second part of the question, the Targeted Incentives are designed to positively incent the Utilities to achieve the targets which are beneficial to customers and in the public interest. If FEI fails to achieve a Targeted Incentive, FEI will have lost the opportunity to earn the incentive and the result may be lower performance and a lower benefit to customers. However, even if FEI does not achieve the incentive, any progress that FEI makes towards the target will still be to the benefit of customers.

30.0 Reference: FEI O&M BASE

Exhibit B-1, Section C2.4, pp. C-29 – C-32; FEI PBR Application proceeding, Exhibit B-1, pp. 156–157

New Funding for MRP Term – Customer Expectations

On page C-29 of the Application, FEI provides the following table:

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

30.1 Please provide the department and account number (based on the account codes provided in the O&M activity view in Appendix A3-1 to the Application) which the "Connect to Gas" and the "In-house Resources to address customer preferences" costs provided in Table C2-8 were recorded in.

Response:

Both Connect to Gas and In-house Resources to address customer preferences costs reside within the Energy Solutions & External Relations department as provided in the O&M activity view in Appendix A3-1 of the Application.

The Connect to Gas costs were recorded in accounts 300-12 Energy Solutions and 300-13 Energy Efficiency while the In-house Resources to address customer preferences costs were recorded in account 300-14 Corporate Communications & External Relations.

30.2 Please provide a detailed breakdown and description of the annual historical expenditures incurred (i.e. 2014 through 2018) for the "Connect to Gas" and the "In-house Resources to address customer preferences" activities.

Response:

FEI notes that due to an addition error in the In-house Resources category, the $0.027 in Table C2-8 for 2017 should be restated to $0.271 million. The updated table is shown below and will be corrected in an Errata to be filed in the near future.

	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	$ 0.271	$ 0.271	$ 0.271	$ 0.431	$ 0.160
Total	$ 1.028	$ 2.172	$ 2.352	$ 2.383	$ 2.547	$ 2.651	$ 4.011	$ 1.360

As requested, a breakdown of historical expenditures from 2014 to 2018 for both Connect to Gas and In-house resources is shown in the table below. Below the table is an explanation of these expenses.

Expenditures (in $ millions)	2014	2015	2016	2017	2018
Connect to Gas					
Natural Gas Appliance Incentives (incl. Stakeholder Engagement)	$0.890	$1.341	$1.338	$1.030	$1.711
Advertising - New Customer Additions & Conversions	$0.087	$0.759	$0.889	$1.082	$0.565
Total Connect to Gas	**$0.977**	**$2.100**	**$2.227**	**$2.112**	**$2.276**
In-house Resources to Address Customer Preferences					
In-house Resources (digital communications)	$0.051	$0.072	$0.125	$0.271	$0.271

Connect to Gas: Natural Gas Appliance Incentives (including Stakeholder Engagement):

FEI offers incentives to encourage customers to switch from other fuels such as oil or propane to natural gas. These incentives are provided to new or existing customers in existing homes, to encourage the use of gas for space and/or space and water heating. The incentives are to help offset the capital cost associated with the installation of these heating appliances and thereby increase the use of gas for heating purposes. Natural gas appliances typically have a higher up-front capital cost as compared to other fuels such as electricity. Offering these incentives can help customers with the added costs. As noted on pages C-31 and C-32 of the Application, incentives have had a positive impact in influencing customers to switch to natural gas and over the term of the Current PBR Plan term FEI increased its spending to encourage the adoption of natural gas. Historically, FEI has spent little on providing workshops, education sessions and other types of stakeholder engagement with builders, developers, and manufacturers for the purpose of advancing gas technology, adoption and use. As such there is

not a historical line item for this activity. However, moving forward FEI is requesting funding so that we can better engage with this important stakeholder group.

Connect to Gas: Advertising – New Customer Additions & Conversions:

FEI invests in advertising activities to raise the awareness of natural gas and educate customers about its benefits including affordability. There was an increase in advertising related expenses from 2015 onwards where the market saw increasing polices that began to restrict the adoption of natural gas. For instance, the CoV's Zero Emissions Building Plan for new buildings to be designed to meet its zero emission building standards would make it challenging to integrate natural gas in new construction projects. FEI ramped up its efforts to promote the affordability and versatility of natural gas by deploying various advertising campaigns targeting Vancouver and the general Lower Mainland region. FEI used multiple media channels during the course of the Current PBR Plan term including print, digital media, advertising in bus shelters, sky trains billboards etc.

In-house Resources (digital communications) to Address Customer Preferences:

The costs associated with In-house resources to address customer preferences also increased over the Current PBR Plan term to address the increasing requirement for online and digital communication channels to engage with FEI customers, stakeholders and the public as also discussed in the response to BCUC IR 1.3.1. Further detail of the changes from year to year include:

- In 2014 and 2015, the cost includes one contract writer, and not full-time capacity;
- In 2016 and 2017, FEI experienced an increase in demand for communications services and used two writers almost at full-time capacity;
- In 2018, FEI had three writers at full-time capacity; and
- The 2019 proposed incremental funding of $0.160 million supports the additional of a Digital Advisor and a Communications Writer / Researcher to continue to meet the growing demand for digital communications with our customers.

Some of the in-house communication activities included initiatives such as:

- Increased use of social media channels Twitter and LinkedIn;
- Launch of Instagram and Facebook social media channels;
- Launch of MyVoice research panel;
- Launch of the mobile app;
- Continuous improvements made to Account Online;

- Launch of the Outage map;
- Development of additional tools and widgets for fortisbc.com, such as calculators, filters for rebates, maps, search tools, etc.; and
- Increased usability testing with customers, which require prototyping and designing mock-ups and wireframes for testing.

30.2.1 As part of the above response, please specifically identify and describe the costs in each year related to (i) Advertising – New Customer Additions and Conversions, (ii) Natural Gas Appliance Incentives (and other incentives), and (iii) Stakeholder Engagement.

Response:

Please refer to the response to BCUC IR 1.30.2. FEI also notes that since it has spent very little historically on Stakeholder Engagement under the Connect to Gas umbrella to engage with builders, developers and manufacturers, these costs are not able to be separated. Accordingly, they are shown together with Connect to Gas incentives in BCUC IR 1.30.2.

30.3 Please confirm, or explain otherwise, that the Connect to Gas initiative was in place at the time of the FEI PBR Application.

Response:

Confirmed. A component of Connect to Gas that was previously known as “Switch n Shrink” was in place during the time of the FEI 2014-2018 PBR Application. It was later incorporated within the Connect to Gas umbrella in 2017 and has become part of the various initiatives that allow FEI to both add and retain customers. In addition, other marketing initiatives that fall under the Connect to Gas umbrella today were active in 2014.

30.3.1 If confirmed, please explain in detail the initiatives in place during 2014 and the areas of focus, and how these initiative and areas of focus have changed and/or expanded during the Current PBR Plan term.

Response:

The Connect to Gas initiative includes the majority of specific marketing activities FEI undertakes to attract and retain its customers. Initiatives under the Connect to Gas umbrella include, but are not limited to: incentives for switching from other energy sources such as propane and oil to natural gas, broad-based advertising campaigns (Gas is Good messaging and education); builder/developer marketing and advertising, and small/short-term incentive programs. These various initiatives have been part of FEI's efforts to attract and retain customers for many years, although often under different banners and in different operating groups.

The activities and initiatives can change year-over-year driven by the opportunities or challenges in the market. Some initiatives may be deployed for a single purpose to address a specific challenge. For instance, in 2012, FEI developed an incentive for builders and developers to encourage them to install tankless on-demand hot water heaters in their projects. This incentive helped trigger the market so that the builder and developer community would consider using this equipment. Once the program achieved its objective, it was discontinued and other initiatives took its place. Other efforts span multiple years such as the incentives to move from propane and oil to natural gas.

In 2014, the main initiatives deployed in the market were the "Switch n Shrink" program and an advertising campaign that targeted conversions using both direct mail and mass media channels.

Over the course of the term of the Current PBR Plan, the Connect to Gas initiative has expanded to meet market challenges and opportunities. Please refer to FEI's response to BCSEA IR 1.30.3 from the FEI 2017 LTGRP proceeding, provided below, that describes the evolution of the Connect to Gas program:

30.0 Topic: "Connect to Gas" (formerly "Switch 'n' Shrink")

Reference: Exhibit B-1, pp.125-126; p.208

"FEI's fuel switching program (previously known as 'Switch 'n' Shrink') supports customer additions and demand growth, and includes initiatives designed to result in lower overall GHG emissions by using natural gas instead of other fuels such as coal, oil, diesel or propane. This program also promotes energy efficiency through installation of new high efficiency natural gas heating equipment."

30.3 Please confirm, or otherwise explain, that "Connect to Gas" (formerly "Switch 'n' Shrink") supports only measures that reduce GHG emissions.

Response:

In 2012, the "Switch 'n' Shrink" program budget was moved from C&EM (then EEC) to O&M per Commission Order G-44-12.

FEI confirms that the previous "Switch and Shrink" program, now an offering that is run under the "Connect to Gas" umbrella, continues to provide customers with rebate incentives that support the reduction of GHG emissions.

The overarching "Connect to Gas" initiative is a branding umbrella under which FEI communicates to customers about becoming a gas customer as opposed to one specific program. Since the rebranding, FEI has expanded its efforts to additional offerings. Under the umbrella, FEI will continue to develop and pilot rebate and other offerings to meet customer needs and demands.

Over the term of the Current PBR Plan, the market landscape for FEI has become more complex with multiple factors constraining or restricting the adoption of natural gas. Under the Connect to Gas initiative, FEI has carried out a variety of initiatives to address the market conditions. For instance, FEI implemented a natural gas literacy advertising campaign in 2015 to educate and inform customers about the use of natural gas. In 2017, FEI rebranded and expanded the "Switch n shrink" program that offers incentives converting from other energy sources such as oil and propane to natural gas under Connect to Gas, which resulted in an increase in customer uptake. In addition, FEI developed incentives to encourage the adoption of natural gas for water heating (when converting space-heating equipment) and appliance rebates for natural gas wall furnaces to encourage the adoption of natural gas.

30.3.2 If not confirmed, please explain why $0.944 million was spent on the Connect to Gas initiative in 2014 and when the Connect to Gas initiative was established.

Response:

Please refer to the response to BCUC IR 1.30.3.

On pages C-29 and C-30 of the Application, FortisBC states the following:

> 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…
>
> FEI is requesting an incremental $1.200 million to continue efforts focusing on customer growth and retention through its "Connect to Gas" activities…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.

On pages 156-157 of the FEI PBR Application, FEI stated the following:

> While cost efficiency and productivity enhancements are critical in managing future potential cost increases, growing the customer base and increasing natural gas throughput also relieves future rate pressures for natural gas customers. As such, in recent years the department has elevated efforts in this area and some of these accomplishments are discussed below.
>
> - The high carbon fuel switching program was successful in increasing customer attachment levels by 94 in 2011 and 98 in 2012…The program provides incentives to customers to switch from higher carbon to lower carbon-emitting fuels through the installation of high efficient ENERGY STAR natural gas heating systems…
> - Working collaboratively with existing and potential customers is critical in ensuring that natural gas forms a part of their future energy portfolio. For example, in 2012 the Energy Solutions team worked closely with the Yorkson Creek (in Langley) townhouse builder/developer to develop an energy solution that included natural gas use and achieved a desirable environmental and energy efficiency standard for homes of EnerGuide 80.

30.4 Please confirm, or explain otherwise, that offering cost effective, accessible and innovative energy solutions was also a focus for FEI when it developed the Current PBR Plan.

Response:

Confirmed. To continue to offer cost effective, accessible and innovative energy solutions remains a foundational area of focus for FEI. The operating environment for FEI is becoming

more complex and challenging with multiple factors making the adoption of natural gas increasingly challenging. As such, FEI will need to increase its efforts to encourage the use of natural gas by investing in programs like Connect to Gas to continue to add and retain customers, which helps keep natural gas rates low for all customers.

30.5 Please explain why, given the successes in customer retention and attachments experienced during the Current PBR Plan with that plan's approved spending envelope, it is not reasonable for FEI to meet its goals during the MRP term with a Base 2019 O&M of $2.380 million for the Connect to Gas initiative.

Response:

As outlined in Section B1 of the Application, FEI's operating environment continues to evolve with a number of federal, provincial and local government policies that will constrain and restrict the use of natural gas as they are implemented. Although FEI has had recent success in customer retention and attachments during the Current PBR Plan period and customer desire for natural gas, climate policy from all levels of government is expected to have a negative impact on FEI's ability to continue to attach and retain customers during the MRP period.

In addition, policy makers at the municipal level are turning to even more ambitious low carbon strategies that are intended to accelerate the transition ahead of CleanBC's target for all new buildings to be "net zero energy ready" by 2032. For example, at the spring 2019 Lower Mainland Local Government Association Conference, members passed a resolution asking the province to incorporate GHG intensity targets directly into the BC Building Code. This is coupled with municipalities exercising authority via re-zoning applications to accelerate the move away from natural gas. Additionally, a growing number of municipalities are now vigorously investigating existing building retrofit strategies at the community scale that align with their low or zero carbon strategies for new buildings, which poses further challenges for FEI to retain existing customer base.

Accordingly, the 2019 Base O&M funds will not be sufficient for FEI to address the challenges it faces over the MRP term. FEI has therefore requested an additional $1.2 million to enable it to compete in the BC energy market space and address the challenges FEI faces in retaining and growing its customer base.

Increasing FEI's investment in programs, incentives and initiatives under the Connect to Gas umbrella that allows FEI to educate, inform and influence customers and stakeholders to

continue to use natural gas will better position FEI to continue to provide affordable energy to British Columbians.

30.6 Please explain why FEI considers it necessary to focus its efforts on customer retention during the proposed MRP term. As part of this response, please explain what market signals have been present to suggest that customer retention is an issue for FEI.

Response:

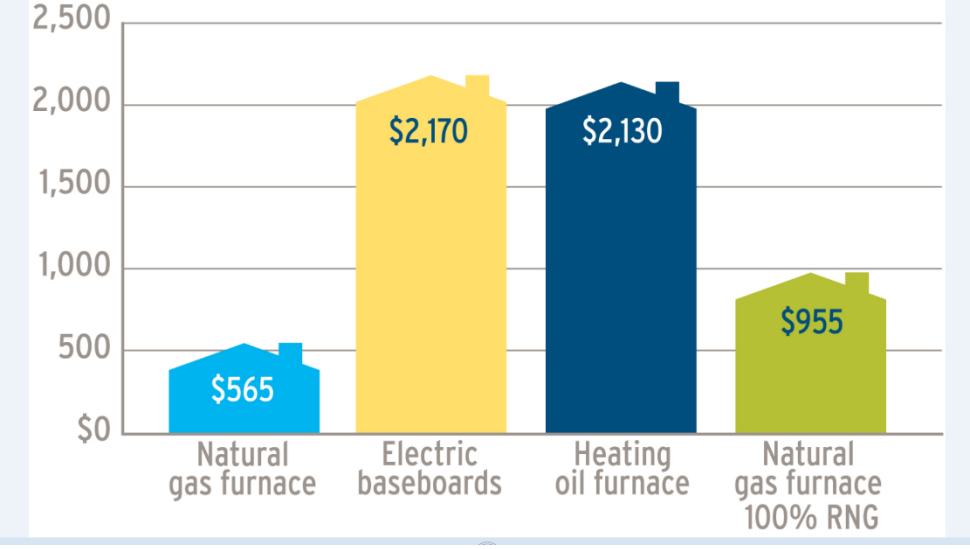
Please refer to the response to BCUC IR 1.3.6, 1.13.11.1 and 1.30.5.

30.7 Please compare the cost of natural gas as a heating source compared to other alternatives and discuss how FEI expects this comparison to change (if at all) during the MRP term.

Response:

Based on BC Hydro's 10 year rate plan projection, FEI expects that the price gap between natural gas and electricity may be somewhat reduced over the next five years. The funds being requested are required to address longer-term challenges in the market. While there is an operating price advantage for natural gas, this advantage is not a benefit if FEI is not able to deliver gas to its customers due to building code restrictions such as greenhouse gas intensity. As such, FEI must act immediately to ensure customers know the benefits, including price, of natural gas.

Natural gas at today's rates is competitively priced compared to other heating options. Currently, natural gas is less that 1/3 the price of other energy sources such as electricity and furnace oil, (as shown in the graph below). The graph compares the cost of heating a home with natural gas, electricity and renewable natural gas (note that the cost of heating with natural gas includes commodity, delivery, midstream and carbon tax). This cost comparison is based on a 2,300 square foot home with average insulation, using prices in effect as of April 2019.



While the price currently favours natural gas, that advantage is only in place if FEI is able to provide gas service to customers. As noted in the response to BCUC IR 1.30.5, FEI's operating environment continues to evolve with a number of federal, provincial and local government policies that will affect FEI's ability to add and retain customers. If policies restrict the use of natural gas, such as the CoV 2025 policy for zero emission space heating and hot water, customers will not be able to benefit from the price advantage of natural gas as it will not be in their building.

Also, during the course of the MRP term, FEI expects the cost of natural gas will increase as a result of increases in carbon taxes. And in the longer term, as more renewable energy sources are integrated into the gas distribution system, such as RNG and other low carbon fuels, this will impact the cost of gas, reducing its price advantage.

Lastly, when comparing costs, it is also important to consider other cost components such as equipment costs, construction costs, design and installation costs. The up-front capital costs of gas equipment compared to the cost of electric heating equipment is generally higher. A typical costs for installing electric baseboard heating in a 3,000 square foot single-family home is between $5,500-$6,000 (this includes the cost of the baseboard equipment and ventilation that is required per the building code). Heating equipment for the same house with a forced air system such as a natural gas furnace will cost between $7,500-$9,000. Similarly domestic hot water heating with electricity for a 60-gallon electric tank is approximately $1,600 (includes installation and permitting). Natural gas hot water tank of the same size is about $2,100.

In general, the up front costs of natural gas are higher and can add a layer of complexity to the project due to the need for additional space requirements for equipment and venting, permitting, design, engineering and trades. As a result, FEI must keep up its efforts to work with customers and developers to choose natural gas.

On page C-30 of the Application, FEI provides the following 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

On page C-31 of the Application, FEI states that it "needs to increase 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 further states on page C-31 that it "will also need to increase its communications efforts to respond to the changing market landscape…The goal is to maintain or grow throughput on the system by educating and informing customers about the use of natural gas."

30.8 Please provide FEI's actual annual advertising spending during the Current PBR Plan term.

Response:

FEI interprets annual advertising spend to include the activities and initiatives it undertakes to promote natural gas and other products offered by FEI (such as RNG, NGT, safety, and DSM). Activities include, but are not limited to, utilizing channels such as radio, digital, social media, "out of home" advertising such as bus shelters, sky train, billboards etc. The table below provides a breakdown of FEI's annual advertising spending during the Current PBR Plan term.

FEI Advertising Expenditure ($ millions)					
2014	2015	2016	2017	2018	Total
$3.400	$4.102	$4.264	$3.351	$6.776	$21.894

These expenses include advertising for multiple areas and initiatives within FEI such as safety, conservation and energy management, natural gas for transportation, renewable natural gas, energy solutions (connect to gas initiatives), and capital projects. Not all of these amounts are included in O&M.

30.9 Please provide a detailed breakdown and description of the incremental $600,000 for advertising. As part of this response, please explain why each of the activities identified and the associated incremental costs are expected to be undertaken/incurred throughout the entire MRP term.

Response:

As noted in the response to BCUC IR 1.30.3.1, FEI undertakes a broad range of activities to help add and retain customers under the Connect to Gas umbrella. The deployment of the initiatives is based on specific opportunities or challenges that FEI faces in the market. FEI has not pre-determined all of its advertising activities over the entire MRP term as they will be driven by the market landscape and opportunities or threats at that point in time. However, for 2020 FEI's current plan is to allocate the increased $600 thousand in the following areas:

- Cooking with Gas Campaign - $250 thousand: This campaign will promote the use and versatility of natural gas for cooking. Campaign activities may include sponsorship of cooking shows, collaboration with food industry experts and media advertising;
- Energy Literacy Campaign - $250 thousand: This campaign will focus on educating customers on the benefits of natural gas such as comfort, convenience and affordability as well as how natural gas is an important driver of the BC economy. An integrated media plan will be used to maximize outreach using media channels including digital, print, and mobile; and
- Conversion Campaign - $100,000: This campaign will promote the benefits and simplicity of switching from other fuels such as oil or propane to natural gas. The campaign will inform customers on the incentives that are available for customers to help offset a portion of the capital cost of purchasing a natural gas furnace.

Over the remaining course of the MRP term, FEI envisions that it will continue to deploy advertising campaigns to respond to the market by launching targeted campaigns as the market shifts. FEI has also used "Out of Home" advertising that uses billboards, bus shelters, skytrain platforms to promote the adoption of natural gas. Other examples are provided in the response to BCUC IR 1.30.2.

FEI anticipates that over the MRP term it will continue to leverage these type of activities and channels, but will need to increase the frequency and scope. For instance, with the current limited funds under the Connect to Gas initiative, FEI must take a regional approach to advertising. FEI plans to take a broader provincial approach to promoting natural gas, and as part of that, expand to channels such as TV to reach a broader audience.

30.10 Please provide the analysis that FEI has conducted which supports the conclusion that increased communication efforts will achieve its desired outcomes. As part of this response, please identify each specific goal and the specific communication efforts which are expected to achieve this goal, and the basis for this expectation.

Response:

In 2018, FEI contracted the services of Sentis Market Research Inc. (Sentis) to help FEI evaluate the effectiveness of its communication strategy to assess if, and how, the communication messages are influencing customer awareness, attitudes and behaviour and to get a pulse on natural gas literacy.

The results of the survey conducted by Sentis indicated that the natural gas literacy index was on the decline. The natural gas literacy index measures awareness of FEI as a BC energy utility, impressions of natural gas, and the extent to which natural gas is a preferred energy source. The survey also indicated a slight downward trend in receptivity of purchasing a home with natural gas as an energy source. Another finding was that respondents view natural gas more for hot water heating than space heating.

FEI also contracted the services of Innovative Research Group in 2018 to conduct research on customer preferences to understand the attitudes and knowledge of natural gas. This survey revealed that 48 percent of respondents thought that natural gas was the same price or more than electricity, reinforcing that customers are unsure about their energy costs and don't know that natural gas is approximately one-third the price of electricity.

Further, during the Enbridge pipeline rupture in October 2018, it became evident that customers did not understand their energy systems or costs.

FEI believes that an increase in communication activities will lead to desired outcomes of improved literacy, attitudes and awareness of natural gas.

FEI's experience with public communication provides support for this belief. For example, in 2010, only 15 percent of survey respondents knew the smell of natural gas and recalled the two steps to take if they smelt gas (leave the dwelling and then call FEI/911). In response, FEI increased its advertising expenditures to improve public knowledge related to natural gas safety. Between 2011 and 2018, the percentage of respondents who were categorized as prepared to handle a gas emergency increased from 15 percent to almost 50 percent. These findings reinforced that FEI needs to invest in increasing its communication efforts to inform and educate its customers.

During the course of the MRP term, FEI will continue to leverage communication channels it has used in the past such as print, digital, radio, social media etc. and will also explore channels it has not used actively before such as TV, to educate and inform customers about the affordability of natural gas and its applicability to space and hot water heating. FEI has not determined its detailed communication initiatives for the entire MRP term as these will be based on the specific needs in the market at the time. However, FEI's response to BCUC IR 1.30.9 includes a breakdown of anticipated expenses associated with advertising and communication in the first year of the MRP term.

30.11 What has led FEI to believe that customers are not sufficiently aware of the programs under the "Connect to Gas" umbrella and/or the incentives available?

Response:

FEI believes that many residents are not aware of FEI's program offerings under Connect to Gas as our customers are telling us that. Our Energy Solutions staff field several thousand enquiries on an annual basis from individuals seeking information on connecting to natural gas. Only approximately half of these may be aware that we offer rebates, and very few are aware of the specifics of the rebates, including the rebate amounts and what appliances are eligible.

For instance, when FEI receives a request for gas service to a neighbourhood that is currently not served by natural gas, there are customers who inform us that they were unaware of our incentives or programs. In early 2018, we received one request for gas service on Stable Place in Nanaimo. Our Energy Solutions Manager canvassed the street and developed enough interest to move the project to construction with 2 customers expected to connect. While our crews were on site installing the main, several of the neighbours became interested and enquired about connection fees, energy savings and rebates. By the time the main was completely installed, 7 new customers were connected to the system. This example demonstrates the opportunity to continue growing customer awareness of the Connect to Gas program.

To date, FEI has only promoted programs under Connect to Gas regionally. For instance, most of the promotion activities have been focussed on Vancouver Island. Customers outside of Vancouver Island are less aware of the program.

In addition, as noted in FEI's response to BCUC IR 1.30.10, natural gas literacy is declining overall. As such, FEI believes it needs to increase its efforts further to promote its offerings

under the Connect to Gas umbrella. This will ultimately benefit customers through increased growth and load on the system.

30.12 What types of communication activities does FEI believe are required to be undertaken which are not currently being undertaken? Please explain.

Response:

The communication and advertising activities that FEI undertakes over the MRP term will be guided by the specific challenge or opportunity in the market. As noted in FEI's response to BCUC IR 1.30.9, FEI has planned communication and advertising initiatives for 2020 that include diverse activities. Beyond the first year, FEI has not mapped out specific communication initiatives yet as they will be determined based on the market landscape closer to that time. FEI foresees the continued use of channels it has in the past (print, digital, mass media) to educate, inform and influence customers about the benefits of natural gas. In order to address the complex market environment, FEI would like to increase the volume and frequency of communication activity for broader outreach.

On page C-31 of the Application, FEI states that it 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."

30.13 Please confirm, or explain otherwise, that all of the incentives offered by FEI are contained within the "Connect to Gas" initiative.

Response:

Most of the activity that FEI undertakes to encourage the use of natural gas, to enable FEI to add and retain customers, is conducted under the umbrella of Connect to Gas. However, FEI also offers incentives outside of Connect to Gas, which are managed by other business units. DSM incentives are offered to encourage the use of high efficiency natural gas appliances, and natural gas for transportation incentives are offered to encourage a switch from higher carbon fuel sources such as diesel to CNG or LNG.

30.14 Please provide a detailed breakdown and description of all of the types of incentives offered by FEI annually during the Current PBR Plan term.

Response:

The following table provides a breakdown of the incentives offered by FEI during the Current PBR Plan term.

FEI Incentives	(Expenditures in $ millions)				
	2014	2015	2016	2017	2018
Connect to Gas Incentives	$0.89	$1.34	$1.34	$1.03	$1.71
DSM Incentives[1]	$16.60	$20.98	$21.05	$21.84	$21.57
GGRR Incentives[2] (see BCUC IR 1.73.11)	$9.97	$6.32	$4.77	$13.35	$10.07
Total Incentives	$27.45	$28.64	$27.15	$36.22	$33.35

[1] *Includes incentive spending only.*
[2] *GGRR Incentive expenditures include expenditures on the following items as permitted under the GGRR: vehicle incentives, safety and maintenance shop upgrade incentives, admin/marketing/training expenditures*

The Connect to Gas Program incentives are described in the response to BCUC IR 1.30.2. DSM incentives are offered to residential, commercial and industrial customers to encourage installation of high efficiency natural gas equipment. FEI also offers incentives for NGT under the GGRR to commercial and industrial customers to support the adoption of natural gas vehicles and marine vessels.

30.15 Please clarify if the incremental funding of $0.350 million is related to existing incentives, proposed new incentives, or a combination of both. Please also provide a breakdown and a description of the types of incentives the $0.350 million would be used for.

Response:

The funding request is for a combination of both existing and new incentives.

For instance, FEI plans on continuing to provide existing initiatives that encourage customers to convert from fuels such as oil or propane to natural gas. These incentives have proven to be successful over the course of the Current PBR Plan term to encourage greater adoption.

FEI also plans to introduce new incentives for natural gas equipment to encourage the market to use natural gas appliances for space and hot water heating solutions, which is an area where FEI faces its biggest challenges. FEI will also look to offer incentives for new equipment technologies such as combi-units that provide a combination of space and domestic hot water heating and possibly natural gas heat pumps which is a relatively new technology in BC.

FEI has not pre-determined all the incentives that will be offered over the MRP term; deployment will be based on the opportunity or challenge in the market at the time.

30.16 Are there any types of incentives and/or incentive programs which were included as part of the Current PBR Plan's Base O&M which are no longer in place or have limited effectiveness? If yes, please describe these incentives and whether the funding for these has been re-purposed (and how). If no, please explain why not.

Response:

There are no incentives that were being undertaken at the time that the Base O&M was set for the Current PBR Plan that are no longer in place. The "Switch n Shrink" program was rebranded in 2017 and moved under the Connect to Gas umbrella. Prior to the Current PBR Plan term, FEI provided targeted incentives for the adoption of on-demand water heaters in multi-family buildings which did not continue past the initial implementation.

On pages C-31 and C-32 of the Application, FortisBC states the following:

> 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…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.

30.17 Please clarify how the incentives helped to influence new conversion customer additions, including whether the conversion customers stated in the above preamble received incentives.

Response:

Incentives assist in offsetting a portion of capital costs involved in switching to natural gas from other fuel sources such as oil or propane. The upfront capital cost of natural gas equipment generally is more expensive compared to alternative equipment such as electric baseboards so the incentives offered by FEI make it more economically feasible for customers to switch to natural gas.

In 2014, of the 1,799 conversion customers, 763 customer received incentives. In 2018, of the 4,486 conversion customers, 1,312 received incentives.

30.17.1 If the conversion customers in the above preamble did not receive incentive funding, please explain the correlation between incentive funding and customer conversion.

Response:

Incentives help increase the number of conversion customers attaching to the natural gas system but not every conversion customer receives a Connect to Gas incentive.

Connect to Gas incentives are provided to new or existing customers, in existing homes, to encourage the use of gas for space and/or space and water heating. The incentives are to help reduce the cost of these heating appliances and thereby increase the use of gas for heating purposes.

There are conversions that occur without incentives either because the customer did not know about the offer, or because the customer was not eligible as the customer had a barbeque, cooktops, fireplaces etc., but not a heating appliance.

30.18 Please describe in detail the other factors which likely contributed to the 150 percent increase in conversion customers since 2014 and how these factors are expected to impact the rate of customer conversions during the proposed MRP term.

Response:

An increased allocation of spending to the Connect to Gas initiative has influenced the increased customer participation in the program. FEI deploys a broad spectrum of activities under its Connect to Gas umbrella and, to promote conversion attachments, FEI leveraged a number of channels to raise awareness of the incentives available. For example, promotion of the program through FEI's Trade Ally Network members has raised awareness of the program. Investing in educating customers on the benefits of using natural gas has also contributed to greater uptake in the program. FEI's Energy Solutions Managers have worked actively with potential conversion customers to inform them about the incentives available from FEI. Lastly, FEI increased advertising in areas of high conversion potential such as Vancouver Island.

30.18.1 As part of the above response, please identify the factors which FEI considers to be within its control and the factors it considers to be primarily outside of its control.

Response:

FEI is able to influence and motivate actions by customers and stakeholders to take specific actions. However, FEI would not consider that it has control of the factors that are affecting its business. For example, FEI can encourage a developer to use a gas appliance, but it does not have control of a developer's decision.

Factors that FEI believes to be within its sphere of influence include the ability of FEI to promote the use of natural gas, educate and inform customers on the energy costs and available equipment solutions, and provide incentives that drive market adoption of certain solutions. For instance, by providing incentives, FEI is able to encourage customers using higher carbon fuel (oil, propane) to switch to natural gas. FEI has seen success in increasing conversion customers by investing in these incentives.

FEI is also able to influence the market to adopt certain equipment or technologies. For instance, over the Current PBR Plan period, FEI worked with builders and developers to adopt natural gas heating equipment in their projects and provided incentives for equipment like

combi-units[41] and wall furnaces. These incentives proved to be effective and the developer community has started to embrace this equipment.

In addition, FEI's Energy Solutions team works very closely with key stakeholder groups such and builders, developers, architects, engineers and contractors to keep them abreast of natural gas solutions and benefits. FEI's advertising campaigns to promote the use of natural gas is also an area that FEI can influence; however, the impact is based upon the amount of funding available under the Connect to Gas initiatives which support activities to add and retain customers.

On page C-32 of the Application, FEI states that it requires $0.250 million of incremental funding for "Collaboration with Stakeholders", which includes "investment in activities such as lunch and learn sessions, campaigns, collaborative case studies and pilot programs."

30.19 Please explain the types of "collaborative case studies" which FEI plans to undertake, the types of stakeholders which would be involved and the purpose of the case studies.

Response:

FEI has a diverse group of stakeholders it engages with including builders, developers, architects, engineers, manufacturers, contractors and retail partners. FEI will undertake activities based on the stakeholder it engages to ultimately encourage and promote the adoption of natural gas solutions. In doing so, FEI will continue with a number of activities it has conducted in the past that have produced positive outcomes.

For example, FEI's team of Energy Solutions Managers will host lunch and learn sessions quarterly or as needed to educate and inform builders and developers about commercially available new natural gas technologies and solutions. Similar types of sessions will be held for contractors who install natural gas equipment. FEI will also participate in collaborative case studies and pilot programs to promote the adoption of natural gas energy solutions. For instance, FEI has collaborated with developers to pilot the use of "combi-system" heating solution to get the market to accept it as a viable heating option. FEI will consider collaborating on additional projects as they have demonstrated positive results.

[41] A combi-unit refers to equipment that provides a combination of space heating and hot water.

30.20 Please explain the types of pilot programs FEI plans to undertake.

Response:

FEI has undertaken pilot programs to encourage the market to adopt natural gas energy solutions. Pilot programs help demonstrate new or non-mainstream technologies to the market thereby increasing their adoption. During the MRP term, FEI expects to conduct pilot projects that encourage the adoption of natural gas solutions. For example, FEI is considering a piloting a gas-fired heat pump solution that is not yet widely used in BC. Other potential pilot programs could be for natural gas fuels cells, combined heat and power.

30.21 Did FEI undertake any collaborative case studies and/or pilot programs during the Current PBR Plan term? If yes, please provide a description and the costs of each case study/pilot program.

Response:

FEI has had limited O&M funds to undertake case studies/pilot programs during the Current PBR Plan term to encourage the adoption of natural gas equipment in working collaboratively with developers. The pilot programs that are listed below are those that were done in collaboration with the Energy Solutions team, a builder/developer and the C&EM innovative technology program as they result in energy savings measures. The objective of the pilot programs was to encourage the market to implement a natural gas solution for heating that was not widely adopted. Additional funds will enable FEI to undertake additional collaborative case studies that do not fit under the DSM umbrella.

Gas Combi-Unit

FEI collaborated with a developer who has traditionally built their projects using electric baseboard heating and hot water heating appliances. After multiple engagements with the developer, FEI's Energy Solutions Managers were able to encourage the developer to consider installing a natural gas "combi-unit" solution that was relatively new to the market. A "combi-unit" is a combination heating and domestic hot water system that can be used in both retrofit and new construction residential applications that allow for space heating and domestic hot water

integration between tankless water heater and hydronic air handler. FEI also leveraged the expertise of an industry expert who was able to educate the developer on the technology and its features. FEI offered an incentive of $1,500 per unit (total potential cost $330 thouand) and convinced the developer to pilot “combi-units” in their 220 unit new development in the Lower Mainland. As the project is still in progress, FEI has not yet disbursed the funds to the developer. The adoption of this equipment results in energy savings measures; as such this pilot program was funded partially by the C&EM innovative technology program.

Integrated Gas Combi-Unit

In another example, FEI collaborated with a developer also in the Lower Mainland who is building a 22 unit townhouse development. In this instance, the pilot program was to demonstrate a similar technology as the “combi-unit” except that it is enclosed into a single integrated unit. The incentive was $2,000 per unit for a total cost of $44 thousand. This pilot program was funded through the C&EM innovative technology program.

The intention of these pilot programs was to give builders and developers confidence in the technology and demonstrate that it can provide domestic hot water and continuous space heating along with saving energy. FEI has already experienced success in encouraging market adoption in one of the developments close to the pilot site where combi-units are being piloted, and another developer in the same area that has decided to use the technology without FEI incentives.

The construction landscape continues to evolve along with the policy environment that make natural gas adoption and solutions more challenging to implement. To enable FEI to continue to grow the natural gas customer base, FEI needs to be able to meet the growing need to work with builder/developers. This requires working collaboratively with them to explore new technologies and building practices, which may or may not meet DSM criteria, but entail novel and not widely adopted natural gas solutions.

30.22 Please explain why costs related to case studies and pilot programs would not be funded through the proposed Innovation Fund (if approved).

Response:

The funds under the Connect to Gas umbrella are used to encourage the adoption of commercialized natural gas solutions. Please refer to the response to BCUC IR 1.30.21 for examples of pilot programs. In contrast, the proposed Clean Growth Innovation Fund, as noted

in Section C-6 of the Application, is aimed at research and development of new technologies to provide customers with clean and cost effective energy sources in the future.

On page C-32 of the Application, FEI states the following:

> 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.

30.23 Please explain how many years FEI has been utilizing each of the non-traditional communication channels described in the above preamble.

Response:

Below is a table outlining how long FEI has been utilizing each of the non-traditional communication channels described above.

Communication channel	Year started	Years active
Text messaging	N/A	N/A
Mobile app	2017	<2
Social media - Twitter	2009	10
Social media - Youtube	2007	12
Social media - LinkedIn	2013	5
Social media - Instagram	2015	4
Social media - Facebook	2018	<1

30.24 Please confirm, or explain otherwise, that FEI has been implementing and utilizing technologies such as mobile applications to improve ease of access for customers to account information during the Current PBR Plan term.

Response:

As discussed in the response to BCUC IR 1.3.1, 28 percent of gas customers suggested their preferred communication channel is Account Online in 2018 versus 16 percent in 2013. Additionally, 63 percent of FortisBC customers indicated they preferred to access natural gas vendor information from FEI's website. These results are indicative of the overall trend that customers are increasingly seeking to communicate through digital channels due to their convenience and ease of access. While FortisBC has been advancing the use of these channels, customer preferences represent a step change in recent years.

For example, FortisBC's website was redesigned and relaunched to include a fully responsive website for mobile devices in January 2019. Since the relaunch in January, FortisBC has already experienced an increase of 3.1 percent in mobile device use when compared to the same period in 2018.

Another growing trend is customers' use of social media channels to send messages directly to FortisBC inquiring about their account information, construction work by their home, connecting to the natural gas system, etc. Customers expect an accurate and timely response from FortisBC which requires internal coordination to respond accurately.

The growth in demand for online platforms is expected to continue. Customer expectations to self-manage their energy use is driving the need for additional online and/or digital resources to meet this expectation and provide customers with convenient platforms to share and access information. Accordingly, FortisBC is evaluating new modes of digital communication such as web chat, smart speaker, and smart device as suggested by a recent Esource study on Customers' Contact Channel Preferences. Please refer to Attachment 30.24 for a copy of the Esource study.

On page C-32 of the Application, FEI states: "Additional in-house resources including a Digital Advisor and Communications Writer/Researcher are required to support these activities."

30.25 Please clarify if the Digital Advisor and Communications Writer/Researcher are one position or two separate positions and provide a detailed description of the roles and responsibilities of the position(s).

Response:

The Digital Advisor and Communications Writer/Researcher are two separate positions.

The Digital Advisor is a Management and Exempt position whereas the Communications Writer/Researcher is a bargaining unit (MoveUP) position. Each is described below.

Communications Writer/Researcher

The Writer position researches relevant sources and writes copy for different audiences and different communication media such as: key messages, print, television and radio advertising material, websites, newsletters, brochures, bill inserts, print pieces and other digital communications pieces such as, adwords, display banners, social media posts, blogs, etc. The Writer/Researcher also performs the following:

- Interviews participants as part of a written piece;
- Researches information and cites sources appropriately; and
- Reviews and edits copy according to Canadian Press style.

The education this role requires is a post-secondary education in English, Communications, Journalism, Professional Writing or equivalent education.

Digital Advisor

The Digital Advisor researches, makes recommendations on new web tools, applications, information architecture, user experience, analytics, social media channels (including blog) and monitoring tools, paid digital advertising opportunities, email/enewsletters, search engine optimization and mobile applications. In addition, the Digital Advisor looks to optimize all of FortisBC's presence online, on the corporate websites, as well as, outside of the corporate website, such as:

- Improve search on Google and other search engines;
- Improve page load times;
- Test user experience from desktop to tablet to mobile; and
- Utilize best practices to engage with followers on various social media channels (Twitter, Facebook, LinkedIn, Instagram, Youtube), etc.

The education this role requires is post-secondary education in Marketing, Communications or a related discipline.

These roles and responsibilities cannot be performed by one person as the technical competencies required from each role are different and the positions are in two separate affiliations.

Regarding the proposed incremental funding, the Digital Advisor, Communications Writer/ Researcher and Digital Communications Advisor requests relate to three incremental positions. This work was initially contracted out to consultants to help manage work peaks, but with increased requirements, FEI plans to add incremental resources and bring this expertise in-house at the same time in order to manage the workflow.

The work to be done by these positions, as described in the response to BCUC IR 1.30.2, continues to grow and additional resources are needed to keep up with the demand for continuous website updates, searches for new and relevant content, sharing information on social media, monitoring analytics and running reports to support major project consultation, etc.

30.26 Please explain why this role cannot be performed by existing resources and who has been managing/performing the role of communications for digital and social media currently.

Response:

The Digital Advisor, Communications Writer/ Researcher and Digital Communications Advisor requests relate to three incremental positions. This work was initially contracted out to consultants to help manage work peaks, but with increased requirements, FEI plans to add incremental resources and bring this expertise in-house at the same time in order to manage the workflow.

The work to be done by these positions, as described in the response to BCUC IR 1.30.2, continues to grow and additional resources are needed to keep up with the demand for continuous website updates, searches for new and relevant content, sharing information on social media, monitoring analytics and running reports to support major project consultation, etc.

31.0 Reference: FEI O&M BASE

Exhibit B-1, Section C2.4, pp. C-32 – C-36; Exhibit B-1-1, Appendix A3-1; FEI PBR Application proceeding, Exhibit B-1, p. 161

New Funding for MRP Term – Engagement

On page C-33 of the Application, FEI provides the following table:

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

31.1 Please provide the department and account number (based on the account codes provided in the O&M activity view in Appendix A3-1 to the Application) which the three activities listed in Table C2-10 are recorded in.

Response:

The department and account number for the three activities listed in Table C2-10 is Corporate Communications & External Relations reference 300-14 in Appendix A3-1.

31.2 Please provide a detailed breakdown and description of the Actual 2017 and 2018 costs incurred for the "Climate Action Partners program" and the "Other Supporting Resources."

Response:

Please find below a breakdown of the Actual 2017 and 2018 costs incurred for the Climate Action Partners Program. This table of costs does not include the two Program Manager and Co-op Student roles that were added in 2018 and 2019 to assist with program development, management and delivery. In the early stages of the program, FortisBC was focused on providing resources in the form of contract labour to support municipalities and other organizations in achieving their climate goals.

DSM funding was incorporated to the program funding based on work plans that support FortisBC's Conservation and Energy Management programs and initiatives. Since building a

number of initial program relationships with local governments in 2017 and 2018, FortisBC has started to expand the Climate Action Partners program to additional local governments as well as develop partnerships with other stakeholder types including Indigenous communities, non-profit organizations and academia. FortisBC plans to further build out the Climate Action Partners program by providing targeted support to stakeholders such as workshops to generate dialogue on climate action and clean energy solutions for BC.

$ millions	2017	2018
Contractors	$ 0.391	$ 0.166
Targeted support	$ 0.008	
Partnerships	$ 0.011	$ 0.030
Travel & meals	$ 0.002	$ 0.012
Legal fees	$ 0.010	
Admin	$ 0.002	$ 0.003
TOTAL	**$ 0.414**	**$ 0.211**

Please note that the detailed breakdown of the expenditures in Table C2-10 above includes O&M expenditures only. The Climate Action Partners program also includes funding from DSM and GGRR. Please refer to the response to BCUC IR 1.31.7 for more information on DSM and GGRR funding.

Please find below a summary of the Other Supporting Resources for 2017 and 2018. This expense was for contracting out for web services support at a cost of $110 thousand per year for the last two years.

$ millions	2017	2018
Contractors	$ 0.110	$ 0.110

On page C-33 of the Application, FortisBC states: “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.”

FortisBC further states on page C-33: “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."

31.3 Please clarify FortisBC's statement in the above preamble that "no funding has been allocated to increasing awareness of FEI's products and services and their fit within a lower carbon economy" given the existence of FEI's Connect to Gas program.

Response:

As noted in the response to BCUC IR 1.30.3.1, the Connect to Gas initiative includes the range of activities that FEI undertakes to attract and retain its customers, whereas the incremental funding request for increasing awareness of the role of natural gas within a lower carbon economy supports communication of a much broader message to the public similar to public safety and energy efficiency messages. These messages speak to the benefits of natural gas in today's competitive, low carbon economy, including its contributions to lowering costs and emissions through applications like natural gas for transportation, renewable natural gas, liquefied natural gas, compressed natural gas, as well as for home heating.

31.4 Please explain why FEI considers it necessary to receive incremental funding of $0.600 million for advertising related to the Connect to Gas program as well as $2.0 million for advertising for "Raising Awareness for Consumers in a Lower Carbon Future". As part of this response, please clearly explain how these funding requests differ and why separate funding is needed for both activities.

Response:

As described in the response to BCUC IR 1.31.3, these are two different programs and are targeted at different audiences. Therefore, the two programs require the development of separate content, separate communications streams, events, workshops, sponsorships and advertising targeted at different audiences.

On page 161 of the FEI PBR Application, it described the following planned initiative during the Current PBR Plan term:

- Customer Education, Awareness, and Outreach Programs
  This initiative is aimed at increasing preferences and demand for natural gas use through comprehensive customer education, awareness and outreach programs. These programs are critical in mitigating the market shift in demand, in particular for natural gas space heating and domestic hot water use. Growing demand for natural gas products, through educating customers of the benefits of using natural gas in managing their energy portfolio will continue to be a critical element to the Company's future success. This initiative accounts for $1 million of the increased spend in 2014.

31.5 Please clarify FortisBC's statements on page C-33 of the Application that "no funding has been allocated to increasing awareness of FEI's products and services and their fit within a lower carbon economy" in consideration of the initiative described in the FEI PBR Application.

Response:

Please refer to the response to BCUC IR 1.31.3 where FEI has confirmed that this initiative is distinct and has not been funded to date.

On pages C-34 and C-35 of the Application, FortisBC describes the incremental funding request of $1 million for the Climate Action Partners program, stating the following:

> Funding additional Senior Energy Specialist roles. For these roles, FEI provides funding to various levels of government, Indigenous communities and other organization to hire a person to implement a pre-defined work plan that aligns with the organizations' energy objectives…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…Total funding for these positions ($1.650 million) will come from approved DSM funding ($1.080 million) and O&M funding ($0.570 million).

31.6 Please explain if the nine Senior Energy Specialist roles currently in place are funded through Demand Side Management (DSM) funding, O&M or a combination of both. If the funding is from a combination of both, please provide the amount of funding from each source.

Response:

The Senior Energy Specialist roles are funded through a combination of DSM funding and O&M because their work plans may include work related to initiatives that fall outside of FortisBC's Conservation and Energy Management program areas. These other work items may include examining ways to develop RNG supply, expanding the use of natural gas in medium or heavy duty transportation applications, or policy-related initiatives such as corporate or community energy and emissions planning. Below is a breakdown of funding from each source:

O&M	$0.570 million
DSM	$0.900 million
NGT	$0.180 million
Total	$1.650 million

31.7 Please explain if the DSM funding of $1.080 million was specifically approved in FEI's most recent DSM application with the BCUC or if FEI has determined the amount to be used from DSM funding.

Response:

The $1.080 million noted on Page C-35 of the Application is made up of funding from multiple sources as indicated in the response to BCUC IR 1.31.6, as the Senior Energy Specialists roles work on a variety of low carbon initiatives such as Demand Side Management (DSM), RNG, and NGT.

FEI and FBC DSM funding approved in the 2019-2022 DSM plans for Senior Energy Specialist roles is $0.900 million collectively. There is also partial funding of $0.180 million from NGT.

For greater clarity, the comment in Table C2-11 regarding funding sources for the Climate Actions Partners Program has been restated below (additions are underlined):

> "Total funding $1,650 thousand with $570 thousand funded in O&M and remaining $1,080 as part of CE&M <u>and NGT</u> funding. <u>$750 thousand as part of FEI DSM funding, $150 thousand as part of FBC DSM funding and $180 thousand from NGT funding."</u>

31.7.1 If the $1.080 million was not specified through FEI's most recent DSM application (and approved in the most recent DSM decision), please explain how FEI determined the allocation of funding between DSM and O&M, and why FEI does not fund 100 percent of the $1.650 million through DSM.

Response:

As discussed in the response to BCUC IR 1.31.7, $0.900 million was the approved amount for 2019 in the FEI and FBC 2019-2022 DSM plans for Senior Energy Specialist roles ($0.750 million and $0.150 million for FEI and FBC respectively).

As noted in the responses to BCUC IRs 1.31.7 and 1.31.10, FEI does not fund 100 percent of Senior Energy Specialist roles through DSM as the specific work plans on initiatives may fall outside of FEI's Conservation & Energy Management program areas. Allocation of funding is determined by several factors including initiatives and location of the position (i.e., whether in a shared service area or strictly natural gas, for example).

31.8 Please provide the seven municipalities which are participating in the Climate Action Partners program currently.

Response:

The seven municipalities currently participating in the Climate Action partners program are:

- City of Surrey;
- City of Victoria;
- District of Saanich;
- City of Kamloops;
- City of Kelowna;
- Regional District of Central Kootenay; and
- Regional District of Kootenay Boundary.

31.9 Please provide a detailed explanation for how the Climate Action Partners program operates, including, but not limited to, the following:

- How the application process works (i.e. how a municipality or other organization applies and gains access to the funding);
- The specific requirements and reporting processes, if any, the organization/municipality must follow and meet in order to retain the funding;
- Who the Senior Energy Specialist is employed by (i.e. FEI or the municipality/other organization);
- How the long the funding is provided for (i.e. is there a set number of years/time period?); and
- Who develops the "pre-defined work plan"?

Response:

Upon expressing an interest in the Climate Action Partners program, FortisBC and the potential host organization discuss the needs and priorities of that organization, as well as opportunities for participation in FortisBC's energy efficiency and conservation programs, and low carbon and renewable energy solutions. After discussing whether there may be a partnership fit, if both the organization and FortisBC are interested in pursuing a Senior Energy Specialist position, both work together to develop a joint work plan.

The work plan is "pre-defined" in the sense that it is established before the host organization hires the Senior Energy Specialist. The host organization typically makes a first draft of the work plan and then sends the work plan to FortisBC. Developing the work plan is an iterative process to ensure that the needs of both organizations are met; the work plan is ultimately approved by both the organization and FortisBC. The work plan is then included in the funding agreement, which is signed by both the host organization and FortisBC.

The standard Senior Energy Specialist funding agreement is for a duration of two years; however, funding may be provided for one year where the host organization requests a one year contract.

Also, in most cases the Senior Energy Specialist is employed by the host organization. However, in certain circumstances where the host organization preferred to use a FortisBC employee, a FortisBC employee has been employed as the Senior Energy Specialist for the host organization.

Specific program requirements and reporting processes include:

- Hiring a Senior Energy Specialist that meets the program requirements. Qualified candidates must hold a Bachelor's degree, a minimum of five years' experience working in a field related to energy or sustainability and must possess at least one of the following:
    - Graduate degree in public policy, sustainability, resource management, or a related business field;
    - Registered professional engineer;
    - Registered planner;
    - Sustainable Energy Management Associate (BC Institute of Technology);
    - Certified Energy Manager designation (Canadian Institute for Energy Training);
- Participating in monthly best practices/update calls led by the Program Manager, Climate Action Partners;
- Participating in training sessions. To date, these training sessions have been hosted bi-annually by FortisBC;
- Completing deliverables identified within the work plan for each year of the contract agreement; and
- Developing and delivering to FortisBC quarterly reports and a final report.

31.10 Please explain why providing funding for Senior Energy Specialist roles to other organizations is appropriately classified as FEI O&M.

Response:

Funding for Senior Energy Specialist roles, as part of the Climate Action Partners Program, is appropriately classified as FEI O&M as these positions support the use of FortisBC's energy solutions while helping local governments and other organizations meet their climate objectives. Increased engagement is a central part of FEI's response to addressing the challenges in its operating environment, including rapidly changing climate policy (please refer to the response to BCUC IR 1.1.1). Moreover, governments and other organizations in B.C. are developing climate plans and taking action to reduce their GHG emissions. Without FortisBC's active participation and engagement through the Senior Energy Specialist roles and the Climate Action Partners program more broadly, FEI's services are often not considered in climate plans and activities to shift the Province toward a lower carbon economy.

Accordingly, these roles are important for attracting and retaining customers for FEI's products and services and are therefore appropriately classified within FEI's O&M costs.

FEI also requests the following incremental funding related to the Climate Action Partners Program, as outlined in Table C2-11 on page C-34 of the Application:

- $0.180 million for "Expanding the program's partnerships with indigenous communities, non-profit and academic organizations"; and
- $0.250 million for "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)".

31.11 Please clearly differentiate between the incremental funding described in the above preamble and the incremental requested for the Connect to Gas program related to "Collaboration with Stakeholders," as described on page C-32 of the Application.

Response:

Incremental funding related to the Climate Action Partners program, as identified in the preamble, and the Connect to Gas program are separate requests as the target audience and objectives are different for each.

- Connect to Gas targets stakeholders such as builders, developers, engineers, architects, contractors and any other stakeholders that influence the connection to natural gas and using natural gas appliances.
- Climate Action Partners promotes FEI's lower carbon solutions to a broader audience including federal, provincial and local governments, as well as public sector organizations, Indigenous communities, non-profit organizations and academic organizations.

The Climate Action Partners incremental funding of $0.180 million is for expanding partnerships. The Climate Action Partners incremental funding request also includes $0.250 million for providing targeted support for stakeholders, which includes supporting climate workshops, investing in events to educate FEI's customers about available low carbon and renewable energy sources, and promoting dialogue on the role of the gas system in achieving the Province's CleanBC targets.

The Connect to Gas incremental funding of $0.250 million on page C-32 relates to targeted communication to a different group of stakeholders mentioned above to enable FEI to both grow and retain customers.

31.11.1 As part of the above response, please explain why it is reasonable to receive incremental funding of $0.250 million for "Collaboration with Stakeholders" activities under the Connect to Gas program and to receive incremental funding of $0.250 million for "Targeted support to stakeholders" under the Climate Action Partners Program.

Response:

Please refer to the response to BCUC IR 1.31.11.

31.12 Please provide a detailed breakdown and description of the planned spending of $0.180 million for "expanding the program's partnerships with indigenous communities, non-profit and academic organizations."

Response:

The Climate Action Partners program pursues partnerships with various stakeholders in order to educate on FortisBC's energy efficiency, conservation, low carbon and renewable energy offerings, and on the role of the gas delivery system in driving progress toward the Province's CleanBC targets. Planned spending on expanding the program's partnerships includes:

	Amount (millions)
Indigenous communities (e.g., Musqueam Indian Band)	$0.060
Non-profit & clean energy industry organizations (e.g., Community Energy Association, BC Bioenergy Network)	$0.060
Academia (e.g., UBC Okanagan Smart Energy Research Chair, SFU Renewable Cities)	$0.060
Total	$0.180

31.12.1 As part of the above response, please explain why the activities and spending related to indigenous communities would not be covered as part of the requested incremental spending of $0.200 million for "Indigenous Community Investments" described on page C-37 of the Application.

Response:

The $0.200 million for Indigenous Community Investments described on page C-37 of the Application is focused on building capacity, training, projects and community investment in the Indigenous communities in which FortisBC operates. This funding is a separate request in the Application that falls under FEI's Community Investment criteria.

In contrast, the $0.180 million for expanding Climate Action Partners program partnerships described on page C-35 provides support to a variety of stakeholder types. To the extent that any of this funding is provided to Indigenous communities, it would not fall under "Indigenous Community Investments" because this spending is specifically allocated for education, workshops, and event sponsorships to further educate, promote and implement FortisBC's energy solutions that address climate action.

31.13 Please provide a detailed breakdown and description of the planned spending of $0.250 million for "targeted support to stakeholders."

Response:

Please find below a breakdown of the planned spending for the targeted support to stakeholders:

	Amount (millions)
Research (e.g., Mitacs Accelerate power-to-gas system impacts, infrastructure requirements and policy implications)	$0.050
Focus Groups (e.g., Clean Energy Canada focus groups on framing communications of CleanBC transition)	$0.070
Workshops (e.g., Pembina dialogue on energy transitions)	$0.055

	Amount (millions)
Support for local governments (e.g,. Decarbonizing commercial transportation guide and engagement)	$0.030
Education (e.g., Energy Leaders program for schools (non-DSM))	$0.045
TOTAL	$0.250

On pages C-35 and C-36, FEI requests incremental funding of $0.160 million for "Web-Based Platforms Support" and states the following: "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."

On page C-32 of the Application, FEI states: "Additional in-house resources including a Digital Advisor and Communications Writer/Researcher are required to support these activities."

31.14 Please explain why FEI is requesting incremental funding of $0.160 million for a "Digital Communications Advisor" and incremental funding of $0.160 million for a "Digital Advisor and Communications Writer/Researcher".

Response:

These are two different funding requests, further described below.

The request for $0.160 million for "Web-Based Platforms Support" on page C-35 is to address the increased needs of the Talking Energy and Energy Leaders microsites and corresponding communications. The microsites have specific purposes and target specific audiences:

- Energy Leaders microsite informs teachers about energy efficiency and conservation lessons for the classrooms
- Talking Energy microsite informs customers, general public and local stakeholders about large scale infrastructure projects such as Tilbury expansion and Lower Mainland Intermediate Pressure System Upgrades

Below is a table to illustrate how the Digital Advisor would support the microsite/programs.

Description	Digital Advisor role
Talking Energy microsite	• Research and manage development of new web functions/widgets/tools/maps • Review analytics and seek insights and opportunities to improve/increase engagement
Talking Energy newsletter	• Manage email database • Set up analytic tracking for newsletter links • Test email layout on different device types
Talking Energy related social media posts	• Post social media content • Respond to comments • Review analytics • Seek opportunities to increase engagement on future posts
Talking Energy paid media campaign	• Review analytics and provide insights on campaign • Seek opportunities to increase engagement on future campaigns
Energy Leaders microsite	• Research and manage development of new web functions/widgets/tools • Review analytics and seek insights and opportunities to improve/increase engagement
Energy Leaders newsletter	• Manage email database • Set up analytic tracking for newsletter links • Test email layout on different device types
Energy Leaders related social media posts	• Post social media content • Respond to comments • Review analytics • Seek opportunities to increase engagement on future posts
Energy Leaders paid media campaign	• Review analytics and provide insights on campaign • Seek opportunities to increase engagement on future campaigns

The request for additional "In-house resources to address customer preferences" on page C-32, including a Digital Advisor and Writer/Researcher, is to support customer communication. The incremental requirement is to support the growing amount and types of communication channels, such as:

- Facebook (launched in 2018) – Provides a highly engaging platform for customers. Platform must be developed and maintained for customers to receive and share content, as well as customer inquiries through direct messaging;
- Twitter, LinkedIn and Instagram – Specific content needs to be developed for each as each have unique features within their channel and slightly different audiences, such that a 'one-size-fits-all' approach is not effective;
- E-Newsletters - Regularly scheduled e-newsletters to reach customers about specific projects, rebates and programs;

- Blogs - Relevant and timely blog like content on the websites to address customer inquiries/comments that FortisBC has seen through the various communication channels; and
- Customer bills - Develop content and test usability on bill redesign.

Below is a table to show how the additional Writer/Researcher and Digital Advisor roles would support customer communications needs.

Description	Writer/Researcher	Digital Advisor
Facebook	• Develop copy for organic and paid media campaigns to drive traffic back to fortisbc.com	• Post social media content • Respond to comments • Review analytics • Seek opportunities to increase engagement on future posts
Other social media channels (Twitter, LinkedIn, Instagram, and Youtube)	• Develop copy for organic and paid media campaigns to drive traffic to fortisbc.com	• Post social media content • Respond to comments • Review analytics • Seek opportunities to increase engagement on future posts • Provide recommendations on content types that best suit each channel
Regularly scheduled e-newsletters, such as Energy Moment	• Develop copy for newsletter, driving traffic back to fortisbc.com	• Manage email database • Set up analytic tracking for newsletter links • Test email layout on different device types
Blog like content/stories for fortisbc.com	• Research and develop timely and relevant blog content/stories for fortisbc.com	• Share on social media channels • Review analytics • Provide recommendations on future blog posts
Overall user experience for fortisbc.com	• Develop copy for customer testing	• Develop mockups and prototypes of new page layouts/functionality/widgets to continuously improve customers' online experience • Test for quality assurance
Overall search ability for FortisBC content	• Develop relevant and unique content for fortisbc.com	• Optimize content through search engine optimization
Customer bills	• Develop content for bill redesign to test with customers	• Provide usability recommendations for both print and digital versions

Please also refer to the response to BCUC IR 1.30.25 for further information as to how the roles and responsibilities for the writer/researcher and digital advisor positions differ.

31.14.1 As part of the above response, please clearly distinguish the roles and responsibilities between the two positions and explain why these roles and responsibilities cannot be performed by one person.

Response:

Please refer to the response to BCUC IR 1.30.25.

On page C-36 of the Application, FEI requests incremental funding of $0.200 million for "Program Development" and states that the "funding is required for early stage policy and program development including legal fees associated with regulatory developments."

31.15 Please specifically explain the purpose of the funding, including whether FEI intends to hire additional legal counsel, and why FEI's existing legal resources are not adequate to perform the "Program Development" activities.

Response:

There are many considerations pertaining to the federal and provincial government's policies that impact FEI's business such as future considerations of UNDRIP implementation, revised environmental assessment regulations and lobbying regulations. The additional funds allow for both investigation of considerations at the early stages of policy and regulatory development as well as seeking legal guidance on proposed rules and regulations. This includes examining the cost and energy system implications of policies to meet the Province's 2030 and 2050 emissions reduction goals. FEI's existing legal resources are not adequate to perform the program development activities in cases where FEI's legal team has determined there is a need to consult external legal counsel due to capacity constraints or in the case of new or developing policy areas.

32.0 Reference: FEI O&M BASE

Exhibit B-1, Section C2.4, pp. C-24 – C-42

New Funding for MRP Term – System Operations, Integrity and Security

On page C-37 of the Application, FEI provides the following table:

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

32.1 Please provide the department and account number (based on the account codes provided in the O&M activity view in Appendix A3-1 to the Application) which each of the costs provided in Table C2-13 were recorded in.

Response:

Please see below for the corresponding department and account number which each of the costs provided in Table C2-13 were recorded in:

Particulars	Department	Account Number	Account Description
System Operations, Integrity and Safety			
Integrity Management	Operations	120-21	Pipeline/Right Way of Operations
	Operations	120-31	Pipeline/Right Way-Maintenance
Maintaining System Infrastructure	Operations	110 and 120 account series	Various Distribution & Transmission accounts
Operations Compliance and Safety	Operations	110 and 120 account series	Various Distribution & Transmission accounts
Cyber Security	Information Systems	420-13	Infrastructure Management
Data Analytics [1]	not applicable		
Gas Control	Energy Supply & Resource Development	410-12	Gas Control
CEPA Participation [1]	not applicable		

[1] Not applicable as the costs were not yet incurred and therefore not included in Appendix A3-1

32.2 Please provide a detailed breakdown and description of the annual actual and formula amounts for each line item in Table C2-13 for the years' 2014 through 2018.

Response:

Under the Current PBR Plan, FEI's formula O&M spending is determined at the aggregate level. FEI does not have disaggregated formula amounts for O&M by line item. As a result, FEI is unable to provide formula amounts for each line item.

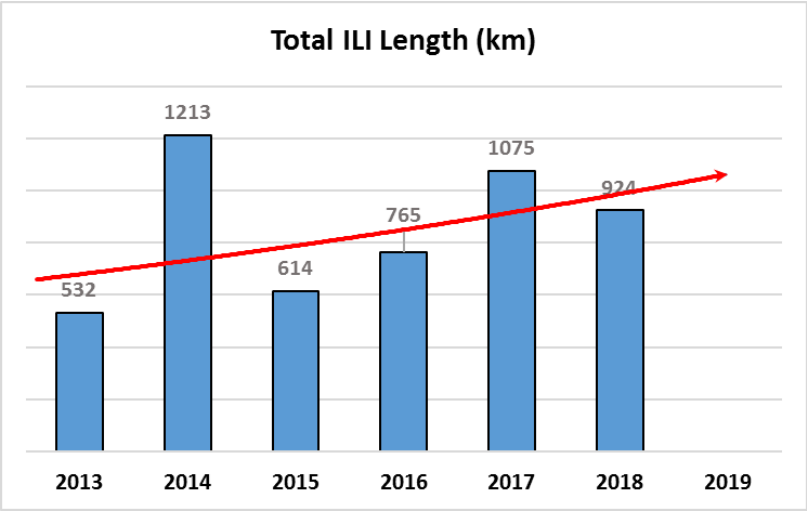
Following are details and discussion of the actual expenditures for each of the line items separated into labour and non-labour during the years 2014 through 2018.

System Operations, Integrity and Safety

Expenditures for Integrity Management, Maintaining System Infrastructure, and Operations Compliance and Safety activities have steadily increased from 2014 through 2018.

For Integrity Management, expenditures are increasing as FEI works to improve the Integrity Management Program and accommodate the additional scope to keep up with evolving requirements. The Integrity Management scope includes management of the Integrity Management Program (IMP), in-line inspection data analysis, natural hazards monitoring and corrective work, and cathodic protection.

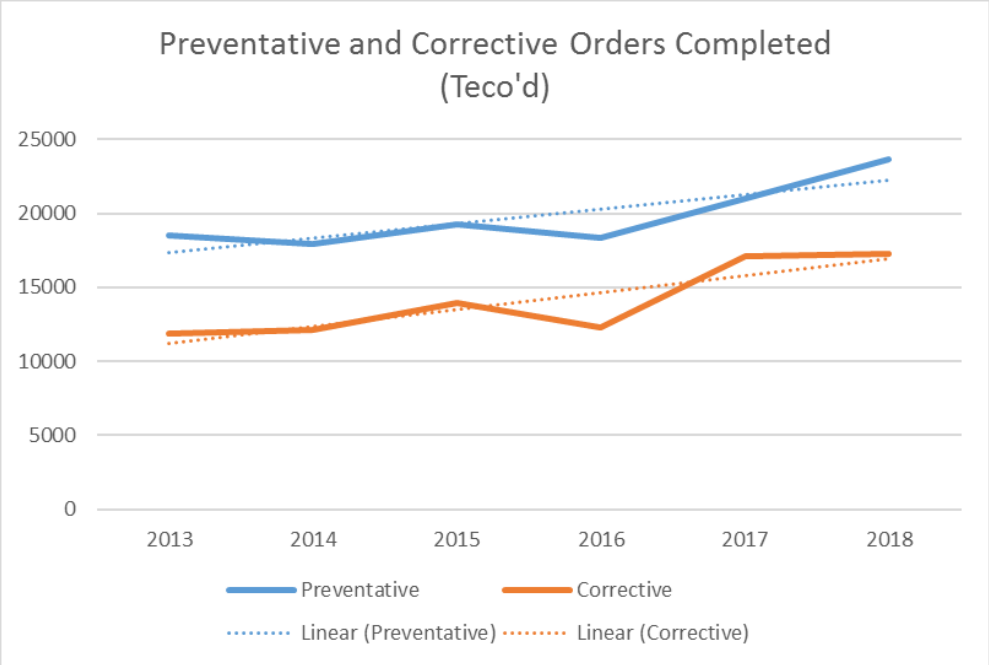
As illustrated in the following graph, the number of kilometers of In-Line Inspection (ILI) performed each year since 2013 has increased along with the work to plan and prepare for integrity related digs. The annual ILI program will vary from year to year as illustrated in the following graph. The overall trend shows an increase over the past years.



In addition to increased ILI, FEI has performed record number of integrity related digs that require Integrity Management oversight. A detailed breakdown of the historical expenditures for Integrity Management (excluding the expenditures for Integrity Digs) is provided in the table below:

Integrity Management	Historical Expenditures ($ millions)				
	2014	2015	2016	2017	2018
Labour	0.800	1.000	0.900	0.900	0.900
Non-Labour	0.600	0.500	0.600	0.700	0.900
Integrity Management Program (IMP) Total	1.400	1.500	1.500	1.600	1.800
Labour	0.400	0.500	0.600	0.600	0.800
Non-Labour	0.100	0.100	0.200	0.300	0.300
In-line Inspection Data Analysis Total	0.500	0.600	0.800	0.900	1.100
Labour	0.100	0.200	0.200	0.200	0.200
Non-Labour	0.800	0.800	1.100	1.300	1.300
Natural Hazards Monitoring and Corrective Work Total	0.900	1.000	1.300	1.500	1.500
Labour	0.100	0.200	0.200	0.200	0.200
Non-Labour	0.600	0.700	1.100	0.800	0.700
Cathodic Protection Total	0.700	0.900	1.300	1.000	0.900
Total	3.500	4.000	4.900	5.000	5.300

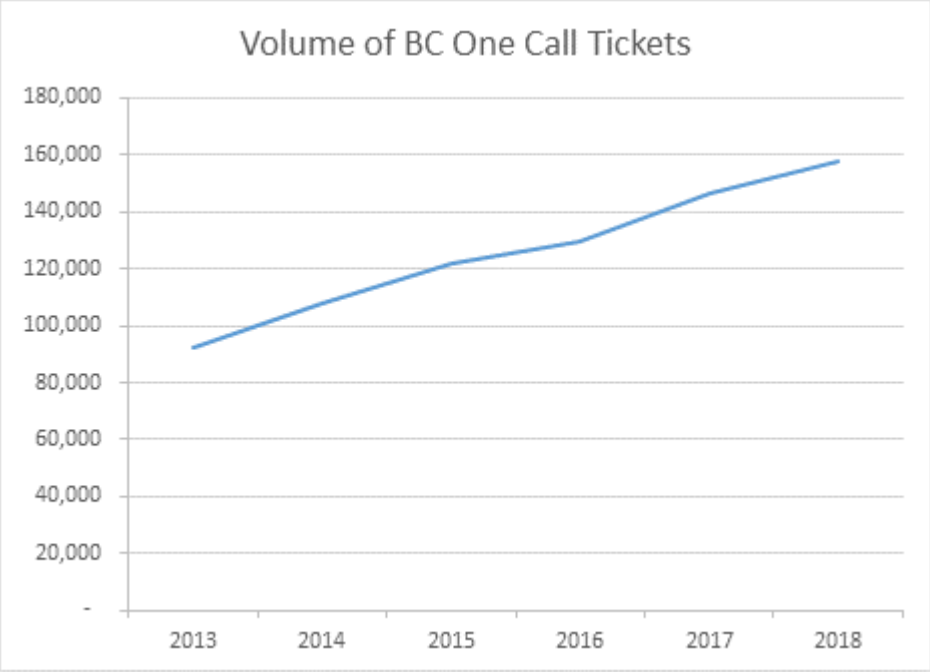
For Maintaining System Infrastructure, expenditures are increasing as FEI is adding new assets and maintaining aging infrastructure. The Maintaining System Infrastructure scope includes corrective maintenance and preventative maintenance costs. Corrective maintenance are the activities to fix assets and preventative maintenance are the activities to prevent assets from breaking down. Equipment and systems are more complex and need more site or asset-specific maintenance planning and execution. Existing infrastructure is aging and requires more frequent maintenance to extend its life, and minimize life cycle costs. Both preventative and corrective work activities have increased from 2013 to 2018, by 28 percent and 46 percent respectively. The following figure shows the preventative and corrective work trend.



A detailed breakdown of the historical expenditures is provided in the table below:

Maintaining System Infrastructure	Historical Expenditures ($ millions)				
	2014	2015	2016	2017	2018
Labour	4.300	5.400	5.200	5.300	5.500
Non-Labour	4.100	7.400	4.300	4.100	4.700
Corrective Maintenance Total	8.400	12.800	9.500	9.400	10.200
Labour	13.900	12.200	13.200	12.900	15.400
Non-Labour	16.500	13.900	17.800	18.400	17.600
Preventative Maintenance Total	30.400	26.100	31.000	31.300	33.000
Total	$ 38.800	$ 38.900	$ 40.500	$ 40.700	$ 43.200

For Operations Compliance and Safety, expenditures are increasing as FEI works to meet codes, regulations, FEI standards and industry practices. The Operations Compliance and Safety scope includes the meter recall and exchange program, emergency response, competency and training, Safety, ROW management, and BC One Call response. BC One Call tickets and third-party activities around our pipelines and Transmission Line ROW are all increasing. Since 2013, the BC One Call ticket volume has increased by 70 percent. The following figure shows this trend.



FEI is also seeing increases in third party activities around assets and transmission line right of ways as described in the response to BCUC IR 1.4.1. A detailed breakdown of the historical expenditures is as follows:

Operations Compliance and Safety	Historical Expenditures ($ millions)				
	2014	2015	2016	2017	2018
Labour	2.460	2.900	2.467	2.600	3.325
Non-Labour	2.790	2.630	3.880	3.596	2.399
Meter Recall and Exchange Program	5.250	5.530	6.347	6.196	5.724
Labour	4.270	5.300	5.100	5.332	5.111
Non-Labour	0.962	0.624	0.685	0.758	0.776
Emergency Response	5.232	5.924	5.785	6.090	5.887
Labour	1.873	1.333	2.008	1.949	2.558
Non-Labour	0.480	0.340	0.460	0.475	0.691
Competency and Training	2.353	1.673	2.468	2.424	3.249
Labour	0.763	0.680	1.052	0.997	1.062
Non-Labour	0.167	0.250	0.276	0.234	0.367
Safety	0.930	0.930	1.328	1.231	1.429
Labour		0.175	0.207	0.245	0.383
Non-Labour		0.040	0.058	0.072	0.134
ROW Management	-	0.215	0.265	0.317	0.517
Labour	1.890	2.524	2.590	2.530	2.391
Non-Labour	0.040	0.300	0.240	0.414	0.306
BC One Call Response	1.930	2.824	2.830	2.944	2.697
Total	$ 15.700	$ 17.100	$ 19.000	$ 19.200	$ 19.500

Cyber Security

In 2018, total expenditures were approximately $670 thousand, comprised of $154 thousand for labour expense, with the remaining $516 thousand for non-labour (consulting, software, employee expense).

FortisBC had a successful year in 2018 in terms of cybersecurity. FortisBC was able to leverage external resources to firm up the cybersecurity resources as a whole, taking into account the corporate IS cybersecurity position as well as operations. Assessments were completed for a managed security provider, which will add to FortisBC's internal resource capability. Training and awareness were brought to the forefront for FortisBC employees reducing the risk of vulnerabilities caused by phishing.

FortisBC was able to respond to cybersecurity threats and prevent potential material incidents.

Gas Control

Provided below are details of the expenditures, separated into labour and non-labour.

	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals
Total Labour	**1,507**	**1,676**	**1,775**	**1,748**	**1,906**
Total Non-Labour	**179**	**437**	**460**	**408**	**300**
TOTAL O&M	**1,686**	**2,113**	**2,235**	**2,156**	**2,206**

From 2014 to 2018, expenditures have been relatively stable with fluctuations from year to year due in part to the timing of expenditures. Staffing costs have varied due to permanent and temporary staffing changes. Non-labour expenditures include that for computer support for SCADA and communication costs. In 2015, costs increased by approximately $225 thousand due partially to the elimination of management services fees for services provided to FEVI resulting from the amalgamation of FEI and FEVI/FEW. FEVI had previously accounted for the costs as part of their gas costs. A SCADA support position was also added during the year.

Recently, in 2018, labour costs increased due to the addition of a Gas Control Supervisor position, required to support increasingly complex gas control operations. Non-labour expenditures decreased due to temporary savings on computer support expenditures as the SCADA platform is scheduled to be replaced in 2019/2020.

On page C-38 of the Application, FEI states the following:

FEI needs to continue to improve its [Integrity Management Program] 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.

32.3 Please explain if FEI has any areas of non-conformance, or anticipates any areas of non-conformance, with CSA Z662-15 and if so, please provide details of the non-conformances and FEI's proposed strategies for attaining compliance.

Response:

FEI is compliant with the CSA Z662-15 requirements (as adopted by the BC OGC); however, the BC OGC has directed FEI to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC. FEI is responding to the pipeline risk assessment direction by completing a quantitative risk assessment of its transmission pipelines.

FEI also has a number of findings identified by the BC OGC in response to an Industry Bulletin "New Requirements for Integrity Management Programs for Facilities", as discussed in response to BCUC IR 1.28.8.

Continual improvement is a fundamental component of well-developed, standards-based management systems, examples of which include ISO 9001, ISO 14001, and CSA Z662-15 Clause 3. Further, FEI is obligated by Clause 3.1.2(h) of CSA Z662 to include a process for continual improvement within its Integrity Management Program. FEI also considers it necessary to continually improve its practices in alignment with industry practice. As such, continual improvements are an expected part of FEI's ongoing integrity management activities and there are provisions within FEI's integrity management program, including periodic management reviews and internal audits, to ensure the requirement to continually improve is met.

FEI's management systems have been developed to ensure FEI's ongoing compliance to regulations, and FEI does not anticipate becoming non-compliant. However, FEI does anticipate that continual improvements will continue to be identified and undertaken by FEI on an ongoing basis.

32.3.1 If FEI does not have any areas of non-conformance (or anticipated areas), please discuss the need to improve FEI's Integrity Management Program (IMP). In your response please discuss the applicable CSA Z662-15 requirements.

Response:

Please refer to the response to BCUC IR 1.32.3.

32.4 Please provide details of FEI's risk assessment for time-dependent failure mechanisms and identify the proposed mitigation strategies.

Response:

There is an increasing risk of time-dependent failure mechanisms due to the fact that FEI's pipelines are aging and the probability of failure for time-dependent failure mechanisms increases with time. FEI is undertaking its first iteration of a quantitative risk assessment as part of the development of its Transmission Integrity Management Capabilities (TIMC) project.

FEI's current activities for managing time-dependent failure mechanisms, as included within its Integrity Management Program for Pipelines, are as follows:

- Cathodic protection system management (which includes monitoring and mitigation);
- Modified External Corrosion Direct Assessment (which includes above-ground surveys and integrity digs);
- In-line inspection (which includes in-line inspection tool runs, analysis, and integrity digs); and
- Screening for stress corrosion cracking during integrity digs.

32.5 Please discuss whether FEI has experienced any pipeline failures due to time-dependent threats such as corrosion. If so, please provide details of any incidents.

Response:

The following table provides details of FEI's recorded transmission pipeline failures due to time-dependent threats. All failures were leaks, with the exception of one rupture attributed to corrosion in combination with slope movement (i.e., interacting hazards) on the Oliver Grand Forks 273 pipeline.

Pipeline Name	Failure Year	Failure Type
Chase Lateral 88	1992	Leak
Fernie Lateral 88	2004	Leak
Fording Lateral 219	1996	Leak
Galloway Lateral 60	2000	Leak
Grand Forks Trail 273	1968	Leak
	1979	Leak
	1985	Leak
Livingston Pattullo 457	1996	Leak
Oliver Grand Forks 273	1966	Leak
	1969	Leak
	1973	Leak
	1973	Leak
	1973	Leak
	1973	Leak
	1975	Leak
	1980	Leak
	1984	Leak
	1984	Leak
	1984	Leak
	1984	Leak
	1984	Rupture
	1993	Leak
	1993	Leak
	2001	Leak
Savona Vernon 273	1984	Leak
	1984	Leak
Trail Castlegar 219	1975	Leak
	1980	Leak
	1983	Leak
	2004	Leak

FEI further states on page C-38 of the Application:

> 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.

On page C-23, FEI states the following:

> 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.

FEI provides the following table on page C-23 of the Application:

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%**

32.6 Please update Table C2-3 to provide a comparison of the Number of Digs per Year and the actual expenditures for each Reason for Dig category for years 2011 through 2018. Please include a comparison of the unit cost per Integrity Dig.

Response:

FEI has expanded the existing data fields in Table C2-3 to provide the actual annual expenditures and an average unit cost per integrity dig.

Reason for digs	Number of Digs per Year								
	2011	2012	2013	2014	2015	2016	2017	2018	2019 YEF
Dent digs (includes dig selections that were influenced by the strain-based criteria)	0	6	26*	12	11*	30*	21	15	30
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	27	20	10*	44	36*	10
Other ILI digs	45	24	20*	19	33*	34*	25	34*	45
Non-ILI digs	9	8	4	4	2	0	8	1	5
Total Integrity Digs	**54**	**38**	**50***	**62**	**66***	**74***	**98**	**86***	**90**
Total Expenditures ($000's)	$1,600	$1,800	$1,400	$2,300	$2,300	$2,500	$3,200	$2,500	$3,100+
Cost per dig ($000's)	$30	$47	$28	$37	$35	$34	$33	$29	$34+

* *Note: Variances in dig numbers from past reporting has resulted from ongoing efforts in collecting and verifying historical dig data.*

+ *The 2019 YEF is subject to change based on field conditions and necessary repairs. FEI notes that dig scope and costs can vary significantly.*

Please also refer to Attachment 27.3 provided in the response to BCUC IR 1.27.3 for a copy of FEI's response to BCUC IR 1.8.1.2 in the FEI IGU CPCN Application proceeding, which contains recorded site-specific integrity dig costs for 2015, 2016, 2017 and 2018.

32.6.1 Please also provide the formula amounts and the forecast number of integrity digs for each of the year's 2014 through 2019.

Response:

Under the Current PBR Plan, FEI's formula O&M expense is determined at the aggregate level. FEI does not have disaggregated formula amounts by department or activity. FEI also does not have a historical forecast number of integrity digs for each of the years 2014 through 2019. FEI determines its annual integrity dig requirements as new ILI and other information becomes available.

32.7 Please explain the increase in the number of Integrity Digs between 2016 and 2017. In your response please discuss whether FEI implemented an increased number of in-line inspections during the period.

Response:

The number of integrity digs increased between 2016 and 2017 primarily due to an increase in the number of circumferential magnetic flux leakage (CMFL) in-line inspection (ILI) driven digs. The increase did not directly result from an increased number of ILI during the period. Please refer to the response to BCUC IR 1.32.8 for analysis on the correlation between the number of in-line inspections, the length of pipe inspected (km) and the number of Integrity Digs from the period 2011 to 2018. The response also contains a list of contributing factors as to why a correlation is not expected.

Both 2016 and 2017 CMFL ILI driven digs were based on prior years' CMFL ILI runs, which had been re-analyzed to validate the ILI tool. Tool validation digs provide data to FEI's assessment of tool performance, including the potential for tool reporting bias (i.e., tool uncertainty).

32.8 Please provide analysis on the correlation between the number of in-line inspections, the length of pipe inspected (km) and the number of Integrity Digs from the period 2011 to 2018.

Response:

FEI does not believe that the 2011 to 2018 data demonstrates a meaningful correlation between the number of in-line inspections, the length of pipe inspected (km), and the number of annual Integrity Digs. For the purposes of this analysis, FEI separated in-line inspection driven integrity digs as described in the table below, and provided a graph showing the number of in-line inspections and the number of Integrity Digs (Figure 1). FEI also provides a graph showing the kilometres of in-line inspections in conjunction with number of integrity digs (Figure 2):

Table 1: Summary of Number of In-line Inspection, Length of Pipe Inspected, and Number of Integrity Digs from 2011 to 2018

Year	Number of In-line Inspection	Length of Pipe Inspected (km)	Number of Integrity Digs+
2011	9	142	45
2012	9	568	30

Year	Number of In-line Inspection	Length of Pipe Inspected (km)	Number of Integrity Digs+
2013	16	708	46*
2014	12	1202	58
2015	7	396	64*
2016	11	478	74*
2017	13	704	90
2018	15	588	85*

+ *Only ILI driven integrity digs.*

* *Note: Variance in dig numbers from past reporting has resulted from ongoing efforts in collecting and verifying historical dig data. Please refer to BCUC IR 1.32.6 for complete year-to-year dig numbers.*

Figure 1: Number of In-line Inspections in conjunction with Number of Integrity Digs, 2011 to 2018

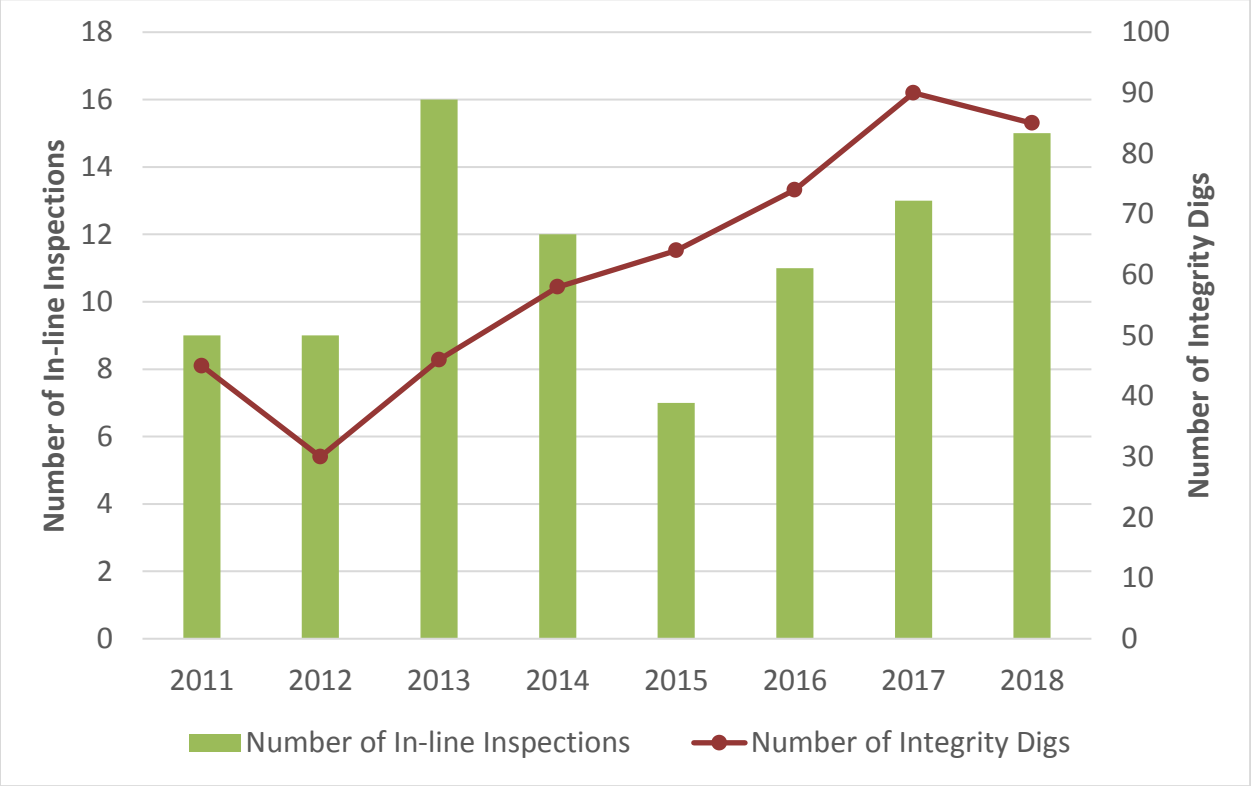
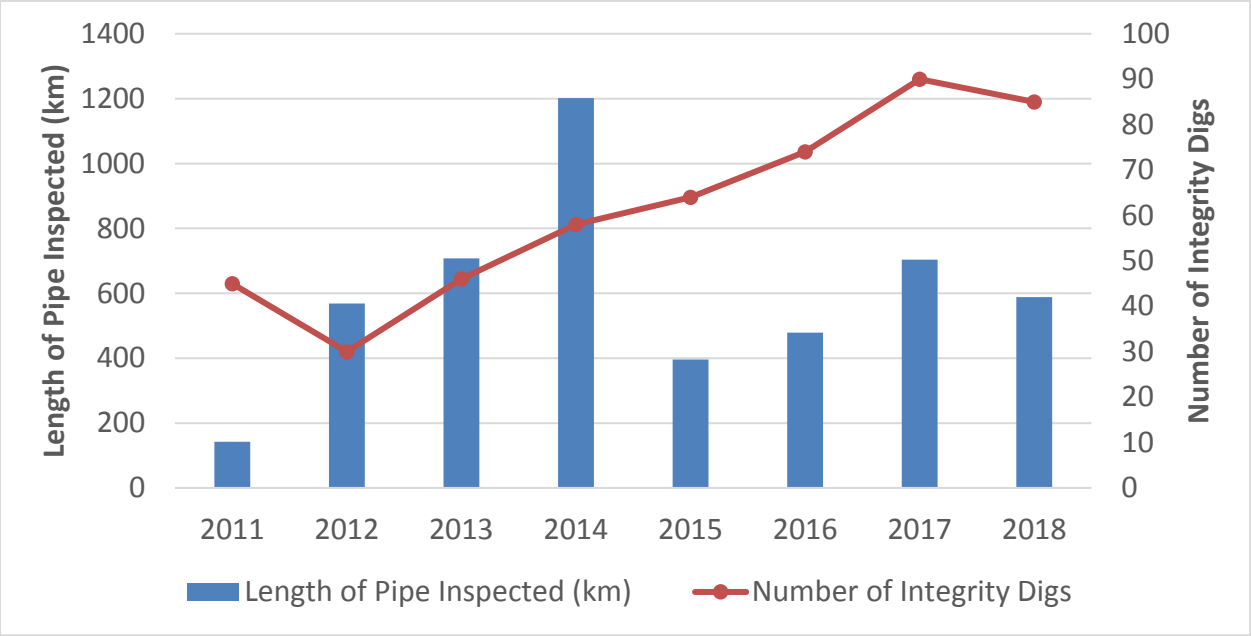


Figure 2: Kilometres of In-line Inspections in conjunction with Number of Integrity Digs, 2011 to 2018



The number of in-line inspections, the length of pipe inspected (km), and the number of annual integrity digs do not correlate for the following reasons:

- The length of in-line inspected pipelines varies from approximately 2 km to 165 km. As such, the use of the number of in-line inspections, in isolation, does not provide an accurate indication of the quantity of in-line inspection data to be reviewed, as well as the potential quantity of integrity digs.
- FEI's pipelines are not in equivalent condition; therefore, the density of integrity digs (i.e., digs per km) required on some pipelines is higher than for others.
- In-line inspection tool runs do not necessarily produce data of equivalent quality (e.g., speed excursions or pipeline contaminants during tool runs can reduce data quality and completeness); therefore, the quantity of tool validation digs or other digs (i.e., required to address uncertainty in ILI data) required for some ILI runs will be higher than for others. This is true for all ILI tool runs, including tool runs on the same pipeline with the same technology.
- In-line inspection tool capabilities (e.g., detection threshold and sizing accuracy) evolve with time; therefore, subsequent inspections with the same tool technology can result in substantially different numbers of Integrity Digs.
- FEI re-evaluation of ILI tool-reported data in the years between successive in-line inspections (i.e., incorporation of integrity dig findings) can result in a significantly higher

number of digs than was determined in the original evaluation. Therefore, digs on a given pipeline can be determined in any year between successive in-line inspections and do not necessarily occur in the first or second year after a tool run.

- Assessment criteria can change over time, as illustrated by the strain based dent criteria applied by FEI since 2013 (refer to Attachment 32.8 for a copy of FEI's response to FEI Annual Review for 2018 Rates, BCUC IR 1.1.7). This can have a considerable impact on the quantity of integrity digs required for a single ILI tool run. Criteria can change at any time and therefore the number of digs resulting from such a change can occur in any year between successive in-line inspections.

32.9 Please provide the forecast for number of Integrity Digs and associated expenditures for the Proposed MRP period according to the Reason for Dig categories listed in Table C2-3. Please provide the forecast for the following scenarios:

- Number of Integrity Digs if FEI's CPCN applications for the Inland Gas Upgrades (IGU) and Transmission Integrity Management Capabilities (TIMC) projects are approved; and
- Number of Integrity Digs if FEI's CPCN applications for the Inland Gas Upgrades (IGU) and Transmission Integrity Management Capabilities (TIMC) projects are not approved.

Response:

Given the degree of uncertainty in required dig numbers from year to year, FEI does not typically undertake the development of integrity dig forecasts. As included in the response to BCUC IR 1.32.6.1, FEI determines its annual integrity dig requirements as new ILI and other information becomes available. Please refer to the excerpt below from FEI's response to BCUC IR 2.42.3 in the FEI IGU CPCN Application proceeding for a description of FEI's considerations in establishing the required integrity digs each year:

42.0 Reference: PROJECT DESCRIPTION

Exhibit B-2, BCUC 1.8.1, pp. 31 to 62, BCUC 1.12.5.2, p.107

List of Integrity Digs Conducted by FEI

In response to BCUC 1.8.1, FEI provide tables of recorded in-line inspection or Modified ECDA driven integrity digs conducted by FEI on transmission pipelines from 2000 through 2018.

In response to BCUC 1.12.5.2, FEI states:

> The number of digs conducted annually is established based on consideration of many factors, including resource availability. In past years, FEI has prioritized known corrosion locations (i.e. integrity digs identified through in-line inspection) over potential corrosion locations as indicated by above-ground surveys.

42.3 Please elaborate on the factors FEI considers in establishing the number of digs conducted annually.

Response:

When establishing the number of digs conducted annually, FEI considers the following technical factors:

- FEI's assessment of in-line inspection tool-reported data relative to CSA Z662-15 Clause 10.10 defect assessment criteria.
    - When FEI has specific knowledge of tool-reported features that may require repair in accordance with CSA Z662-15 criteria, FEI often considers this as reliable information warranting prioritized action, dependent on tool uncertainty.
- FEI's assessment of the potential for future rupture or leak from ILI tool-reported data.
    - When FEI's analysis demonstrates the potential for future failure of an ILI tool-reported feature, FEI often considers this as reliable information warranting prioritized action, dependent on tool uncertainty and analysis uncertainty, e.g., corrosion growth estimates.
- FEI's assessment of the need for ILI tool validation digs.
    - FEI requires dig data to assess tool performance, including the potential for tool reporting bias (i.e., tool uncertainty). The relative importance of this information to FEI's ILI analysis can vary depending on the pipeline and the particular tool run. FEI's professional judgement determines the necessity and priority of tool validation digs.
- Modified ECDA dig priority ranking (refer to the response to BCUC IR 1.12.5.2).
    - The Modified ECDA dig priority rankings (i.e., high and medium priority) are terms used within the Modified ECDA process to indicate a priority relative to other Modified ECDA indications. They are not indicative of an overall priority outside of the Modified ECDA process.

- Modified ECDA survey indications identify potential corrosion locations based on inferences from above-ground survey results, which themselves are based on cathodic protection system performance and coating quality of the buried pipeline.
- FEI has reduced confidence in Modified ECDA digs as Modified ECDA above ground survey methods cannot detect areas where CP shielding is occurring.
- As Modified ECDA is a process based on inferences and is limited by the presence of CP shielding on FEI's system, FEI has given lower priority to Modified ECDA excavations relative to in-line inspection-driven digs.

- Modified ECDA random control digs.
  - Random control digs do not provide FEI confidence that external corrosion features or other integrity issues are present on pipelines. This is because the location of random control digs is randomly selected, and not targeted to a specific site for the purposes of addressing any particular integrity concern. A random control dig provides information on a small segment of a much longer pipeline and therefore provides no statistically significant information on the condition of the pipeline as a whole, because the factors that affect pipeline condition vary from segment to segment across the length of the pipeline.
  - FEI has not prioritized Modified ECDA random control digs.
- All other available and relevant technical information.
  - All available and relevant technical information, including observations of potential hazards from sources supplementary to ILI and Modified ECDA (e.g. unauthorized external loading above a pipeline, visual observation of ground movement), must also be considered in FEI's determination of the number of digs conducted annually.

Non-technical factors such as resource availability, landowner impact, and cost effectiveness are also necessary considerations in FEI's determination of the number of digs conducted annually. As an example, advancing future excavations to the current year can, in some instances, provide an opportunity to reduce excavations occurring in successive years on a single landowner's property. It is typically more cost effective to complete multiple digs on a single crew mobilization to a particular area.

As stated in Section C2.4.2.2.3 of the Application, 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. Due to the uncertainty associated with integrity dig requirements when performing ILI in a pipeline for the first time, or when running a new ILI technology for the first time, FEI does not have any reasonable basis to project dig estimates to any defined level of certainty.

For the reasons above, FEI does not believe it is practical to undertake a dig forecast with a degree of accuracy that would provide meaningful value and as such is unable to provide the requested forecasts.

32.10 Please confirm, or otherwise explain, whether the Historical Expenditures provided in Table C2-13 includes the actual Integrity Digs expenditures for 2014 to 2018.

Response:

The expenditures in Table C2-13 do not include the actual Integrity Dig expenditures. As noted on page C-38 of the Application, FEI proposes to treat the costs of all integrity digs as a flow through item, outside of formula O&M as discussed above in Section C2.4.2.2.3.

Table C2-13 shows incremental items within the Base O&M, and excludes any items subject to flow-through treatment.

33.0 Reference: FEI O&M BASE

Exhibit B-1, Section C2.4.2, pp. C-41 – C-42

Gas Control

On page C-41 of the Application FEI states that "[i]ncremental funding for four additional gas controller positions will allow FEI to provide two-person Gas Control room coverage on a 24/7 basis."

FEI further states the following on page C-42 of the Application:

> 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.

33.1 Please provide details of any codes or standards that include requirements for gas control staffing levels. Please include details of on any relevant requirements.

Response:

Currently, there are no existing codes or standards that enforce control room staffing levels in Canada. However the U.S. Control Room Management Regulation, developed by the Pipeline & Hazardous Materials Safety Administration (PHMSA) that regulates liquid and gas pipeline operators in the U.S., stipulates adequate operator coverage to safely address and respond to alarms. Under the U.S. Control Room Management Regulation, staffing levels are determined by the number of alarms received, measured against operationally-established thresholds that determine how many alarms can be safely addressed on an hourly basis.

The Canadian Energy Pipelines Association (CEPA), which FEI has recently joined as a member, stipulates that a set of requirements similar to those under the U.S. Control Room Management Regulation be met. Incremental funding directly related to and driven by FEI becoming a CEPA member is captured at the "CEPA Participation" line in Table C2-13 of the Application. FEI believes increasing its Gas Control Room staffing to 12 Gas Controllers will allow FEI to comply with CEPA's requirements. However, as a new member, FEI is subject to an upcoming CEPA membership review process specifically focussed on Control Room Management. Irrespective of FEI becoming a CEPA member, the additional gas controller

positions proposed within this Application are 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 within a progressively complex and demanding operational environment. The operational complexity of the FEI system has increased over time. Factors including FEI's integrity program, aging assets, increasingly widespread use of telemetry, new field technologies, compliance requirements, and onboarding of large-scale customer loads that require unparalleled scrutiny on an ongoing basis all contribute to the increased gas controller workload.

33.2 Please provide details on the number of gas controller staffing levels that are being implemented by the regional industry peers referenced on page C-42 of the Application.

Response:

Information on the number of gas controllers of various companies is not publically available. FEI has obtained some information through confidential discussions with various regional local distribution companies (LDCs) and regional transmission pipeline companies, and has summarized its findings below.

Three of the main regional LDC entities that are comparable to FEI in customer-base size and system complexity currently operate with control room staffing that ranges between approximately 12 to 20 gas controllers to ensure adequate coverage.

As a secondary reference, control room staffing levels at regional transmission pipeline companies range from approximately 8 to 12 gas controllers, depending on the size of each operator's system complexity. Transmission pipeline operations typically focus on a single pipeline system that contains compression and/or storage, whereas typical LDC operations respond to a wide array of alarms covering the distribution grids.

FEI operates in both spaces, responding to alarms in distribution grids as well as operating pipelines that function as transmission pipelines.

The proposed increased staffing will bring FEI's Gas Control Room coverage up to 12 Gas Controllers, which will allow FEI to have two Gas Controllers on the board at all times, on a 24/7 basis.

33.3 Please discuss whether four additional gas controller positions is sufficient to ensure that FEI is able to meet the requirements of its customers, align with industry standards, and continue to operate in a safe and reliable manner.

Response:

FEI believes the incremental funding proposed at the "Gas Control" line in Table C2-13 which includes four additional gas controller positions, but excludes the additional gas control resources captured at the "CEPA Participation" line in Table C2-13 which are directly related to and driven by FEI becoming a CEPA member, are sufficient to allow FEI to meet the requirements of its customers, align with industry standards, and continue to operate in a safe a reliable manner based on the current, and short-term foreseeable, complexity of the FEI system.

FEI notes that various factors could affect the size and complexity of the FEI system and consequently its control room requirements in the future.

34.0 Reference: COMPONENTS OF THE PROPOSED RATE PLAN

Exhibit B-1, Section C2.5, pp. C-43 – C-48

FBC O&M Base and Formula

FBC provides the following table on page C-44 of the Application:

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

Footnote 131 on page C-44 of the Application states: "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)."

34.1 Please confirm, or explain otherwise, that the items included as part of the "Adjusted 2018 Base O&M" amount of $55.044 million in Table C2-14 (i.e. 2018 actual Base O&M, temporary savings, and Corporate/Shared Services Studies Impact) are intended to reflect 2018 amounts.

Response

FBC has reviewed Table C2-14 to check that all of the figures have been properly inflated to 2019 dollars, and provides below a revised Table C2-14 incorporating all of the corrections and which will be included in an Errata to be filed in the near future. The difference is a decrease in 2019 Base O&M of $0.016 million. Each of the items is discussed separately below.

Revised Table C2-14: FEI 2019 Base O&M ($millions)

2018 actual Base O&M	$ 53.839
Add temporary savings	0.500
Shared Services Studies Impact	0.338
Deduct 2018 actual FHI services direct charged to FBC	(1.023)
Deduct 2018 actual FI services direct charged to FBC	(1.615)
Adjusted 2018 Base O&M	$ 52.039
2019 Inflator	1.02382
2019 Base O&M before adjustments	$ 53.279
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	(0.237)
2019 Normalized Forecast FHI Management Fee	3.374
FBC Costs included in FHI Corporate Services	(0.308)
Total adjustments	3.628
New funding for MRP term	$ 0.763
2019 Base O&M	$ 57.670

Add temporary savings:

This amount is correctly stated in 2018 dollars.

Corporate/Shared Services Studies Impact:

The $0.705 million adjustment for Corporate/Shared Services Studies was comprised of two amounts – $0.338 million for Shared Services and $0.370 million for Corporate Services. These two items are now separated in the table above due to their different treatments; the Shared Services Study amount remains unchanged as it is based on 2018 actual expenditures as described in Appendix D-4 FEI and FBC Shared Service Study.

For the Corporate Services study impact, the adjustment requires revision as it was not intended to only reflect the 2018 impact from the Corporate Services study impact, but also to take into account the forecasted effect of the study in 2019 Base O&M for the term of the MRP. The revisions shown above (lines titled Deduct 2018 actual FHI services direct charged to FBC,

Deduct 2018 actual FI services direct charged to FBC, 2019 Normalized Forecast FHI Management Fee and FBC Costs included in FHI Corporate Services) are discussed further in the response to BCUC IR 1.147.1.

2019 Z Factors:

Correctly stated in 2019 dollars.

Manual meter read:

Correctly stated in 2019 dollars.

AMI Project cost reductions:

Correctly stated in 2019 dollars.

BCUC Levies:

The ($0.231) million has been changed to ($0.237) million to include the 2019 inflator adjustment.

34.2 Please confirm, or explain otherwise, that the items included under the "Adjustments" section of Table C2-14 (i.e. Exogenous Factors, Deferrals, and Flow Through treatment) are intended to reflect 2019 amounts.

Response:

Confirmed.

34.3 Given the statement in Footnote 131 that the corporate/shared services impact is comprised of the 2019 amounts, please clarify if the adjustment should instead reflect the Actual 2018 amount, or, alternatively, if the adjustment for the 2019 amount should instead be included as part of the "Adjustments" sections of Table C2-14. Specifically, please clarify if the 2019 inflator has been incorrectly applied to the corporate/shared services studies impact.

Response:

Please refer to the responses to BCUC IRs 1.34.1 and 1.147.1.

On page C-46 of the Application, FBC states that the actual 2018 BCUC levies amount of $0.231 million will be removed from Base O&M.

34.4 Please explain why the $0.231 million, which represents the 2018 BCUC levies amount, was not included as an adjustment to the "Adjusted 2018 Base O&M" prior to applying the 2019 inflator adjustment to 2019 Base O&M (i.e. similar to how the temporary savings adjustment was treated).

Response:

Please refer to the response to BCUC IR 1.34.1.

On page C-46 of the Application, FBC states: "As the AMI project is now complete, the ongoing savings of $1.161 million have been incorporated into the Base O&M."

34.5 Please confirm, or explain otherwise, that the $1.161 million represents the Actual 2018 AMI savings multiplied by the 2019 inflator of 1.02382.

Response:

Not confirmed.

The $1.161 million represents the projected 2019 AMI savings as indicated in the FBC Annual Review for 2019 Rates application, page 46:

> Table 6-5 below compares 2014 through 2019 net AMI savings to the net savings forecast in the AMI CPCN application.

Table 6-5: AMI Costs and Savings ($ millions)

Line No.		2014-2017			2018			2019	
1		Actual	Approved	CPCN[1]	Projected	Approved	CPCN[1]	Forecast	CPCN[1]
2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3									
4	AMI Costs	$ 5.202	$ 5.814	$ 6.792	$ 2.015	$ 2.015	$ 1.960	$ 2.055	$ 1.951
5	AMI Savings	(7.137)	(7.688)	(10.439)	(3.153)	(3.153)	(4.424)	(3.216)	(4.244)
6	Net AMI Costs/(Savings)	$ (1.935)	$ (1.874)	$ (3.647)	$ (1.139)	$ (1.139)	$ (2.464)	$ (1.161)	$ (2.293)
7									
8	[1] CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14								

If 2018 actual AMI savings of $1.139 million were multiplied by the 2019 inflator of 1.02382, the calculated savings would be $1.166 million, which is very close to the $1.161 million value include in Table C-14 in the MRP Application.

For consistency, FBC has chosen to use the value provided in the FBC 2019 Annual Review for 2019 Rates.

34.5.1 If not confirmed, please calculate the AMI savings using the above approach and explain why this would not be the appropriate adjustment to Base O&M.

Response:

Please refer to the response to BCUC IR 1.34.5.

34.6 Please provide a revised Table C2-14 if necessary.

Response:

Please refer to the response to BCUC IR 1.34.1.

35.0 Reference: FBC BASE O&M

Exhibit B-1, Section C2.5, pp. C-43 – C-48, Table C2-14; FBC PBR Application proceeding, Exhibit B-1, p. 131

lngTemporary 2018 Net Savings – Bad Debt Expense

On page C-45 of the Application, FBC states the following:

> 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 of $0.5 million. The $0.5 million of bad debt expense experienced in 2018 cannot reasonably be considered to be representative future bad debt expense…Therefore, the lower bad debt spending in 2018 of approximately $0.5 million is considered temporary in nature…

On page 131 of the FBC PBR Application, FBC stated the following: "The forecast estimate of $630 thousand annually for 2013, and for the 2014-2018 period is based on historical write-offs and recoveries as well as an estimated amount of monthly billed revenue for all rates."

35.1 Please confirm, or explain otherwise, that $0.630 million was included in FBC's Base O&M related to bad debt expense for the Current PBR Plan term.

Response:

FBC confirms that $0.630 million was included in FBC's Base O&M related to bad debt expense for the Current PBR Plan term. This was a forecast of bad debt expense for 2013 and the actual bad debt expense for 2013 was $0.956 million.

35.2 Please provide the formula and actual bad debt expense for years' 2014 through 2018 and the formula and projected bad debt expense for 2019.

Response:

FBC does not use a formula to forecast bad debt expense. Rather, it is funded within the O&M formula in the Current PBR Plan. See the table below for FBC's actual bad debt expense for the years 2014-2018 and projected bad debt expense for 2019.

Please note that bad debt expense may fluctuate from year to year due to overall economic conditions. As a result, FBC uses a combination of recent experience as well as forecasted revenue to determine current year projections.

	2014	2015	2016	2017	2018	2019
Bad Debt Expense[42] ($)	1,217,093	1,276,247	877,490	1,037,224	471,147	1,000,000

35.3 Please provide FBC's forecast estimate of bad debt expense for 2020 using the same approach as was used to calculate FBC's bad debt expense in the PBR Application and provide all calculations.

Response:

FBC does not have a forecast estimate of bad debt expense for 2020 and is not able to provide an estimate of bad debt expense for 2020 using the same approach as was used in the 2014-2018 PBR Application, because a monthly estimate of billed revenue for all rates is not available at this time.

Further, bad debt expense is part of the 2019 O&M base which is escalated by average customers and inflation. Bad debt expense for 2020 will be embedded in the 2020 inflation-indexed O&M which will be determined in FBC's Annual Review for 2020 Rates.

35.4 Please explain why, when considering all areas of FBC's O&M expenses, FBC has not been able to identify any cost increases in 2018 which it would consider "temporary" and would therefore serve to offset the temporary savings.

Response:

FBC's 2018 net overall achieved O&M savings of approximately $0.94 million (actual expenditures compared to allowed) is comprised of a number of both favourable variances (savings) and unfavourable variances (costs), some of which offset one another. However, the

[42] As included in the allowance for doubtful accounts each year.

final overall 2018 results indicate a net overall savings (net of the favourable and unfavourable variances) of which a portion have been classified as temporary.

For the purpose of establishing a reasonable and appropriate O&M Base for the proposed MRP, FBC focused on reviewing the net overall O&M savings to identify the more material items that are considered temporary and non-sustainable. This is to ensure that adequate O&M funding is included in the 2019 O&M Base for the term of the MRP. From FBC's perspective, temporary savings are generally defined as savings that are not expected to be repeated and therefore require funding in the following year(s).

With the above context, FBC reviewed the 2018 overall net O&M savings achieved to identify the portion that is considered temporary and non-sustainable. For the reasons discussed on page C-45 of MRP Application, the bad debts savings were determined to be temporary in 2018 and that past experience suggests higher bad debts expense will be incurred in the future. As a result, the addback of $0.5 million for 2018 temporary bad debts savings to achieve the 2019 O&M Base is required.

36.0 Reference: FBC O&M BASE

Exhibit B-1, Sections C2.5, C4.4.3, pp. C-45, C-113; FBC PBR Plan Application proceeding, Exhibit B-1, p. 145

Adjustments – Mandatory Reliability Standards (MRS)

On page C-45 of the Application, FBC states the following:

> FBC has also been approved to recover incremental costs of MRS compliance not included in Base O&M. The $0.940 million 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 [Assessment Report] 10.

On page 145 of the FBC PBR Application, FBC provided the following table:

Table C4-18: Mandatory Reliability Standards O&M Review ($ thousands)

(Including Deferred O&M Expense)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ 856	$ 1,328	$ 914	$ 1,709	$ 1,770
Non-Labour	-	160	171	273	379	380
Total O&M	**$ -**	**$ 1,016**	**$ 1,499**	**$ 1,187**	**$ 2,088**	**$ 2,150**

36.1 Please confirm, or explain otherwise, that the 2013 Base MRS O&M expenses were $2.15 million.

Response:

Confirmed.

36.2 Please provide the formula and actual O&M costs for MRS (excluding Z-factor MRS) for years 2014 through 2018 and the formula and projected amounts for 2019. Please separate these annual costs between labour and non-labour.

Response:

Under the Current PBR Plan, FBC's formula O&M expense is determined at the aggregate level. For this reason, FBC is not able to provide formula allowed O&M Expense for the years 2014 through 2019.

Actual and projected costs, excluding incremental (forecast and Z-factor costs) for 2014 through 2019P are provided in the table below.

	2014	2015	2016	2017	2018	2019P
Base O&M						
Labour	$ 1,684	$ 1,460	$ 1,439	$ 1,566	$ 1,706	$ 1,863
Non-Labour	471	535	533	457	391	302
Total	2,156	1,995	1,972	2,023	2,097	2,165

Labour includes FortisBC employee wages while Non-Labour includes costs related to contractors, consultants, staff expenses, etc.

36.2.1 For each year, please provide a detailed breakdown and description of the MRS O&M costs.

Response:

Please refer to the response to BCUC IR 1.36.2.

36.3 Please clarify if capital spending on MRS is included in FBC's base capital under the Current PBR Plan.

Response:

Sustainment capital expenditures for MRS at the time of filing the Current PBR Plan were included in the Base capital under SCADA System Sustainment, and it is not possible to separately identify the expenditures related to MRS. Incremental capital spending that was part

of approved Z-factor events during the Current PBR Plan were not included in the Current PBR Plan's Base capital.

Sustainment capital expenditures for approved Z-factor events during the Current PBR Plan are included the Base capital under SCADA System Sustainment for the proposed MRP.

36.3.1 If yes, please provide a detailed breakdown and description of the formula and actual Capital costs for MRS (excluding Z-factor MRS) for years 2014 through 2018 and the formula and projected amounts for 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For the reasons described in that response, FBC is not able to provide formula allowed capital expenditures for MRS for the years 2014 through 2019.

Further, as explained in the response to BCUC IR 1.36.3, it is not possible to identify the actual MRS-related capital costs embedded in the SCADA System Sustainment program.

36.3.2 If no, please explain where capital-related MRS costs are recorded under the Current PBR Plan and provide a detailed breakdown and description of the forecast and actual Capital costs for MRS (excluding Z-factor MRS) for years 2014 through 2018 and the formula and projected amounts for 2019.

Response:

Please refer to the response to BCUC IR 1.36.3.

36.4 For years 2014 through 2018, please provide the forecast and actual incremental O&M and capital costs incurred for MRS compliance. As part of this response, please provide a breakdown of O&M and capital costs by assessment report and identify which of the costs are one-time costs and which are ongoing costs.

Response:

The actual incremental O&M and capital costs for MRS compliance are provided in the tables below.

Table 1: FBC Incremental MRS O&M Expense 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Forecast O&M - Compliance Audits						
Forecast	$ -	$ 350	$ -	$ -	$ 350	$ -
Actual	-	375	-	-	341	-
Z-Factor - Assessment Report No. 8						
Forecast	-	-	455	50	540	540
Actual	-	-	464	53	532	540
Z-Factor - Assessment Report No. 10						
Forecast	-	-	-	-	180	400
Actual	-	-	-	-	151	400

Table 2: FBC Incremental MRS Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Z-Factor - Assessment Report No. 8						
Forecast	$ -	$ -	$ -	$ 1,350	$ 50	$ 80
Actual	-	-	-	1,371	72	80
Z-Factor - Assessment Report No. 10						
Forecast	-	-	-	-	-	2,700
Actual	-	-	-	-	-	2,700

AR8 O&M one-time costs are over the 2016-2017 time period with ongoing costs starting in 2018 and beyond. AR8 capital one time costs are in 2017 time period with ongoing costs starting in 2018 and beyond. The incremental O&M costs included in Base O&M for the MRP are the projected $0.940 million projected for 2019 plus an additional $0.600 million for the expected increase in costs beginning in 2020 to maintain compliance with AR 10.

AR10 O&M one-time costs are over the 2018-2019 time period ongoing costs starting in 2020 and beyond. AR10 capital one-time costs are in 2019 with ongoing costs starting in 2020 and beyond.

36.4.1 Please provide a table showing the costs identified above in comparison with FBC's initial estimates provided during the review of each of the past MRS assessment reports.

Response:

FBC provided estimated cost ranges at the time of the assessment period for Assessment Report No. 8 (AR8) and Assessment Report No. 10 (AR10). FBC did not differentiate between capital and O&M in the estimated costs at the time. FBC refined the estimates and separated O&M and Capital once the revisions to the standards were adopted and effective dates established by the BCUC. FBC then put forward the estimates as part of the Annual Review process. Both of these are shown in the table below.

	Assessment Report Submission ($ thousands)				Annual Reviews ($ thousands)			
	One Time		Ongoing		One Time		Ongoing	
	Low	High	Low	High	O&M	Capital	O&M	Capital*
AR8	$ 965	$ 1,430	$ 475	$ 650	$ 517	$ 1,371	$ 540	$ 100
AR10	$ 3,315	$ 4,270	$ 2,843	$ 3,470	$ 551	$ 2,700	$ 1,000	$ 100

*Sustainment Capital over 5 years with IS hardware replacement in 5th year

36.4.2 Please indicate if all of the costs identified in the above response are attributable to approved Z-factor events during the Current PBR Plan term. If no, please separately identify which costs were recorded as Z-factor costs and which costs were recorded within the formula spending.

Response:

All the above costs identified in the response to BCUC IR 1.36.4.1 were attributable to approved Z-factor events during the Current PBR Plan.

36.5 For each year of the proposed MRP term, please provide a detailed breakdown and description of the forecast for MRS-related capital and O&M spending, including the spending attributable to each MRS assessment report.

Response:

FortisBC (FEI and FBC) is proposing an Index-Based approach based on total O&M per customer to determine overall O&M funding for the MRP. As a result, FortisBC has not prepared a forecast of O&M over the term of the proposed MRPs.

In Table C2-14 on page C-44 of the Application, $1.540 million in ongoing MRS-related O&M expense was identified in the calculation of 2019 Base O&M, comprised of $0.940 million as identified in the response to BCUC IR 1.36.4 plus an additional $0.600 million for the expected increase in costs beginning in 2020 to maintain compliance with AR 10.

FBC is unable to separately identify the amount of MRS-related capital expenditures that have been included in the SCADA Systems Sustainment expenditures, as stated in the response to BCUC IR 1.36.3. The table below provides the forecast capital expenditures associated with AR8 and AR10 over the period 2020-2024.

	2020	2021	2022	2023	2024
Z-Factor - Assessment Report No. 8	$ 108	$ 109	$ 768	$ 55	$ 87
Z-Factor - Assessment Report No. 10	97	98	99	99	544
Total	$ 205	$ 207	$ 867	$ 154	$ 631

Expenditures are higher in 2022 for AR8 and in 2024 for AR10 because of infrastructure replacement which occurs at five-year intervals, similar to other IS systems.

36.5.1 Please further break down the costs by standard, for each standard with a material forecast spending.

Response:

FBC does not track costs on a per-standard basis (and it is not feasible to do so). Therefore, FEI is unable to provide the requested information.

36.5.2 Please provide a comparison of the costs identified above with FBC's initial estimates provided during review of the MRS assessment reports.

Response:

Please refer to the response to BCUC IR 1.36.5.1.

On page C-113 of the Application, FortisBC states the following:

> 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.

36.6 Please confirm, or explain otherwise, that FBC proposes to treat only the incremental O&M and capital-related MRS compliance costs as flow-through items during the proposed MRP term. As part of this response, please also confirm, or explain otherwise, that FBC does not propose to seek exogenous factor treatment for any MRS costs during the proposed MRP term.

Response:

FBC confirms that only incremental O&M and capital MRS compliance costs will be treated as flow-through items during the MRP term. Incremental MRS compliance costs are triggered by BCUC orders adopting new, or amending, MRS for BC. Since the procedure for adoption of new standards is well established and well understood, FBC does not believe it is necessary to revisit the appropriateness of the flow-through treatment on each occasion by applying for exogenous factor treatment.

36.7 Please provide forecasts of spending related to MRS Assessment Reports No. 11 and 12 and confirm, or explain otherwise, that these costs are not included in the proposed 2019 Base O&M or the five-year forecast capital amounts.

Response:

The BCUC issued Order R-33-18 on September 27, 2018 adopting standards and establishing effective dates for Assessment Report No. 11. FBC identified minor costs to comply with Assessment Report No. 11 and these costs are included in FBC's proposed 2019 Base O&M.

The review for Assessment Report No. 12 is currently in process. The standards have yet to be adopted and an effective date yet to be established. FBC has not determined the costs related to Assessment Report No. 12 and has therefore not included them in 2019 Base O&M or in forecast capital expenditures.

36.8 Please discuss the reasonableness of removing all MRS O&M and capital from formula O&M regular capital and instead forecasting these costs annually, similar to FEI's proposal for integrity digs.

Response:

FortisBC does not consider it reasonable to remove all MRS from the index-based O&M Expense and the forecast of regular capital expenditures. The reasons that FEI has proposed to treat integrity digs outside of index-based O&M Expense are explained in detail on pages C-22 to C-24 of the Application and are repeated here:

> 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.

The costs of complying with existing MRS are not subject to uncertainty or variability to the same degree as the costs of integrity digs; therefore, there is no reason to exclude these costs from index-based O&M Expense. Similarly, there is no reason to exclude the ongoing capital costs of existing MRS from the five-year forecast provided in Section C3.4 of the Application. For clarity, FortisBC is proposing to forecast annually any incremental O&M and capital costs it incurs in complying with new or amended MRS requirements (see Section C4.4.3 of the Application). The only proposed change is to forecast annually new MRS requirements instead of applying for exogenous factor treatment.

While removing the entirely of the MRS expenses from indexed O&M may increase the transparency of MRS expenditures, the suggested treatment would be inconsistent with the treatment of other ongoing O&M expenses and with the intent of the O&M-related aspects of the MRP. Excluding portions of O&M from the indexing mechanism weakens the Utilities' ability and incentives to efficient management of expenses and also reduces the amount of indexed O&M Expense eligible for earnings sharing to the benefit of customers. FBC submits that in the case of ongoing MRS expenses there is no net benefit to the suggested treatment.

36.8.1 Please discuss the pros and cons of the above approach.

Response:

Please refer to the response to BCUC IR 1.36.8.

37.0 Reference: FBC O&M BASE

Exhibit B-1, Section C2.5, p. C-46

Deferrals – Manual Meter Reading Costs

On page C-46 of the Application, FBC states the following:

> 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 meter reads. Revenue from the manual meter read fees will be recorded in Other Revenues.

37.1 For each year since the inception of the AMI Radio-off option, please provide the actual O&M expenses for reading the meters and the actual revenues. Please also provide the projected 2019 O&M and revenues.

Response:

The actual and projected expense and revenue for Radio-off meter reading is provided in the table below.

AMI Radio-off Expense and Revenue, 2014-2019P ($000s)

	2015	2016	2017	2018	2019P
Expense	$ 40	$ 327	$ 315	$ 252	$ 180
Revenue	(42)	(273)	(247)	(230)	(180)
Net Expense (Revenue)	$ (2)	$ 53	$ 68	$ 22	$ -

37.2 Please provide a breakdown and description of the estimated $0.180 million O&M expense.

Response:

O&M expenses for Radio-off meter reading consists primarily of labour and vehicle expenses. Projected 2019 expenses are provided in the table below (in thousands).

	2019P
Labour	$ 132
Vehicles	48
Total Expense	$ 180

37.3 Please provide the forecast annual revenue for the proposed MRP term from the manual meter read fees and provide the supporting calculations and assumptions.

Response:

FBC forecasts approximately 2,300 radio-off meters for 2019 and assumes an average of four reads per year per radio-off customer. The manual read fee as approved by Order G-40-19 is $19.50. Revenue is calculated as 2,300 x 4 x $19.5 = $179,400.

37.4 Please confirm, or explain otherwise, that the variances between the forecast and actual revenues related to the manual meter readings will be subject to earnings sharing under the proposed MRP.

Response:

FBC confirms that variances between forecast and actual revenues from manual meter readings will be subject to earnings sharing.

37.4.1 If not confirmed, please explain why the different treatment of revenue variances compared to the O&M variances is appropriate.

Response:

Please refer to the response to BCUC IR 1.37.4.

38.0 Reference: FBC O&M BASE

Exhibit B-1, Section C2.5, p. C-46

Flow-through Treatment

On page C-46 of the Application, FBC states: "As the AMI project is now complete, the ongoing savings of $1.161 million have been incorporated into the Base O&M."

38.1 Please explain the basis for FBC's expectation that $1.161 million is representative of the expected AMI savings during the term of the proposed MRP. Please explain all assumptions.

Response:

AMI is now fully embedded in the electric organization, meaning that all processes related to its ongoing operation have been stabilized and optimized. As such, FBC does not expect further changes in costs or savings in the categories identified in CPCN application. Therefore, it is appropriate to embed those costs and savings into Base O&M.

As part of normal operations, FBC will continue to look for ways to optimize the use of all of its processes and assets, including those related to AMI.

39.0 Reference: FBC O&M BASE

Exhibit B-1, Section C2.5, pp. C-40 – C-48

New Funding for Term of Proposed MRP

FBC provides the following table on page C-47 of the Application:

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**

39.1 Please explain how the incremental engagement O&M costs were allocated between FEI and FBC and provide all supporting calculations. Please also explain why the allocation method is appropriate.

Response:

As indicated on pages C-35 and C-36 of the Application describing the additional Digital Communications Advisor position and supporting costs funding required of $0.2 million, FEI's portion is $0.16 million with FBC's portion $0.04 million.

The funding was allocated between FEI and FBC based on the approximate number of employees in FEI (80 percent) and FBC (20 percent). The selection of the number of employees as the cost driver is consistent with that proposed in the Shared Services study in Appendix D4 for treatment of similar costs, where the use of the employees as the cost driver was determined to be appropriate for shared costs in the Communications and External Relations group.

FBC provides the following table on page C-47 of the Application:

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

39.2 Please provide the account number (based on the account codes provided in Appendix A3-2 to the Application) which each of the costs provided in Table C2-16 were recorded in.

Response:

Please see below for the account number which each of the costs provided in Table C2-16 were recorded in:

Particulars	Department	Account Number	Account Description
System Operations, Integrity and Safety			
Tree Management	Operations	562	Transmission Station Expense
		563R-2	Transmission Right of Way Maintenance
		583R-1	Distribution Line Maintenance
		583R-2	Distribution Right of Way Maintenance
		592	Distribution Station Expense
Generation Dam Safety	Generation	542	Structures
Network Operations Apprentice Program	Operations	562	Transmission Station Expense
		563R-1	Transmission Line Maintenance
		583R-1	Distribution Line Maintenance
		592	Distribution Station Expense
Cyber Security	Information Systems	920-6	Salaries Information Services
		921-6	Expenses Information Services
		567	Special Services
Data Analytics [1]	not applicable		

[1] Not applicable as the costs were not yet incurred and therefore not included in Appendix A3-2

39.3 Please provide a detailed breakdown and description of the annual actual and formula amounts for each line item in Table C2-14 for the years 2014 through 2018 and the formula and projected amounts for 2019.

Response:

Under the Current PBR Plan, FBC's formula O&M spending is determined at the aggregate level. FBC does not have disaggregated O&M spending by line item. As a result, FBC is unable to provide formula amounts for each line item.

Following are details of the actual expenditures for each of the line items with expenditures during the years 2014 through 2018 and the projected amounts for 2019.

System Operations, Integrity and Safety

Expenditures for Tree Management, Generation Dam Safety, and the Network Operations Apprentice Program have fluctuated from 2014 through 2018.

Tree Management includes labour and expenses to manage trees on and adjacent to FBC's right of ways and public roadways where power lines are located. The scope of work includes management of tree trimming and removal programs, meeting with landowners, and prioritizing tree encroachments within minimum power line clearances. In 2014 and 2015, some brushing and weed control costs were included in the Tree Management scope of work. In 2019, higher expenditures are expected due to increased Tree Management activities and technical support for brushing crews.

A detailed breakdown of the historical expenditures, excluding the expenditures for the general forest health program where problem trees are addressed, is provided in the table below:

Tree Management	Historical Expenditures ($ millions)					
	2014 A	2015 A	2016 A	2017 A	2018 A	2019 P
Labour	$ 0.753	$ 0.570	$ 0.161	$ 0.169	$ 0.175	$ 0.226
Non-Labour	$ 0.010	$ 0.015	$ 0.025	$ 0.015	$ 0.010	$ 0.042
Total	$ 0.763	$ 0.585	$ 0.186	$ 0.184	$ 0.185	$ 0.268

Generation dam safety includes dam safety inspections as per the BC Dam Safety Regulation, operations maintenance surveillance manual revisions, and the Corra Linn safety review. Regular dam safety inspections are required with more comprehensive dam safety reviews being undertaken every seven years. Operations maintenance surveillance manual updates were completed for the Falls Creek Reservoir and the Rover Creek Reservoir due to a change in their consequence classification. The Corra Linn dam safety review was last completed in 2012 and is planned to be undertaken in 2019. After 2019, additional funding is required to enable FBC to better meet the requirements under the BC Dam Safety Regulation. Base line inspections are required to determine the structural condition.

A detailed breakdown of the historical expenditures for Generation dam safety is provided in the table below:

Generation Dam Safety	Historical Expenditures ($ millions)					
	2014 A	2015 A	2016 A	2017 A	2018 A	2019 P
Labour	$ 0.005	$ 0.011	$ 0.016	$ 0.016	$ 0.043	$ 0.032
Non-Labour	$ 0.010	$ 0.031	$ 0.003	$ 0.009	$ 0.012	$ -
Dam Safety Inspections Total	$ 0.015	$ 0.042	$ 0.019	$ 0.025	$ 0.055	$ 0.032
Labour	-	-	-	-	$ 0.006	-
Non-Labour	-	-	-	-	-	-
OMS Manual Update and Maintenance Total	$ -	$ -	$ -	$ -	$ 0.006	$ -
Labour	-	-	-	-	-	-
Non-Labour	-	-	-	-	-	$ 0.098
Corra Linn Dam Safety Review Total	$ -	$ -	$ -	$ -	$ -	$ 0.098
Total	$ 0.015	$ 0.042	$ 0.019	$ 0.025	$ 0.061	$ 0.130

The Network Operations Apprentice Program helps to ensure adequate skilled staff are available to complete work on a cost effective basis and in a timely manner. The program includes the non-labour cost for apprentice development and is composed of annual trade school fees, expenses, personal protective equipment required for the program, tools and recruitment costs. The labour costs for the apprentices are typically charged directly to the activities performed.

A detailed breakdown of the historical expenditures for the Network Operations Apprentice Program is provided in the table below:

Network Operations Apprentice Program	Historical Expenditures ($ millions)					
	2014 A	2015 A	2016 A	2017 A	2018 A	2019 P
Labour	$ -	$ -	$ -	$ -	$ -	$ -
Non-Labour	$ 0.036	$ 0.071	$ 0.080	$ 0.054	$ 0.139	$ 0.068
Total	$ 0.036	$ 0.071	$ 0.080	$ 0.054	$ 0.139	$ 0.068

Cyber Security

In 2018, total expenditures were approximately $431 thousand, comprised of $280 thousand for labour expense, with the remaining $151 thousand for non-labour (consulting, software, employee expense).

FortisBC had a successful year in 2018 in terms of cybersecurity. FortisBC was able to leverage external resources to firm up the cybersecurity resources as a whole, taking into account the corporate IS cybersecurity position as well as operations. Assessments were completed for a managed security provider, which will add to FortisBC's internal resource capability. Training and awareness were brought to the forefront for FortisBC employees reducing the risk of vulnerabilities caused by phishing.

FortisBC was able to respond to cybersecurity threats and prevent potential material incidents.

39.4 Please confirm, or explain otherwise, that the "Base 2019" column in Table C2-16 is calculated by multiplying the Actual 2018 O&M by the 2019 Inflator.

Response:

Not confirmed.

The columns in Table C2-16 provide the following:

- **Historical Expenditures 2014 to 2018**: These amounts are the actual Historical Expenditures of FBC from 2014 to 2018;
- **Base 2019**: Base 2019 in this table represents the Company's 2019 Projection and the existing funding available in 2019 under the Current PBR Plan;
- **Proposed 2019**: the Proposed 2019 represents the funding required for the O&M Base for the MRP; and
- **Proposed Incremental**: the Proposed Incremental represents the additional funding required compared to the Base 2019 (i.e. the difference between Base 2019 and Proposed 2019).

FBC's approach to calculate the 2019 Base O&M in Table C2-14 is based on taking the Company's total 2018 O&M actual expenditures and applying an inflation factor, incorporating required adjustments and then adding the incremental funding required - New Funding for MRP term. The Proposed Incremental items identified in Table C2-16 of $0.683 million form part of the total New Funding for the MRP term indicated in Table C2-14.

FBC chose the approach of using 2019 Projection instead of applying an inflation factor to the different line items as a starting point for determining its incremental O&M funding as it is more representative of the anticipated spending. Recognizing there are various cost pressures, FBC considers that its overall O&M funding requirements for 2019 should remain within the Allowed O&M funding provided for under the Current PBR Plan, although there will be variations within the departments as indicated in Table C2-16. FBC notes that, had it calculated the Base 2019 column by applying the inflation factor to the 2018 Actual column, as suggested in the question, the Proposed Incremental amounts would have been higher.

39.4.1 If not confirmed, please explain why this calculation would not be more appropriate given the approach to calculating 2019 Base O&M in Table C2-14 of the Application.

Response:

Please refer to the response to BCUC IR 1.39.4.

On page C-47 of the Application, FBC states that it 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."

39.5 Please confirm, or explain otherwise, whether the budget for Tree Management in Table C2-16 covers tree management resulting from storm damage.

Response:

The budget for Tree Management in Table C2-16 does not cover tree management resulting from storm damage. Tree damage resulting from storms is included in the infrastructure repair cost.

39.6 Please explain why Tree Management O&M decreased significantly between 2015 and 2016 and why spending continued to be at a lower level during the remainder of the Current PBR Plan term.

Response:

The decrease in Tree Management expenditures between 2014 and 2015 was the result of separating Tree Management and Vegetation Management. Prior to 2016, Vegetation Management and some vegetation clearing costs were included in Tree Management. The costs were separated to give better visibility of expenses.

39.7 Please explain whether the Tree Management O&M in Table C2-16 is related to transmission and/or distribution infrastructure.

Response:

The Tree Management O&M in Table C2-16 is related to transmission and distribution infrastructure.

39.8 Please explain what specifically is driving the need for increased spending for Generation Dam Safety and provide a breakdown of the incremental O&M of $0.232 million.

Response:

Regular dam safety reviews, single device isolation (SDI) certification and penstock assessments are driving the increased spending for generation dam safety. The breakdown is as follows:

Table 1

Generation Dam Safety	Incremental Increased Spending ($ millions)
Dam safety reviews and document control	$0.170
Single Device Isolation (SDI) certification and penstock assessment	$0.062
Total	$0.232

Periodic dam safety reviews are required by section 20 of the BC Dam Safety Regulation for all dams that are of high, very-high or extreme consequence classification. All FBC-owned generation dams are classified as extreme consequence, which requires the highest frequency of dam safety related activities and reviews. In addition, dam safety regulations and best practices continue to refine the details related to inspections, instrumentation requirements and documentation required to support dam safety compliance.

The Single Device Isolation certifications are required for dam intake gates, spillway, tailrace gates, and stoplogs to maintain compliance with BC Occupational Health and Safety Regulation

9.18(3) (b) and protect personnel and equipment. The SDI certifications are typically completed on a five-year cycle or as required by the certifying engineer. A five-year cycle is an industry best practice, and due to the advanced age of the majority of the gates in use at FBC plants, some gates require a shorter cycle.

Dam penstocks assessments are required to determine the structural condition of the penstocks and identify any repairs.

39.8.1 Please discuss the implications, if any, of FBC's comparatively lower level of spending on Generation Dam Safety during the Current PBR Plan term.

Response:

FBC's historical spending during the Current PBR Plan and proposed spending in the MRP are both based on the requirements of the BC Dam Safety Regulation. Therefore, FBC does not see any implications due to the difference in the level of spending.

39.9 Please explain why the 2019 Base O&M for Generation Dam Safety of $0.130 million is over 100 percent higher than the 2018 O&M spending of $0.061 million.

Response:

Please refer to the response to BCUC IR 1.39.8.

39.9.1 As part of the above response, please explain why the "Base 2019" column in TableC2-16 is not calculated by multiplying the Actual 2018 O&M by the 2019 Inflator and why this calculation would not be more appropriate given the approach to calculating 2019 Base O&M in Table C2-14 of the Application.

Response:

The 2019 Base O&M in Table C2-14 includes proposed incremental items identified in Table C2-16 for the term of the MRP. For the column labelled as “Base 2019“ representing also the 2019P, FBC chose not to apply an inflation factor to the 2018 Actual Generation dam safety costs to calculate the “Base 2019” because the 2018 Actual is not representative of the work that is required in 2019. Using 2019 projected Generation dam safety expenditures is more representative of the anticipated O&M spending in 2019.

39.10 Please provide a breakdown and description of the 2018 Cyber Security O&M of $0.431 million.

Response:

The following table breaks down the costs and provides a description of the 2018 cybersecurity O&M expense:

	($000s)
Labour	280
Consulting	131
Software	10
Employee Expenses	8
Miscellaneous	2
Total	431

39.11 Please explain how the incremental Cyber Security O&M costs were allocated between FEI and FBC and provide all supporting calculations. Please also explain why the allocation method is appropriate.

Response:

The incremental cybersecurity O&M costs include labour and managed services.

The incremental labour cost of the shared customer security position were allocated according to the relative number of customers (approximately 1.05 million gas and 150 thousand electric customers). As a result, 12 percent of the overall cost ($0.018 million) was allocated to FBC and the remaining 88 percent ($0.132 million) has been allocated to FEI. This allocation is appropriate as the position is focused on the safety and security of customers, with FEI and FBC customers benefiting from the service proportionally.

The managed services costs were allocated according to the relative number of employees (approximately 1,800 gas and 550 electric employees). As a result, 25 percent of the overall cost ($0.062 million) was allocated to FBC and the remaining 75 percent ($0.186 million) has been allocated to FEI. This allocation is appropriate as managed services focus on the security of employee devices and related activities.

On page C-40 of the Application, FortisBC describes the incremental Cyber Security spending for FEI of $0.508 million requested during the proposed MRP term.

39.12 Please confirm that FBC is in compliance with all applicable North American Electric Reliability Corporation - Critical Infrastructure Protection (NERC-CIP) standards.

Response:

FBC is currently in compliance with all BCUC-adopted Mandatory Reliability Standards in effect in BC. As a result of the assessment report process, there is a delay (typically one year) from the adopted standards by FERC/NERC in the US to the BCUC-adopted standards in BC.

39.13 Please provide any risk assessment results that FortisBC has regarding its cybersecurity risks.

Response:

FortisBC completed a Cybersecurity Capability Maturity Model (C2M2) assessment in 2017 conducted by PwC (PricewaterhouseCoopers) that included FEI and FBC.

The C2M2 evaluation focuses on the implementation and management of cybersecurity practices associated with the operation and use of information technology and operational technology assets and the environments in which they operate. The goal is to support ongoing development and measurement of cybersecurity capabilities within any organization by:

- Strengthening organizations' cybersecurity capabilities;
- Enabling organizations to effectively and consistently evaluate and benchmark their cybersecurity capabilities;
- Sharing knowledge, best practices, and relevant references across organizations as a means to improve cybersecurity capabilities;
- Enabling organizations to prioritize actions and investments to improve cybersecurity; and
- Supporting adoption of the National Institute of Standards and Technology (NIST) Cybersecurity Framework.

Extracts from the C2M2 assessment report are included below.

> Overview of FortisBC's Cybersecurity Maturity:
>
> Overall, FortisBC is considered to be mature in regards to its cybersecurity capabilities. Due to the requirement for BCUC MRS CIP compliance, FortisBC is at or near the highest level of maturity in regards to the C2M2 assessment for the most part. There were, however, opportunities to improve cybersecurity maturity and capabilities identified for other aspects of FortisBC.
>
> Findings:
>
> 1. High Maturity was found in the areas of Risk Management, Identity & Access Management, Threat & Vulnerability Management, Situational Awareness, Information Sharing & Communications, Event & Incident Response, Cyber Program Management for the majority of FortisBC.
> 2. Medium Maturity was found in the areas of Asset, Change & Configuration Management, Supply Chain & External Dependencies and Workforce Management.
> 3. Low Maturity was found for Threat & Vulnerability Management and Event & Incident Response in some specific technology areas.

Conclusion:

Overall, FortisBC is considered to be mature in regards to its cybersecurity capabilities. Some minor recommendations for specific technology areas to improve some practices by aligning and leveraging existing capabilities used in regards to cybersecurity by other FortisBC technology areas.

39.14 Please provide any internal audits FortisBC has performed on its cybersecurity risk, identifying any deficiencies found.

Response:

FortisBC conducts penetration testing, as well as internal and external audits as part of Sarbanes-Oxley Act (SOX) compliance. There were no deficiencies specifically identified in any audits, reports or assessments. The reports and assessments have identified areas of cybersecurity to be considered for potential improvement, as well as areas to monitor for changing risk as threat vectors change. The audits, reports and assessments undertaken by FortisBC are used to inform the ongoing approach and strategy towards cybersecurity to maintain a reasonable level of cybersecurity based on good practices.

Auditing and assessment results have informed the cyber security requirements; however, a majority of the incremental cyber security spending is to address the increasing frequencies of security patches and the addition of security services to keep the cyber security risk at an acceptable level.

39.15 Please provide any internal standards FortisBC has written for cybersecurity, outside of the MRS or CIP or externally-mandated standards.

Response:

Outside MRS Critical Infrastructure Protection (CIP) requirements, FortisBC has not written any cybersecurity standards. Instead, FortisBC leverages standards provided by the National Institute of Standards & Technology, International Organization for Standardization, Control Objectives for Information and Related Technologies, and SOX to inform FortisBC's

cybersecurity practices. These sources provide recognized standards that support good cybersecurity practices.

These recognized standards inform FortisBC's cybersecurity practices and policies in regards to things such as password requirements, change control procedures, segregation of duties, access of least privilege, defense in depth, patching, network architecture, application architecture, incident response and supply chain controls.

39.15.1 Please provide a list of any other Canadian utilities that these standards were benchmarked against.

Response:

FortisBC participates in utility industry sub-groups specific to cybersecurity and technology including sub-groups under the Canadian Electric Association, the Canadian Gas Association and the Western Energy Institute. Comparison and information sharing with other participating utilities occurs regularly. Utilities such as BC Hydro, Hydro One, Hydro Quebec, Manitoba Hydro, Sask Power, Enmax, Altalink, Emera and Toronto Hydro are examples of participating utilities. No formal benchmarking has occurred with these or other utilities.

39.16 On page C-40 of the Application, FortisBC describes three new positions it is implementing related to cybersecurity. Please provide a description of each position related to cybersecurity at FortisBC in addition to the new positions.

Response:

The new and existing positions within FortisBC's cybersecurity team include:

- *Director, Information & Infrastructure Security* – Overall responsibility for the direction of FortisBC's cybersecurity strategy and serves as the MRS CIP Senior Manager.
- *Manager, Cybersecurity* – Responsible for implementation of the FortisBC cybersecurity strategy for Corporate and Operations assets.

- *Supervisor, Operations Technology & Security* – Assists the Manager, cybersecurity primarily with FBC (electric) assets and strategies.
- *Supervisor, Operations Technology & Security* - Assists the Manager, cybersecurity primarily with FEI (gas) assets and strategies.
- *Supervisor, Operations Technology & Security* **(NEW)** - Assists the Manager, cybersecurity primarily with FEI (gas) assets and strategies. This position will primarily focus on the security of the gas control system and network.
- *Supervisor, Customer Systems Security* **(NEW)** – Assists and educates FortisBC customers and employees in regards to ongoing scams, phishing attempts and cyber hygiene when it comes to FortisBC accounts and data.
- *Application Programmer/Analyst* **(NEW)** – Reporting to the Supervisor, Operations Technology & Security (gas) this position focuses on the security of the gas control system and network.

Though not directly within the cybersecurity team, the MRS CIP group is responsible for compliance with the BCUC MRS CIP standards that focus on the electric control system and network. These standards also focus heavily on cybersecurity.

As part of the broader organizational structure, there are technical and system analyst positions that report into these managers and supervisors noted above. These technical and system analyst positions support some cybersecurity functions in their roles; however, it is not their primary responsibility. These positions were existing resources within the Information Systems department that were aligned within the organizational structure to the appropriate cybersecurity managers and supervisors.

39.16.1 Please include any corporate reporting structure of these positions, noting any corporate governance structure that may be in place.

Response:

All positions related to cybersecurity report to the Director, Information & Infrastructure Security with the exception of the Mandatory Reliability Standards CIP group, which informally reports to, and collaborates with, the Director, Information & Infrastructure Security who holds the role of CIP Senior Manager. The Mandatory Reliability Standards CIP group currently reports to the Executive Vice President, Operations & Engineering through the FortisBC Engineering department.

The Director, Information & Infrastructure Security is responsible for cybersecurity practices, standards, policies and strategy. The Director is also responsible for reporting and maintaining of KPIs specific to cyber security, including compliance.

39.17 Please provide the intended spend on compliance and reporting with MRS/CIP in the Test Period.

Response:

As discussed on page C-45 of the Application, FBC is projecting that $0.940 million will be required in 2019 and on an ongoing basis for MRS/CIP 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 Assessment Report No. 10.

39.18 Please explain whether FortisBC expects the O&M spending on Cybersecurity to continue to rise in future.

Response:

Cybersecurity is dynamic and evolving rapidly. As a result, FortisBC is unable to predict cybersecurity spending requirements in the future; however, efforts to maintain appropriate levels of cybersecurity are likely to increase based on increasing use of technology along with increasing threats. Continued adjustment of spending is likely.

39.19 As part of the above response, please provide FortisBC's forecast spending on Cybersecurity O&M for each of FEI and FBC for each year of the proposed MRP term.

Response:

The proposed MRPs include in the 2019 Base O&M $595 thousand (Table C2-13) and $1.820 million (Table C2-16) for FBC and FEI respectively. Since the MRPs propose to manage O&M spending using an index-based approach, FortisBC has not prepared a forecast of cybersecurity spending for the MRP term.

D. CAPITAL EXPENDITURES

40.0 Reference: FEI CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.1, pp. C-56 – C-63; Exhibit B-1-1, Appendix B8-1

FEI Growth Capital

FBC provides the following table on page C-58 of the Application:

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

FEI states the following on page C-56 of the Application regarding new customer mains:

> Proposed main extension projects are evaluated through a BCUC-approved main extension (MX) test…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.

FEI states the following on page C-57 of the Application regarding new customer services:

> 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.

40.1 Please separately provide the amount of the annual Contributions in Aid of Construction (CIAC) shown in Table C3-1 of the Application that is attributable to new customer mains and the amount that is attributable to new customer services for years 2014 through 2018.

Response:

The annual Contributions in Aid of Construction (CIAC) that is attributable to new customer mains and to new customer services for the 2014-2018 period is provided in the table below.

FEI Contributions in Aid of Construction ($000s)

	2014	2015	2016	2017	2018
New Customer Mains	(688)	(584)	(653)	(656)	(576)
New Customer Services	(2,959)	(2,076)	(1,765)	(1,919)	(1,885)
Total	(3,647)	(2,660)	(2,418)	(2,575)	(2,461)

40.2 Please provide the annual approved (i.e. formula) expenditures for System Improvements (DP) for years 2014 through 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

In Table A:B8-1-4 of Appendix B8-1, it shows the annual formula versus actual capital variances attributable to "unanticipated system improvements and new stations to supply gas to new customers."

40.3 Please confirm, or explain otherwise, that the "unanticipated system improvements and new stations to supply gas to new customers" costs include the System Improvements (DP) costs proposed to be re-categorized from sustainment to growth capital.

Response:

Confirmed. The "unanticipated system improvements and new stations to supply gas to new customers" costs include cost variances from 2014-2019 associated with the System Improvements (DP) re-categorized from Sustainment to Growth capital. It also includes cost

variances associated with intermediate pressure system improvements and new stations required to support new customers, both of which remain in Sustainment capital.

40.3.1 If confirmed, please provide the amounts in Table A:B8-1-4 which are attributable to System Improvements (DP).

Response:

Table A:B8-1-4 represents the variance between actual expenditures for system improvements and new stations and those forecast in those categories at the time the FEI 2014-2018 PBR Application was filed. FEI is unable to identify which amounts are specifically attributable to System Improvements (DP) because the expenditure forecasts from the time the FEI 2014-2018 PBR Application was filed did not differentiate DP from IP System Improvements. FEI has provided below the actual expenditures in the three categories to show the relative contribution of each over the 2014-2019 term.

($000s)	2014	2015	2016	2017	2018	2019P
System Improvements (DP)	2,476	5,945	3,052	3,633	4,523	2,552
System Improvements (IP)	-	-	728	1,479	1,861	128
New Stations	332	924	911	637	3,439	3,477
Total System Improvements and New Stations to supply gas to new customers	2,808	6,869	4,691	5,749	9,823	6,157

On page 9 of Appendix B8-1 of the Application, FEI states the following:

> FEI forecasts the need for system capacity improvements due to typical growth of core customer load over 5-10 years using system capacity models. These forecasts make assumptions regarding the magnitude and location of load additions to the system based on housing development and growth trends known at the time. The higher than expected customer growth that has taken place during the Current PBR term, and the addition of large new customers has resulted in the need for system improvements and new stations to support the added load described in section 2. The need for capacity upgrades to the system

has been well in excess of what was anticipated at the time of the 2014-2018 PBR Plan Application filing.

On page C-55 of the Application, FEI states the following:

> 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.

40.4 Please confirm, or explain otherwise, whether System Improvements and New Stations to Supply Gas to New Customers will be included in the Growth Capital category for the Proposed MRP period.

Response:

As stated in the response to BCUC IR 1.40.3, System Improvements and New Stations to Supply Gas to New Customers includes: (1) Distribution Pressure System Improvements, (2) Intermediate Pressure System Improvements, and (3) New Stations to supply gas to new customers.

Distribution pressure (DP) System Improvements will be included in the Growth capital category for the proposed MRP term. DP System Improvements include looping of distribution gas mains to increase the capacity of the system to meet increasing customer demand. FEI has proposed this change because the primary driver for these expenditures is customer additions and the timing of the expenditures is generally within the same year that the customer additions take place.

Intermediate pressure (IP) System Improvements and New Stations to supply gas to new customers will remain in Sustainment capital. IP System Improvements include the looping or extension of higher pressure gas mains that carry large volumes of gas to population centers to serve increasing customer demand. New stations are sometimes required to provide a secondary source of supply to a community to support increasing customer demand and improve system resilience. Although these expenditures are primarily driven by customer additions, the expenditures are generally much larger and tend to lead or lag a significant portion of the customer additions that created the need for the work. As such, they are not well suited to the proposed unit cost approach to Growth capital and are, therefore, not included in Growth capital for the MRP.

40.4.1 If not confirmed, please explain the difference between "System Improvements and New Stations to Supply Gas to New Customers" and "System reinforcements to the distribution system."

Response:

Please refer to the response to BCUC IR 1.40.4.

On page C-59 of the Application, FEI states the following:

> 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.

40.5 Please provide the correlation coefficient between service line additions and the spending on each of mains, services, meters and system improvements based on the actual 2014 through 2018 expenditures.

Response:

FEI provides the requested information below.

Growth Capital Correlation Coefficient	Service Line Additions	Gross Customer Additions
New Customer Mains	0.91	0.93
New Customer Services	0.93	0.95
New Customer Meters	0.88	0.94
System Improvements (DP)	0.28	0.29

40.6 Please provide the correlation coefficient between gross customer additions and the spending on each of mains, services, meters and system improvements based on the actual 2014 through 2018 expenditures.

Response:

Please refer to the response to BCUC IR 1.40.5.

41.0 Reference: FEI CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.1, pp. C-56 – C-63; FEI PBR Application proceeding, Exhibit B-1, pp. 227–238

FEI Growth Capital

On page C-60 of the Application, FEI states: "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."

On page C-56, FEI states that the primary driver for Growth capital expenditures is gross customer additions, and that for residential customers, additions are dependent on factors such as new housing starts, land development activity and homeowners converting from other fuels to natural gas along with market capture.

On page 227 of the FEI PBR Application, FEI stated the following regarding growth capital:

> The Forecasting department reviews housing start forecasts, SFD [single family dwellings] and MFD [multi-family dwellings] growth and capture rates and conversion markets to establish a customer additions forecast.
>
> Table C4-11 below summarizes the NET and GROSS customer additions forecasts developed by the Forecasting group which ultimately drives both the new Services and new Meters capital expenditure forecasts.

41.1 Please explain if the approach described in the FEI PBR Application, as provided in the above preamble, is still utilized for new Services and new Meters and if these forecasts still drive capital expenditure forecasts.

Response:

The approach of using a combination of information related to trending for new housing starts for SFD (single family dwellings) and MFD ([multi-family dwellings), capture rates, sales prospect data from the customer data base and conversion market potential to establish a customer additions forecast is utilized for new service and mains forecasting as it bears a relationship to the volume of gross customer additions and hence Growth capital expenditures. Net customer additions are not used in determining the Growth formula in the Current PBR Plan and are not being proposed for the MRP.

41.2 Please provide a detailed comparison of how FEI developed the base growth capital for each of the growth capital components (mains, services and meters) as part of the Current PBR Plan and under the proposed MRP and highlight any differences. Please compare both the calculation of activity levels and unit costs.

Response:

FEI acknowledged in the Annual Reviews during the Current PBR Plan that the Growth capital formula did not provide adequate funding to meet the needs of customers requesting to attach to FEI's natural gas distribution system. For this reason, FEI is proposing a Growth capital formula that better represents the funding required to meet its obligation to attach customers when they request natural gas service.

In preparation for this Application, FEI carefully considered the key components of Growth capital expenditures and developed its proposal for a new base unit cost and a new formula that better reflects the activity levels of customers requesting natural gas service. A comparison of how FEI developed the Base Growth capital for each of the Growth capital components as part of the Current PBR Plan and the proposed MRP is provided below:

1. **Approved versus Average Historical Growth expenditures:** Under the Current PBR Plan, the formula based approach for Growth capital uses the 2013 approved capital expenditures (with adjustments) as the Base. Under the proposed MRP, FEI is proposing to use a three year average of 2016-2018 actual Growth capital costs (with adjustments) to determine the 2019 Base. FortisBC made this change because, as outlined in the Application, the Growth capital formula is not reflective of the costs that the utility is experiencing to connect customers. By using an average of recent actuals, the 2019 Base is reflective of the costs to connect customers today.

2. **Growth Activities**: Under the Current PBR Plan, Growth capital is tied to a lagging growth factor based on one half of year-over-year changes in service line additions,[43] whereas in the proposed MRP FEI is proposing to use a forecast of Gross Customer Additions with a true-up for forecast variances. A Gross Customer Addition is a new meter and /or service to a new customer. As discussed in FEI's Annual Reviews, more customers are attaching to each service line than have in the past, which is primarily due to more densified housing construction (townhomes and condominiums). Gross Customer Additions reflects the number of customers attaching irrespective of the number of service lines, and is a superior cost driver because costs are driven by the number of connections, not just service lines.

[43] FEI proposed to use a forecast of service line addition in the 2014-2018 PBR Application.

3. **Categories included in Growth capital**: Under the Current PBR Plan, the Growth capital components include New Customer Mains, Services and Meters. In the proposed MRP, FEI is including Distribution Pressure (DP) system improvements and Growth CIAC, in addition to New Customer Mains, Services and Meters. DP system improvements and Growth CIAC are driven by customer growth, so including them in the Base is logical.

4. **Unit Cost:** Under the Current PBR Plan, the 2013 Base unit cost is the 2013 approved Brouth capital costs per Service Line Addition, calculated as the 2013 approved New Customers Mains, Services and Meters, with adjustments, divided by the forecast

5. **Service Line Additions:** A Service Line Addition is defined as a riser, and a riser may have one or many meters/customers attached. In the proposed MRP, the 2019 Growth capital base unit cost is the average 2016-2018 actual Growth capital cost per Gross Customer Addition. It is calculated as the average 2016-2018 inflation adjusted actuals for New Mains, Services, Meters, DP system improvements and Growth CIAC, plus construction price increase and muster kit and material allocation adjustments, divided by the 2016-2018 average Gross Customer Additions. Please refer to Section C3.3.1.3.2 – Proposed Growth Capital Base Unit Cost for details of how FEI developed the Base Growth capital under the proposed MRP.

Details of the Base Growth capital under the Current PBR Plan are described in Section B6.2.5.1 2013 Base Capital of FEI's 2014-2018 PBR Application for.

41.2.1 As part of the above response, please explain in detail the rationale for FEI's proposed changes in approach, if any, to determining the base growth capital for the proposed MRP.

Response:

Please refer to the response to BCUC IR 1.41.2.

On page 227 of the FEI PBR Application, FEI provided the following table:

Table C4-10: Conference Board of Canada Housing Starts Forecast in FEI Service Territory

	2012	2013	2014	2015	2016	2017	2018
SFD	8,142	7,854	8,415	9,027	9,213	8,974	8,663
MFD	20,213	19,186	19,586	21,915	23,260	23,291	22,649
Total	**28,355**	**27,040**	**28,000**	**30,942**	**32,473**	**32,265**	**31,312**
% Growth SFD		-4%	7%	7%	2%	-3%	-3%
% Growth MFD		-5%	2%	12%	6%	0%	-3%

41.3 Please provide the same information as was provided in the above table for the following years: Actual 2014 through 2018, Projected 2019, and Forecast 2020 through 2024.

Response:

Please see the table below for Conference Board of Canada Housing Starts for the following years: Actuals 2014 through 2017 and Forecast 2018 through 2024. Please note that the 2018 actual housing starts will not be available until Q4 of this year.

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
SFD	9,569	10,152	12,278	12,348	11,611	10,837	8,935	7,702	7,149	6,893	6,799
MFD	18,787	21,294	29,565	31,318	29,720	27,407	24,678	22,412	21,273	20,744	20,633
Total	**28,356**	**31,446**	**41,843**	**43,666**	**41,331**	**38,244**	**33,613**	**30,114**	**28,422**	**27,637**	**27,432**
% Growth SFD		6%	21%	1%	-6%	-7%	-18%	-14%	-7%	-4%	-1%
% Growth MFD		13%	39%	6%	-5%	-8%	-10%	-9%	-5%	-2%	-1%

For purposes of forecasting customer growth (net customer additions) FEI uses the Conference Board of Canada (CBOC) Housing Starts forecast to arrive at a net additions forecast which is consistent with past practice. This method divides FEI's actual net additions into single and multi-family dwellings and forecasts each cohort independently. The aggregate net additions forecast is the sum of single and multi-family forecasts. Commercial net additions are forecast using a three year average.

While the CBOC Housing Starts forecast provides a directional indication of trending for housing starts, FEI does not use it for forecasting gross customer additions for a number of reasons. First, the CBOC forecast does not correlate well with the timing of FEI's gross customer additions as there is often a time lag for when new mains and service connections are installed. Second, conversion customers are not captured in the CBOC Housing Starts forecast. Third, multifamily housing units (condominiums and townhouses) are counted individually from a CBOC perspective but the whole building may be bulk served off one meter from FortisBC (ie: a 100 unit condominium may only have one or two meters for the entire development). FortisBC would count this as one/two customers whereas CBOC counts each individual unit as a housing

start. This difference in counting can account for a significant difference between housing starts and customer attachments.

On page 228 of the FEI PBR Application, FEI provided the following table:

Table C4-11: Actual and Forecasted Net and Gross Customer Additions

	2012 Actual	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Net Customer Additions	4,747	4,631	4,982	5,328	5,443	5,344	5,173
% Change		-2.4%	7.6%	6.9%	2.2%	-1.8%	-3.2%
Gross Customer Additions	8,738	8,624	8,946	9,341	9,505	9,382	9,189
% Change		-1.3%	3.7%	4.4%	1.8%	-1.3%	-2.1%

41.4 Please provide the same information for net and gross customer additions as was provided in the above table for the following years: Actual 2018, Projected 2019, and Forecast 2020 through 2024.

Response:

FortisBC provides the Actual 2018 and Projected 2019 results in the table below.

	2018 Actual	2019 Projection
Net Customer Additions	21,087	19,174
% Change		-9%
Gross Customer Additions	22,439	18,540
% Change		-17%

FortisBC has not produced a forecast of the number of customers and customer connections for the term of the MRPs. The Application sets out the framework and mechanism by which inflation-indexed O&M and Growth capital (for FEI only) will escalate Base O&M and Growth capital over the term of the MRPs. At each Annual Review for rates, FortisBC will forecast the average number of customers and gross customer additions (for FEI only) for the upcoming year to determine Gross O&M and Growth capital. This mechanism will allow the Companies to bring forward current forecast information on customer growth and attachments based on the most up-to-date operating environment and market trends.

On pages 237 and 238 of the FEI PBR Application, FEI provided the following information regarding service line additions expenditures:

Table C4-17: Historical Service Activities, Unit Costs & Expenditures

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
Gross Customer Additions	9,587	6,254	8,738	8,624	11,100
Ratio of Service Additions to Gross Customer Adds	0.98	1.27	0.90	0.90	0.72
Activities (riser or services)	9,382	7,958	7,898	7,762	7,989
Unit Costs ($ per service - riser)	1,479	1,775	2,206	2,163	1,616
Expenditures ($000's)	13,874	14,423	17,423	16,791	12,910

Table C4-18: Forecast Service Activities, Unit Costs & Expenditures

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Gross Customer Additions	11,100	8,946	9,341	9,505	9,382	9,189
Ratio of Service Additions to Gross Customer Adds	0.72	0.90	0.90	0.90	0.90	0.90
Activities (riser or services)	7,989	8,051	8,407	8,555	8,444	8,270
Unit Costs ($ per service - riser)	1,686	2,280	2,320	2,363	2,409	2,462
Expenditures ($000's)	13,471	18,360	19,502	20,214	20,337	20,363

41.5 Please provide the same information as was provided in Table C4-17 of the FEI PBR Application for the years 2014 through 2018 (Actual) and 2019 (Projection).

Response:

The 2014 through 2018 Actual and 2019 Projected Service Activities, Unit Costs and Expenditures are provided in the table below.

	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
Ratio of Service Additions to Gross Customer Adds	0.82	0.76	0.71	0.76	0.74	0.76
Activities (riser or services)	11,103	12,392	12,288	15,856	16,606	14,116
Unit Costs ($ per service/riser)	2,256	2,484	2,598	2,497	3,283	3,369
Expenditures ($000s)	25,049	30,785	31,927	39,594	54,511	47,556

41.6 Please calculate the 2019 Base capital for new customer services using the same approach as was used in the Current PBR Plan. Please show all calculations and explain all assumptions.

Response:

FortisBC assumes that the question is in regard to FEI's 2019 Base Growth capital and not solely the part of Base Growth capital that relates to 'services'. Although Tables C4-17 and C4-18 from FEI's 2014-2018 PBR Application show the unit cost for services, which is a component of 2013 Base Growth capital, those tables were developed for a specific purpose - to develop a high level forecast of Growth capital expenditures for comparison to the formula unit cost approach that was proposed. The 2013 Base Growth capital for the calculation of the formula was derived separately, using the approved cost of a new service line as well the meter, regulator and average main extension costs (see Table B6-6 of the 2014-2018 PBR Application). Therefore, FEI has answered this question using the manner in which 2013 Base Growth capital was determined as the point of comparison.

In the Current PBR Plan, 2013 Base capital was derived by using 2013 Approved[44] Growth capital with adjustments. While a 2019 approved Formula for Growth capital exists, it is not comparable to FEI's proposed method due to the addition of distribution system improvements, for example. Furthermore, producing a 2019 Base Growth capital from the 2019 Formula is essentially a continuation of the existing plan without regard for changing conditions and operating environment.

However, to be responsive, FEI has provided below a 2019 Base Growth capital in a manner that is similar to how 2013 Base was derived. In doing so, FEI has substituted the 2013 Approved with the 2019 Formula amount, has not included Distribution System Improvements and Growth CIAC, and has utilized Service Line Additions rather than Gross Customer Additions, as that is the method that was used in 2013.

Line	Particulars	2019 Approved	Reference
1	Growth Capital ($000)	40,143	FEI's Annual Review for 2019 Rates,
2			Schedule 4, Line 27, Column 2
3	*Adjustments*		
4	Construction Price Increase	9,146	Exhibit B-1, Table C3-3, Line 13
5	Muster Kit and Material alloc impact	642	Exhibit B-1, Table C3-3, Line 14
6			
7	Total 2019 Growth Capital Base ($000)	49,930	Sum of Lines 1 through 5
8	Service Line Additions	13,678	
9			
10	Total Unit Cost Growth Capital $/SLA	$ 3,650	Line 7 x 1000 / Line 8

[44] Order G-44-12 approved the FortisBC Energy Utilities' 2012-2013 Revenue Requirements and Rates.

41.7 Please recreate Table C4-18 from the FEI PBR Application for Base 2019 and Forecast 2020 through 2024 under the following two approaches: (i) the proposed approach in this Application; and (ii) the approach used in the Current PBR Plan.

Response:

Table C4-18 from FEI's 2014-2018 PBR Application is a high level forecast of Growth capital expenditures that was prepared for a specific purpose as set out in response to BCUC IR 1.41.6.

FortisBC has not produced a Growth capital expenditure or Gross Customer Addition forecast for years 2020 though 2024. Rather, the Application sets out the 2019 Base and mechanism by which Growth capital is proposed to escalate over the term of the MRP.

On page 230 of the FEI PBR Application, FEI provided the following table outlining 16 mains forecasting methodology options which were reviewed. FEI stated that its proposed new method is Option #3 while its past practice was based on Option #8:

Table C4-14: Mains Activity Forecasting Options

Option #1 - 2012 actuals - **use most recent year's actuals** rounded to nearest thousand.
Option #2 - 2011-2012 actuals - 2 year average rounded to nearest thousand.
Option #3 - 2010-2012 actuals - 3 year average rounded to nearest thousand. **(NEW METHOD)**
Option #4 - 2009-2012 actuals - 4 year average rounded to nearest thousand.
Option #5 - 2006-2012 actuals - 7 year average rounded to nearest thousand
Option #6 - use 2012 **ratio of New Mains to Service Additions**
Option #7 - use 2011-2012 actuals - 2 years of New Mains to Service Additions ratio history
Option #8 - use 2010-2012 actuals - 3 years of New Mains to Service Additions ratio history **(HISTORICAL METHOD)**
Option #9 - use 2009-2012 actuals - 4 years of New Mains to Service Additions ratio history
Option #10- use 2006-2012 actuals - 7 years of New Mains to Service Additions ratio history
Option #11 - use 2012 **ratio of New Mains to Gross Customer Additions**
Option #12 - use 2011-2012 actuals - two year ratio of New Mains to Gross Customer Additions
Option #13 - use 2010-2012 actuals - three year ratio of New Mains to Gross Customer Additions
Option #14 - use 2012 **ratio of New Mains to Net Customer Additions**
Option #15 - use 2011-2012 - two year ratio of New Mains to Net Customer Additions
Option #16 - use 2010-2012 - three year ratio of New Mains to Net Customer Additions

41.8 Please confirm, or explain otherwise, that FEI used Option #3 to establish the Base capital for Mains under the Current PBR Plan.

Response:

Confirmed. FEI used Option #3 to establish the Base capital for Growth capital (which includes Mains) under the Current PBR Plan.

41.9 Please clarify if FEI is proposing to continue to use Option #3 for the establishment of Mains Base capital for the MRP.

Response:

FEI is proposing to use Option #3 for the establishment of Base Growth capital for the MRP, consistent with the mains forecasting methodology used to produce the forecasts provided in the 2014-2018 PBR Application.

41.10 If FEI had used Option #8 to determine the Mains Base capital for the Current PBR Plan term, what would the annual and cumulative formula amounts have been? Please provide the supporting calculations.

Response:

Table C4-14 in the FEI 2014-2018 PBR Application outlined the various methods that FEI examined to forecast mains. Based on the method selected (option 3), FEI produced Table C4-16, which is reproduced below.

Table C4-16: Forecast Mains Activities, Unit Costs & Expenditures

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Activities (meters)	109,680	75,000	75,000	75,000	75,000	75,000
Unit Costs ($/meter)	62	72	73	74	76	77
Expenditures (000's)	6,783	5,374	5,462	5,561	5,664	5,798

The first table below calculates the three-year average of metres of mains to service lines. The second table below is an expanded reproduction of Table C4-16 from the FEI 2014-2018 PBR

Application using method 8 as requested in this question and includes the service lines forecast from the FEI 2014-2018 PBR Application and the ratio as calculated in the first table below. As seen below, compared to method 3, using method 8 would have resulted in slightly less funding in 2014, and 2018, and slightly more in 2015, 2016 and 2017.

	2010 Actual	2011 Actual	2012 Actual	Average
Meters of Mains	81,259	79,355	65,411	
Services Lines	9,382	7,958	7,898	
Ratio of Mains to SLA	8.66	9.97	8.28	8.97

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Service Lines		8,051	8,407	8,555	8,444	8,270
Mains to Service Lines Ratio		8.97	8.97	8.97	8.97	8.97
Activities (meters)	109,680	72,231	75,424	76,752	75,756	74,195
Unit Costs ($/meter)	62	72	73	74	76	77
Expenditures (000's)	6,783	5,201	5,506	5,680	5,757	5,713

41.11 In consideration of the large variances between formula and actual mains capital during the Current PBR Plan term, please discuss whether FEI considered different options for establishing the 2019 Base capital for mains, such as any/all of the options listed in Table C4-14 of the FEI PBR Application.

Response:

FEI considered different options for establishing the 2019 Base capital for mains and its current proposed methodology of Option #3 is consistent with the Current PBR Plan for the reasons outlined in the response to BCUC IR 1.8.13.

41.12 Please explain why FEI has not provided a comparable level of analysis of its proposed approach to determining base growth capital in this Application as was provided in the FEI PBR Application.

Response:

The analysis provided in support of FEI's 2014-2018 PBR Application was in response to a BCUC request from FEI's 2012/13 Revenue Requirement Application to provide other methods for forecasting mains. In the 2014-2018 PBR Application, FEI produced a forecast of mains expenditures for 2014 to 2018 to compare to the funding provided under the proposed Growth capital formula. In this Application, FEI has not provided a forecast of mains because the utility is requesting an inflation-indexed mechanism to fund Growth capital, which is an extension of the Current PBR Plan formula with modifications as described in the Application. Please also refer to the response to BCUC IR 1.41.6.

42.0 Reference: FEI CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.1, pp. C-56 – C-63; FEI PBR Application proceeding, Exhibit

B-1, pp. 227–238

FEI Growth Capital

On page C-61 of the Application, FEI proposes to add $9.146 million to base growth capital for construction price increases. FEI states: "Overall, FEI's analysis of historical volume mix incorporating updated pricing indicates an increase in the average construction price of approximately 13 percent…in 2020 as compared to the 2016-2018 average in aggregate across all of the Growth capital activities."

42.1 Please provide a detailed breakdown of the actual 2014 through 2018 costs comprising (i) new mains activities, (ii) new service activities, (iii) new customer meters activities and (iv) system improvements (DP).

Response:

Please see the detailed breakdown of the actual 2014 through 2018 costs for New Customer Mains, Services, Meters and DP System Improvements in the tables below.

FEI New Customer Mains ($000s)

	2014	2015	2016	2017	2018
New Mains - Distribution Pressure	8,420	13,752	12,823	16,467	24,487
New Mains - Intermediate Pressure	-	0	-	(0)	7
Total New Customer Mains	8,420	13,752	12,823	16,467	24,494

FEI New Customer Services ($000s)

	2014	2015	2016	2017	2018
New Services - Distribution Pressure	16,325	19,410	20,774	22,547	28,675
New Services - Intermediate Pressure	280	47	39	71	106
Stub Services	1,257	1,595	2,091	2,588	3,232
Conversion Services	4,759	5,840	4,849	9,080	15,626
Service Header Laterals	635	741	846	1,113	1,142
Service Headers	1,119	2,041	2,048	2,374	3,681
Vertical Headers	301	373	550	1,208	1,258
Piping to Suites	0	17	49	169	272
Total New Customer Services	24,675	30,064	31,246	39,149	53,993

FEI New Customer Meters ($000s)

	2014	2015	2016	2017	2018
Residential and Commercial Meter sets	756	699	1,368	1,533	1,578
Large Commercial/Industrial Meter sets	827	1,261	2,062	2,394	2,819
Total New Customer Meters	1,583	1,960	3,430	3,927	4,397

FEI DP System Improvements ($000s)

	2014	2015	2016	2017	2018
Region					
Lower Mainland	332	8	4	167	97
Fraser Valley	837	4,124	2,288	2,689	2,014
Interior North	210	267	300	22	0
Interior South	163	383	132	229	97
Vancouver Island	899	942	229	459	2,225
Total DP SI's	2,439	5,723	2,953	3,566	4,433

42.1.1 As part of the above response, please identify the costs attributable in each of the three years (i.e. 2016 through 2018) to the factors described on pages C-61 and C-62 of the Application.

Response:

The main factors that attributed to the Construction price increase of approximately 13 percent were:

1. Contractor Price Increases;
2. Regional Growth Activity;
3. Field Quality Assurance;
4. Testing Installations; and
5. Muster Kit & Material Allocation Impacts.

Of these five factors described on pages C-61 and C-62 of the Application, only two factors, Regional Growth Activity and Muster Kit & Material Allocation Impacts, have had an impact on actual Growth capital expenditures during the 2016-2018 period. The remaining factors relate to cost increases known or anticipated during the 2019 through 2024 period.

The costs attributable in each of the three years (2016-2018) to Muster Kit & Material Allocation Impacts and Regional Growth Activity are outlined below.

Muster Kit & Material Allocation Impacts

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 2018 to better reflect the actual cost for the materials used in an average service installation. The total incremental impact to New Customer Services represents an increase of approximately $0.9 million and $1.3 million in 2018 and 2019, respectively. 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 total incremental impact to New Customer Mains is a decrease of approximately $0.6 million each year in 2018 and 2019. The net impact of the changes is an increase of 1 percent to the 2019 Base Growth capital.

In the course of responding to this information request, FEI notes an error on page C-62 Line 29 of the Application. "The muster kit material charge for services and mains was increased in 2017" should be revised to "2018". The new prices were effective March of 2018, which were prorated accordingly in calculating the cost impact for both New Customer Services and Mains. This error will be corrected in an Errata to be filed in the near future.

Regional Growth Activity

Please refer to the response to BCUC IR 1.8.12 for a breakdown of costs attributable to regional growth activity in each of the three years 2016 through 2018.

On page C-61 of the Application, FEI states the following regarding Contractor Price Increases:

> 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 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.

42.2 Please explain if FEI competitively bids mains and services contracts each year (i.e. if new terms and pricing are competitively bid each year).

Response:

FEI does not competitively bid mains and services contracts each year. The largest contract was previously in place for over five years before being competitively bid in the fall of 2018. Please also refer to the responses to BCUC IR 1.42.3 and 1.42.3.1.

42.3 Does FEI anticipate that it will competitively bid new mains and services contracts during the proposed MRP term? If yes, please indicate how many times this is likely to occur during the MRP term.

Response:

Mains and Services contracts have been awarded on a three-year term starting January 1, 2019, with two options to renew for two years each. FEI will review and consider Mains and Services prices against market conditions, contractor performance, and other strategic considerations leading up to the end of the first term before renewing.

42.3.1 What is the likelihood that the results of the competitive bidding during the proposed MRP term would lead to lower contractor pricing due to changes in the market or other conditions? Please discuss.

Response:

FEI is unable to predict whether the results of future competitive bidding during the proposed MRP term would lead to lower contractor pricing due to changes in the market or other conditions. However, given FEI's recent competitive bid process for mains and services contracts, it is unlikely to see lower contractor pricing. Factors that could affect the Mains and Services contract pricing include: labour market shortages or surpluses in the Western Canadian construction industry, cost of materials supplied by contractors (such as asphalt, aggregates etc.), changes to scope of work assigned to the contractor, changes to FEI or

municipal/provincial/federal regulations or standards requirements, and the number of contractors interested and able to take on the work.

42.3.2 If FEI does anticipate that it will competitively bid new mains and services contracts during the proposed MRP term, explain whether FEI proposes to adjust the Growth Capital Base Unit Cost according to changes in the contractor prices and if so, when FEI would anticipate applying any adjustments.

Response:

FEI does not anticipate applying any adjustments to the proposed Growth capital Base unit cost during the MRP term.

42.4 Please provide the actual 2014 through 2018 pricing and unit costs for mains and services compared to the new pricing and unit costs in place for 2019.

Response:

The 2014 through 2018 actual unit cost and 2019 proposed unit cost for mains and services is outlined in Table C3-1 on Page C-58 and Table C-3-3 on Page C-61 of the Application.

Please refer to Confidential Attachment 42.4 for the requested Excel files containing actual 2014-2018 pricing and new 2019 pricing for mains and services contracts. The 2018 pricing is representative of the entire 2014 – 2018 period as it was limited to increases of 90 percent of CPI during that period.

Attachment 42.4 is being filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. FEI requests confidentiality of the Excel file contained in Attachment 42.4 because it contains commercially sensitive information, the public release of which could compromise FEI's competitive procurement of these services. Confidential Attachment 42.4 is being filed with the BCUC under separate cover and can be made available to registered parties upon providing a signed form of Confidentiality Declaration and Undertaking acceptable to the BCUC.

42.5 Please clarify if the adjustment for new contractor pricing proposed to be added to base growth capital equals the new contractor pricing for 2019 or if further adjustments were made.

Response:

The adjustment for new contractor pricing proposed to be added to the Base Growth capital equals the new contractor pricing for 2019 and no further adjustments were made.

42.5.1 If further adjustments were made, please clarify how these were determined and please provide the unit cost increase which would have resulted had only the new contractor pricing been included as the adjustment.

Response:

Please refer to the response to BCUC IR 1.42.5.

On pages C-61 and C-62 of the Application, FEI states the following:

> 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…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)…

42.6 Please clarify if the statement on page C-61 of the Application "taking into consideration historical regional allocations of new services" regarding contractor price increases refers to the increased growth activities on Vancouver Island.

Response:

The statement "taking into consideration historical regional allocations of new services" refers to the fact that historical allocations of services between Vancouver Island and the other regions in FEI's service territory were used in analyzing the new contractor pricing.

42.7 Please provide the percentage allocation of new services activities to each applicable region for actual years 2014 through 2018 and projected 2019.

Response:

The percentages provided on pages C-61 and C-62 of the Application are based on the total Growth capital expenditures related to each region. FEI provides a breakdown of Growth capital by region for the years 2014 through 2018 and projected for 2019. FEI used 2019 actuals as at April 30 to derive its projection for the remainder of the year.

Region	2014 A	2015 A	2016 A	2017 A	2018 A	2019 P
Fraser Valley	24%	25%	27%	22%	25%	28%
Interior South	13%	13%	13%	14%	15%	11%
Interior North	6%	7%	8%	6%	5%	3%
Metro	26%	25%	22%	23%	20%	21%
Vancouver Island	26%	25%	25%	31%	31%	35%
Not Assigned	5%	6%	5%	5%	5%	1%
Total	100%	100%	100%	100%	100%	100%

On page C-62 of the Application, FEI states that it is "conducting increased field audits of Growth capital construction to continue to ensure quality requirements are met and to maintain documentation and records quality."

42.8 Please provide the annual number of field audits of Growth capital construction performed during the Current PBR Plan term and provide the expected number of annual field audits to be performed during the proposed MRP.

Response:

FEI does not track completed audits by expenditure program. However, the total number of field audits completed for O&M, Growth, and Sustainment capital during the Current PBR Plan term are as follows:

2014	2015	2016	2017	2018
2,648	2,653	5,039	5,486	5,626

FEI estimates that the number of field audits related to Growth capital is expected to increase by approximately 700 per year.

42.9 Please provide a detailed breakdown and description of the field audit costs incurred each year during the Current PBR Plan term and a detailed breakdown and description of the incremental costs proposed to be added to Base Growth Capital.

Response:

FEI cannot provide a detailed breakdown and description of the field audit costs incurred each year during the Current PBR Plan term as FEI does not track field audit costs separately within management costs. The incremental cost proposed to be added to Base Growth capital is $1.8 million for the addition of nine full time equivalents to oversee the program to continue to ensure quality requirements are met and to maintain documentation and records quality.

42.10 Please provide the amount of the construction price increase of $9.146 million attributable to: (i) contractor price increases; (ii) regional growth activity; (iii) field quality assurance; and (iv) testing installations.

Response:

The amount of the construction price increase of $9.146 million attributable to each of the above factors is provided in the table below.

Description	% Price Increase	Price Increase ($000s)
Contractor Price Increases	8.7%	$ 6,090
Regional Growth Activity	0.9%	$ 597
Field Qualtiy Assurance	2.2%	$ 1,515
Testing Installations	1.3%	$ 943
Total	13.1%	$ 9,146

42.11 Please explain why these incremental costs, and particularly increased costs associated with field quality assurance and testing installations, are not able to be accommodated within the unadjusted unit cost growth capital.

Response:

FEI's objective is to determine an appropriate starting point for Growth capital unit costs for the proposed MRP term. To do so, FEI needs to include all known and measurable adjustments to the base in order establish an appropriate starting point. Accordingly, these incremental costs are an appropriate addition to the Growth capital Base unit cost and should not be accommodated within the unadjusted unit cost Growth capital. Moreover, the incremental costs proposed, including those related to conducting field audits and maintaining documents and records, relate to prudent capital expenditures that are required to ensure the safe and efficient installation of new services. FEI has not identified any offsetting efficiencies for the increased costs associated with field quality assurance, and is not able to accommodate these costs within the unadjusted Growth capital unit cost.

On page C-62 of the Application, FEI states the following:

> 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…The net impact of the changes is an increase of 1 percent ($642 thousand) on average Growth expenditures.

42.12 Please provide the actual muster kit materials charges for services and for mains in each of 2014 through 2018 and the projected amount for 2019.

Response:

Actual muster kit material charges for New Customer Services and Mains in the 2014-2019 period are provided in the table below. FEI used 2019 actuals as at May 31 to derive its projection for the remainder of the year.

Muster Kit Material Charges – New Customer Mains and Services ($000's)

	2014	2015	2016	2017	2018	2019
New Customer Mains	134	147	123	190	261	231
New Customer Services	1,097	1,229	1,209	1,576	3,256	3,161
Total	1,231	1,376	1,332	1,766	3,516	3,391

42.13 Please provide the formula amount for 2019 (before proposed adjustments) for each of the mains and services muster kit materials.

Response:

FEI's formula capital spending is determined at the levels of Growth capital and Sustainment/Other capital and is not further disaggregated. Therefore, FEI cannot provide a formula amount specifically for each of the mains and services muster kit materials. Please also refer to the response to BCUC IR 1.42.1.1 for more details on the incremental cost of mains and service muster kit materials.

42.14 Please explain whether FEI anticipates further changes to the muster kit materials charges during the proposed MRP, and if so, whether these changes could result in net decreases to the materials charges.

Response:

FEI regularly reviews muster materials charges and makes adjustments if changes are warranted. FEI has not historically seen decreases to the cost of materials and therefore does not anticipate reduced material costs over the MRP period.

42.15 Given that the changes to materials charges are reflected in two of the three years used in the three-year average base growth capital amount, please explain why it is not reasonable for FEI to manage the cost pressures created by the lower charges in 2016 during the MRP term.

Response:

As noted in FEI's response to BCUC IR 1.42.1.1, the muster kit material charge for services and mains was increased effective March 2018 and the new prices were prorated accordingly in calculating the cost impact for both New Customer Services and Mains in 2018. The change did not have a material impact on the three-year (2016-2018) average costs and therefore should be considered incremental to the 2019 Growth capital base. FEI has not identified any offsetting efficiencies for capital expenditures related to the muster kit material charge and material allocation impact. These changes were made as a result of detailed usage analysis to better reflect the actual cost for the materials used in an average main or service installation.

43.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-1-1, Appendix B8-1, pp. 8–9

Increased In-line Inspection Activity

On page 8 of Appendix B8-1 of the Application, FEI provides Table A:B8-1-4:

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

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

Further on pages 8 to 9 of Appendix B8-1, FEI states the following:

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

43.1 Please discuss the CSA Z662-15's requirements for in-line inspections and explain whether FEI is in compliance with the requirements of the standard.

Response:

FEI's in-line inspection activities are required for FEI's compliance to relevant standards and regulation (including the CSA Z662-15 standard), and FEI is currently in compliance with the in-line inspection requirements of the CSA Z662-15 standard.

In consideration of factors such as standards (e.g., CSA Z662-15 excerpts below), regulations (e.g., the requirement to "prevent spillage" from section 37 (1) (a) of the Oil and Gas Activities Act), industry practice, and technology availability, in-line inspection is the appropriate technique for monitoring the effectiveness of FEI's corrosion control program and for mitigating related hazards for transmission pipelines (i.e., operating at 30 percent SMYS or above) of NPS 6 and greater. As such, FEI also notes that its Application for the Inland Gas Upgrade (IGU) Project is to maintain compliance with FEI's legal and regulatory obligations related to external corrosion management and in-line inspection.

In the table below, FEI has excerpted what it believes are the most relevant CSA Z662 sections pertaining to in-line inspection. The legal and regulatory provisions applicable to FEI's gas system assets are typically goal-oriented rather than prescriptive in nature. In other words, the requirements of pipeline operators are typically expressed as outcomes to be achieved rather than as descriptions of how to achieve those outcomes. This is true with respect to the CSA Z662-15's requirements for in-line inspections.

CSA Z662-15 excerpt
CSA Z662-15, Clause 9.9.6 states: "Techniques (e.g., the use of internal and external inspection equipment) to monitor the effectiveness of the corrosion control program shall be considered." (Source: Clause 9.9.6, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association) [45] CSA Z662-15, Clause 10.3.1 states: "The pipeline system integrity management program required by Clause 3.2 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data." (Source: Clause 10.3.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[46]

[45] With the permission of Canadian Standards Association, (operating as "CSA Group"), 178 Rexdale Blvd., Toronto, ON, M9W 1R3, material is reproduced from CSA Group's standard **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. This material is not the complete and official position of CSA Group on the referenced subject, which is represented solely by the Standard in its entirety. While use of the material has been authorized, CSA Group is not responsible for the manner in which the data is presented, nor for any representations and interpretations. No further reproduction is permitted. For more information or to purchase standard(s) from CSA Group, please visit store.csagroup.org or call 1-800-463-6727.

[46] Ibid.

CSA Z662-15 excerpt

CSA Z662-15, Clause N.8.3 b) states:

"Where hazards that might lead to a failure or damage incidents are identified, the operating company shall

b) implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions, taking into consideration the options specified in Clause N.10." (see relevant excerpt from Clause N.10 below)

(Source: Clause N.8.3), **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association) [47]

CSA Z662-15, Clause N.10.3 h) states:

"N.10.3 Imperfections

The options that may be used to reduce the frequency of failure and damage incidents associated with imperfections (e.g., metal loss, cracking, and material, manufacturing, and construction defects) include the following, as applicable:

[…]

h) in-line inspection programs;

[…]."

(Source: Clause N.10.3, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[48]

43.2 Please explain the variances in capital expenditures for "Increased in-line inspection activity" for the Current PBR period.

Response:

The drivers resulting in higher expenditures for in-line inspections over the course of the Current PBR Plan term are as follows:

[47] Ibid.
[48] Ibid.

- FEI adopted circumferential magnetic flux leakage technology for all in-line inspected pipelines (as discussed in the response to BCUC IR 1.9.9.2 in the FEI Annual Review for 2017 Rates proceeding; a copy of that response is provided below);

> 9.0 Reference: OVERVIEW OF CAPITAL EXPENDITURES
>
> Exhibit B-2: Section 1.4.4.1, pp. 8–9; Section 1.4.4.3, pp. 12–13
>
> Capital spending results
>
> On pages 8 and 9 of the Application, FEI describes seven contributing factors to the capital cost pressures:
>
> 1. The addition of certain larger industrial mains where the cost significantly exceeded the average customer addition cost that was contemplated under the formula, but that had incremental revenues attached to them and therefore passed the main extension test;
> 2. Capital costs required to carry out the Regionalization Initiative discussed above;
> 3. The installation of Jomar valves on meter sets to allow for meters to be exchanged without turning off gas to the residence;
> 4. Increased in-line inspection activity required to maintain alignment with evolving industry practice;
> 5. Unanticipated system improvements and new stations to supply gas to large new customers;
> 6. Integrity related capital for Burns Bog pipeline stress relief; and
> 7. Pressures from the increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.
>
> 9.9.2 Could the costs associated with the evolving industry practice have been foreseen when the PBR plan was originally put in place? Please explain why or why not.
>
> Response:
>
> As explained in the response to BCUC IR 1.9.8, whether or not the costs could have been foreseen is not a relevant consideration.

However, the increased in-line inspection activity could not have been foreseen at the time the PBR plan was put in place because FEI had not yet evaluated the technology for use. Late in 2013, FEI applied the circumferential magnetic flux leakage in-line inspection technology in a selected pipeline to evaluate the ability to detect longitudinally-oriented features. Early results obtained by this incremental technology provided material improvements to FEI's integrity management capabilities, leading to its subsequent adoption for all in-line inspected pipelines.

- FEI's re-runs of geometry and standard magnetic flux leakage tools are now planned on a maximum 7-year interval. The increased frequency is consistent with industry practice and provides increased confidence in failure prevention; and
- FEI increased the number of transmission pipelines subject to in-line inspection. Please refer to the response to BCUC IR 1.7.1 in the IGU CPCN Application proceeding (a copy of which is provided below) for a table of projects related to enhancing ILI capabilities on CTS pipelines that were executed during the Current PBR Plan term.

7.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Sections 3.4, 4.2.5, pp. 20, 31;

2019 Annual Review, Exhibit B-2, Appendix C4, p. 10; Exhibit B-3, BCUC IR 21.9

Integrity Management Program

On page 20 of the Application, FEI states that it has a comprehensive IMP as required by the BC OGC.

On page 10 of Appendix C4 to the application in the 2019 Annual Review, FEI stated that it "needs to continue to enhance its Integrity Management Program to manage aging infrastructure, meet the CSA Z662-15 standard, and adopt industry practices deemed appropriate to FEI's system."

In response to BCUC IR 21.9 in the 2019 Annual Review, FEI stated the following:

> The particular enhancements that are discussed [in Appendix C4], which pertain to the time period covered by Table C4-4 (i.e. 2014-2018), are unchanged from those that were discussed in response to BCUC IR 1.9.11 in the FEI Annual Review for 2017 Delivery Rates proceeding. At that time, FEI stated that the changes to its in-line inspection activity that were resulting in higher costs were as follows:
>
> …

- FEI increased the number of transmission pipelines subject to in-line inspection. As an example, FEI performed initial baseline in-line inspections for a number of pipeline segments in the Lower Mainland. In addition to the in-line inspection costs, capital expenditures were incurred for retrofits to enable the loading/unloading and passage of the tools…

…FEI is currently forecasting three pipeline segments for crack-detection in-line inspection in 2019, pending the results of front-end engineering design currently in progress to evaluate the timing and feasibility. It is not currently confirmed that the system modifications to manage tool speed within these pipelines, to accommodate tool length impacts on ILI operations, and to provide the capability to reduce the operating pressure of these pipelines for extended time periods without impacting customers will be feasible to implement in time to allow 2019 inspections to be carried out.

On page 31 of the Application, FEI states: "The ILI alternative requires retrofitting an existing pipeline to accommodate its inspection by removing any obstructions that may impede the clear passage of the ILI tool."

7.1 Please explain if, during FEI's 2014-2019 Performance Based Ratemaking (PBR) Plan Term, FEI has incurred sustainment capital expenditures as part of its annual formula capital spending on any transmission laterals to either (1) retrofit the lateral(s) to provide ILI capability; (2) construct pressure regulating stations; or (3) replace the lateral(s) with new pipe.

Response:

This response also addresses BCUC IRs 1.7.1.1, 1.7.1.2 and 1.7.2.

During the 2014-2019 PBR term, FEI did not incur Sustainment capital expenditures on any transmission laterals to (1) retrofit the lateral to provide ILI capability; (2) construct pressure regulating stations for the purpose of reducing operating pressure in a pipeline for an extended period of time; or (3) replace the lateral with new pipe. Neither has FEI included any of the capital activities on the 29 Transmission Laterals in its forecast of Sustainment capital expenditures in its 2020-2024 Multi-Year Rate Plan, which will be the relevant rate setting framework during the time period that the IGU Project will be undertaken. FEI's proposed activities to address the potential for rupture due to corrosion of smaller diameter laterals are not currently included within FEI's Sustainment capital activities and have therefore been brought forward to the BCUC for approval as a single CPCN in the Application.

The activities described in the preamble above, from FEI's response to BCUC IR 1.21.9 in the 2019 Annual Review for Rates, were undertaken to allow the inspection of larger diameter mainline pipelines in the Coastal Transmission System (CTS) in alignment with the scope of FEI's existing ILI program on the Mainland which has been primarily applied to larger diameter mainline pipelines. In contrast, the work proposed in the Application applies to smaller diameter transmission laterals that have not historically been subject to ILI, or alternate solutions like PRS and PLR that would alleviate the need for ILI. After the IGU Project is complete, future costs associated with ILI, pipeline upgrades, or pressure regulating station upgrades on the 29 Transmission Laterals will form part of FEI's Sustainment capital.

The projects related to enhancing ILI capabilities on CTS pipelines that were executed during the PBR term are described further in the table below.

Pipeline	Project Description	2014-2019 YTD Expenditure	Project Construction Year
Noons Creek to Eagle Mountain 610	Installation of pig barrels at either end of pipeline to allow ILI	$1.9 million	2014
Cape Horn to Burrard 508	Installation of additional pig barrels to create 2 inspection segments in order to reduce impact to BC Hydro during ILI	$3.3 million	2014
Nichol to Port Mann 610	Installation of pig barrels at either end of pipeline to allow ILI	$2.4 million	2015
Port Mann To Cape Horn 914	Installation of pig barrels at either end to allow ILI	$5.0 million	2015

FEI also constructs pressure regulating stations (TP/IP or TP/DP) that are used to reduce pressure for distribution to customers on a regular basis as part of Sustainment capital. The pressure regulating stations as part of the IGU Project are required for a new purpose (to reduce the operating pressure of the pipeline to mitigate potential for pipeline rupture) that have not been part of FEI's regular Sustainment capital activities to date.

Fluctuations in expenditures from one year to another during the Current PBR Plan term were primarily due to the following factors:

- Delay of a planned pilot inspection with crack-detection in-line inspection technology (i.e., EMAT, or Electro-Magnetic Acoustic Transducer) on one or more pipelines in the

Coastal Transmission System. The inspection was delayed due the significant complexities associated with running EMAT tools within FEI's transmission pipelines, including system modifications that must be completed in advance.

- FEI's adoption of pipeline-specific in-line inspection frequencies ranging from five to seven years can result in some years having a higher number of inspections than others.
- Co-ordination of runs on common-diameter pipelines to reduce tool mobilization costs.

43.2.1 Please discuss why in-line inspection activities could not be re-prioritized.

Response:

The management of FEI's capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. FEI reprioritizes capital spending as part of its routine management of the capital portfolio and has done so in prior years to accommodate unforeseen events and work, and to mitigate in part some of the pressures seen during the Current PBR Plan term. However, projects that provide higher value, or that are time-sensitive, are not suitable for reprioritization to future years.

FEI's in-line inspection activities are high-value and time-sensitive in that these inspections and subsequent integrity digs materially impact FEI's capability to prevent failures of its transmission pipelines and directly support the safe and reliable operation of these pipelines. In-line inspection mitigates time-dependent threats such as external corrosion. As such, deferral is material and the scheduling of this activity is considered time-sensitive. FEI's in-line inspection activities are also required to:

1. Maintain compliance with regulations and standards (please refer to the response to BCUC IR 1.43.1); and
2. Maintain alignment with industry standard practice. FEI considers it necessary to continually improve its practices in alignment with industry practice. The following is an excerpt from a whitepaper recently published by an independent, expert pipeline risk consultant, JANA Corporation:

> For industries where there are potential hazards that can impact the public, such as the gas pipeline industry, Industry Standard Practice (ISP) becomes a prudent benchmark for pipeline operators and their regulators.

> Operators are otherwise at risk of being found negligent if lawsuits result from an accident. [49]

For the reasons discussed above, it is not appropriate for FEI to reprioritize its in-line inspection activities to future years.

[49] http://www.janatechnology.com/integrating-qra-outputs-into-pipeline-integrity-management-decision-making.

44.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-1-1, Appendix B8-1, p. 9

Ashcroft Lateral Pipeline Replacement Due to Flood Erosion

On page 9 of Appendix B8-1, FEI states the following:

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

44.1 Please confirm, or otherwise explain, whether the costs for the additional three sites planned for remediation in 2019 are included in the cumulative cost of $3.320 million provided in Table A:B8-1-4.

Response:

FEI confirms that the additional three sites planned for remediation in 2019 on the Ashcroft Lateral are included in the cumulative cost of $3.320 million provided in Table A:B8-1-4. The remaining planned expenditures and construction year of the projects is provided below.

Project Name	Construction Year	2019P	2020P
ASHLTL88 Clemes Creek kP3.2	2019	0.284	-
ASHLTL88 Cache Creek kP25.6	2018	0.002	-
ASHLTL88 kP24.96 Cache Creek Encroachment	2019	0.143	-
ASHLTL88 kP24.4 Cache Creek Avulsion	2018	0.002	-
AshcroftLTL60 kP35.69 Bonaparte River	2019	0.312	0.002
Total		**0.743**	**0.002**

44.1.1 If not confirmed, please provide the anticipated capital expenditures required to complete the project and the timelines for completion.

Response:

Please refer to the response to BCUC IR 1.44.1.

45.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-1-1, Appendix B8-1, pp. 10–11

Projects Planned to be Undertaken Outside of Current PBR Term

On page 10 of Appendix B8-1 of the Application, FEI states the following:

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

45.1 Please discuss in detail FEI's planning process for projects or programs in the Sustainment or Other Capital categories during the Current PBR Plan term. As part of this response, please explain how FEI managed its capital expenditures without a comprehensive listing of projects that have been delayed, rescheduled, cancelled or added against what was anticipated when the formula was developed.

Response:

Although the Base capital amount and annual formula adjustments were not derived from a list of future capital projects FEI planned to undertake each year during the Current PBR Plan term, FEI does maintain a current inventory of asset needs that was used each year during the Current PBR Plan term to develop a capital plan consisting of identified projects and programs. The forecast provided in the FEI 2014-2019 PBR Application represented a current view of the asset needs when the Application was submitted in 2013.

Prior to each year of the Current PBR Plan term, FEI's planning process consisted of a review of known work, assemblage of necessary work into projects, development of project scopes, preparation of schedules and then prioritizing the projects based on risk and ability to execute the projects in consideration of available resources. The inventory of asset needs was constantly updated with new requests, projects or updated project information. The more time that has passed from the date of the submission in 2013, the less relevant the original forecast became. FEI always uses the most current information it has available to plan its Sustainment and Other Capital work.

Once approved, the capital plan is managed through monthly, or more frequent, forecasting of all projects and programs to provide the expected timing and amount of planned expenditures in comparison to the approved capital budget. By totalling all of the project and program forecasts, FEI is able to forecast expected capital expenditures of projects during the current year as well as for following years.

As stated on page 10 of Appendix B8-1 of the Application, the management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. It is also important to note that all projects and programs consist of phased expenditures often three to four years in length. When a project is delayed or rescheduled it is often the subsequent phases of a project that are delayed or rescheduled, not the entire project, and activity continues on the project but at a different level. This results in a revised forecast for the project, which either frees up capital funds and resources for added, unplanned projects or necessitates a re-evaluation of other projects to determine if they should be delayed in favour of the more critical or time sensitive project.

On page 11 of Appendix B8-1, FEI provides Table A:B-1-5 which lists the "larger projects that FEI had identified for execution in the 2014-2018 PBR Plan Application but that have been delayed beyond the Current PBR term":

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

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

45.2 Please confirm, or explain otherwise, whether the projects listed in Table A:B8-1-5 that are anticipated to be delivered during the proposed MRP term will be delivered in the Sustainment or Other Capital categories.

Response:

The projects listed in Table A:B8-1-5 that are anticipated to be delivered during the proposed MRP term will be delivered in the categories indicated in the table below.

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

45.2.1 If not confirmed, please provide the category of capital expenditure under which the projects will be delivered.

Response:

Please refer to the response to BCUC IR 1.45.2.

45.3 Please provide a description of the projects and the estimated capital cost for each project listed in Table A:B8-1-5.

Response:

Please refer to the response to BCUC IR 1.46.3 for the estimated capital cost of each of the projects listed. Descriptions of the projects are as follows:

- Class Location Upgrades: Clause 4.3.2 of CSA Standard Z662, *Oil and gas pipeline systems*, defines limitations on operating stress (safety factor) based on the number of dwellings within 200 m of the pipeline. An increase in the density of dwellings adjacent to a pipeline may result in the class location being changed, leading to a requirement to reduce the operating stress of the pipeline and thus increase the factor of safety. CSA Z662 also requires annual assessments of the class location to recognise and accommodate development near the pipeline. In instances where the class location is changed as a result of development, FEI must change the operating parameters of the pipeline. This may require reducing the operating pressure which leads to a loss of capacity and may limit the ability to meet customer demand. In instances where reducing operating pressure is unacceptable, the impacted section of pipeline must be replaced to meet the required safety factor while maintaining customer supply.
    - Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston – Replace nine segments of pipe to meet safety factor for new class location designation.
    - Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk; and Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks – please refer to the description of the combined CPCN project in Section C3.3.3.5 FEI Southern Crossing Class Location Upgrades on page C-79 of the MRP Application.
- The Tilbury LNG Plant Buildings project includes the upgrade of control and administration buildings to meet current standards and to ensure operability following a significant seismic event. This project has been delayed for a reassessment of business requirements and the site space strategy.
- Distribution Main, Service Renewals and Alterations: Penticton Second Supply – The distribution system in and adjacent to the City of Penticton is presently served by one gate station. The configuration of the distribution piping exiting and heading away from the station is such that a failure of one major branch, for example, from third party damage, will result in the interruption of service to a significant portion of the town. There are approximately 13,000 customers served by the existing station and it is planned that a second gate station be installed along with a large supply main into the central portion of town. This will reduce the likelihood of a single event affecting a majority of the customer base.

- The addition of pipe storage to the Burnaby Operations building has been delayed due to further review of requirements for space strategy.

On page 11 of Appendix B8-1, FEI states the following:

> Information Systems expenditures are categorized under five main areas of focus including infrastructure sustainment, desktop infrastructure sustainment, application sustainment, business technology transformation and business technology enhancements. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. As such, FEI does not have any specific IS projects that have been deferred to outside the Current PBR term.

45.4 Please provide a list, in table form, of the projects included in each of the annual portfolios for the Current PBR Plan term.

Response:

Information Systems' spending is managed in five categories (plus cybersecurity) as mentioned in the preamble. The table below shows the actual expenditures for these categories over the term of the Current PBR Plan.

FEI- In $K	YR 2014	YR 2015	YR 2016	YR 2017	YR 2018
Information Systems Sustainment (PBR =APPLICATION)	$6,534	$6,133	$6,518	$6,697	$4,009
Information Systems Sustainment (PBR =DESKTOP)	$2,420	$875	$1,167	$2,353	$4,297
Application Enhancements (PBR=ENHANCEMENT)	$1,574	$2,328	$3,162	$2,414	$1,764
Information Systems Sustainment (PBR =INFRASTRUCTURE)	$5,879	$2,471	$4,457	$4,282	$4,656
Business Technology Applications (PBR=TRANSFORM)	$6,958	$2,831	$2,334	$6,417	$7,699
Cyber Security			$0	$422	$328
	$23,366	$14,639	$17,638	$22,585	$22,753

FEI notes that three of the five categories in the table above - Application, Desktop, and Infrastructure - relate to programs (as opposed to projects) that are generally based on replacing IS assets at the end of their useful lives (as in the case of desktop computers, switches, servers, storage, etc.). Generally speaking, these programs are comprised of a high number of relatively small items. Similarly, the category of Enhancements generally relates to small projects which seek to make incremental improvements to existing assets including software. These are generally comprised of relatively small expenditures. Thus, the discussion below will focus on these categories at the aggregate level.

Unlike the others four categories, the Transform category relates to larger projects that FEI undertakes and are more appropriately described as projects (as opposed to programs). The analysis below will focus on the larger projects (> $2 million), consistent with the identification of projects in the Application and with the requests in BCUC IRs 1.46.2, 1.46.3 and 1.51.3.

Application, Desktop, Enhancement and Infrastructure Categories

These expenditures were within their respective budgets for all years except 2015 and 2016. Expenditures in 2015 and 2016 were under budget by $5 million and $3 million, respectively, due to overall Company capital constraints. The 2015 Desktop expenditures were lower than other years; however, this was a result of the timing of PC replacements occurring in 2015 versus other years.

Transform Category

A total of 123 distinct projects in this category were completed over the Current PBR Plan term. The 2015 and 2016 Transform expenditures were under budget due to overall Company capital constraints.

The following table identifies the Transform projects over $2 million which were completed over the Current PBR Plan term. Each of the three projects was completed on time and on budget.

Projects - $k	Total	Delivered	OnTime/On Budget
ONLINE APPLICATION BACK OFFICE & FIELD SIMPLIFICATION	$2,148	Y	Y
SAP INTEGRATION PROJECT (PROJECT ONE)	$2,988	Y	Y
ASSET INVESTMENT PLANNING	$2,622	Y	Y

45.4.1 For each project, please identify the following: (i) capital cost; (ii) whether or not the project was delivered; (iii) if the project was delivered, whether it was delivered on-time and within the defined budget; and (iv) for any projects that were not delivered on-time and/or within the defined budget, please provide the time and/or budget variances and a description of the cause(s) of the variances.

Response:

Please refer to the response to BCUC IR 1.45.4.

46.0 Reference: FEI CAPITAL EXPENDITURE FORECAST

Exhibit B-1, Section C3.3.2, pp. C-58, C-63 – C-64; Exhibit B-1-2, Evidentiary Update

Sustainment and Other Capital Overview

On pages C-63 and C-64 FEI provides Tables C3-4 and C3-5 summarizing FEI's Sustainment and Other Capital Expenditures for 2014 to 2019 and 2020 to 2024, respectively.

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**

Table C3-5: FEI Sustainment and Other Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sustainment Capital	110,811	111,530	112,944	117,106	119,663	124,533
Other Capital	42,970	49,770	49,916	46,474	46,403	45,351
Total Capital	153,781	161,300	162,860	163,580	166,066	169,884

46.1 Please provide an update to Tables C3-4 and C3-5, to include a line item entitled "Major Projects", and a line item entitled "Total Capital including Major Projects."

Response:

Please see updates to Tables C3-4 and C3-5 below to include Major Projects. Major Project expenditures agree to the totals provided in the response to BCUC IR 1.49.5.

Capital forecasts relating to Major Project capital expenditures contain known and preliminary information and the figures are expected to change as Major Projects continue to develop and evolve. Since all of these Major Projects will be approved through a separate process, they are not relevant to the requests in this Application.

FEI Sustainment, Other and Major Projects Capital Expenditures 2014-2019 ($000s)

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Sustainment Capital (Gross)	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
Major Projects	143,538	196,728	109,927	195,695	191,241	252,535
Total Capital Including Major Projects	**268,896**	**314,105**	**232,372**	**343,949**	**350,448**	**406,415**

FEI Sustainment, Other and Major Projects Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sustainment Capital (Gross)	110,811	111,530	112,944	117,106	119,663	124,533
Other Capital	42,970	49,770	49,916	46,474	46,403	45,351
Major Projects	213,157	139,277	269,000	373,593	578,958	187,382
Total Capital Including Major Projects	**366,937**	**300,577**	**431,860**	**537,173**	**745,024**	**357,265**

46.2 For the Proposed MRP term, please provide, as a new Appendix, a one-page summary for each project or program with a capital cost of over $2 million. Please include the project name, need, alternatives, benefits, scope, capital cost and accuracy level, construction start date, in-service date, consultation, public interest issues, risks and a description of the project.

Response:

Please refer to Attachment 46.2 for the requested new Appendix containing a summary for each of the identified projects over $2 million in the Sustainment Capital plan. AACE International Recommended Practice for cost estimate classification has been used to communicate accuracy level for each project.

Please also refer to the response to BCUC IR 1.46.5 for a description of FEI's project development methodology and note that projects forecasted for execution two or more years in the future remain subject to scope and cost estimate refinement.

46.3 Please provide a breakdown, in tabular form, of all projects or programs in the Sustainment or Other Capital categories with a capital cost of $2 million or greater that FEI had planned to deliver in the Current PBR Plan. Please include the project or program name, capital cost, anticipated construction start date and in-service date and whether or not the project was delivered in the Current PBR Plan term.

Response:

The table below lists the projects with a capital cost of $2 million or greater that were identified in FEI's 2014-2018 PBR Application as potential projects for execution (note that since the term was later extended to 2019, no 2019 projects were included in the list provided in the PBR Application).

Approved capital spending for the Current PBR Plan was set using a formula based approach based on 2013 approved expenditures. The forecast provided in FEI's 2014-2018 PBR Application was prepared for five years at a high level and provided for reference purposes only. Similarly, the projects over $2 million listed below were in the preliminary stages of development at the time of the FEI's 2014-2018 PBR Application and were provided to demonstrate the type of project that would be executed during the Current PBR Plan term. A number of these projects have had changes to scope and schedule in response to changing conditions or resource constraints.

In the Application, FEI is seeking approval of a forecast of capital expenditures. As such, an additional level of rigour was used in the development of the forecasts provided in the MRP Application. Projects that are currently scheduled to be completed in the latter years of the MRP term are still in early stages of development. To mitigate the uncertainty in the forecast for these projects, FEI has proposed to review its forecast for 2023 and 2024 in its Annual Review for 2023 delivery rates.

	From 2014-2019 PBR Application		Current Status	
Project Name	**Forecast Capital Cost ($millions)**	**Estimated Timing**	**Actual or Forecast Capital Cost ($millions)**	**Estimated Timing**
Class Location Upgrade: 2731m (6 segments) of 1957 vintage 273mm OD Savona Nelson Mainline, East of Oliver	4.1	2014	2.5	Constructed 2014-2015

	From 2014-2019 PBR Application		Current Status	
Project Name	Forecast Capital Cost ($millions)	Estimated Timing	Actual or Forecast Capital Cost ($millions)	Estimated Timing
Class Location Upgrade: 2206m (4 segments) of 1957 vintage 114mm OD Williams Lake Lateral, Williams Lake	3.3	2015	2.5	Constructed 2015
Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston	1.3	2016	2.1	Planned for 2020 - 2021
Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk	2.0	2017	2.2	Planned for 2022
Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks	4.5	2018	3.9	Planned for 2022
Pitt River Pipeline Crossing Replacement, 323mm OD Livingstone to Coquitlam Pipeline, Port Coquitlam & Pitt Meadows	3.5	2016	3.5	Timing TBD. Delayed pending evaluation of pipeline condition and interdependency with other planned projects.
Tilbury LNG: Electrical Equipment Upgrade	2.7	2014	0.9	Completed in 2016 with reduced scope
Tilbury Inlet and Outlet Pipelines Replacement	2.0	2015	0.8	Planned for 2020 with reduced scope
Tilbury LNG: Air Cooler Replacement	3.0	2018	3.1	Timing TBD. Delayed pending long-term strategy for Tilbury LNG Plant.
Distribution Main, Service Renewals and Alterations: Penticton Second Supply – Penticton	2.4	2015	4.3	Planned for 2019-2020.
Pattullo Bridge Crossing Replacement	2.7	2015	28.0	Planned for 2022-2023
The addition of pipe storage to the Burnaby Operations building	2.6	2014	2.6	Timing TBD. Delayed due to further review of requirements for space strategy.

46.4 For any projects or programs in the Sustainment or Other Capital categories that were not delivered in the Current PBR Plan term, please confirm, or otherwise explain, whether the projects or programs will be delivered in the proposed MRP term. If applicable, please provide an update to the capital cost, anticipated construction start date and in-service date.

Response:

Please refer to the response to BCUC IR 1.46.3.

46.4.1 If not confirmed, please explain why the projects or programs will not be delivered in the proposed MRP term and discuss any impacts this may have on FEI's system and customers.

Response:

There are three projects that were identified in the 2014-2018 PBR Application that were not completed and whose estimated timing is uncertain. The three projects are:

- Pitt River Pipeline Crossing Replacement, 323mm OD Livingstone to Coquitlam Pipeline, Port Coquitlam & Pitt Meadows.
- Tilbury LNG: Air Cooler Replacement
- The addition of pipe storage to the Burnaby Operations building

All three projects have interdependencies with other proposed projects and have been delayed to ensure optimization of planning, design, and construction schedules. The impacts of delaying these projects will have minimal impact to FEI's system and customers.

Please also refer to the response to BCUC IR 1.46.3.

46.5 Please explain FEI's methodology for forecasting Sustainment and Other Capital expenditures during the proposed MRP term. Please include a discussion on how FEI prioritizes project and or programs.

Response:

The project lifecycle can vary greatly depending on the complexity and urgency of a project, but FEI's project development and forecasting methodology is generally described as follows:

1. Identification of Needs (3+ years prior to execution) – this is an ongoing process where future asset and/or business needs are identified and documented in the Asset Investment Planning (AIP) system. Needs can be identified by anyone in the company. They are documented and managed through the next stages of development by centralized groups based on asset type.

2. Analyze Need and Develop Solution (2-3 years prior to execution) – if a solution is not evident, alternatives are developed and analyzed. A preferred alternative is recommended along with an AACE Class 4-5 cost estimate for the project.

3. Prioritize (1-2 years prior to execution) – projects are evaluated through the AIP value framework. The portfolio is optimized by scheduling identified and valued projects to achieve greatest overall portfolio value subject to a set of resource constraints. The outcome of the prioritization process is a five-year forecast.

4. Refinement - The forecast is refreshed at least once per year to incorporate newly identified work and updated project forecasts and valuations. As a project approaches its scheduled execution year, improved cost estimates are sought and project schedules are refined.

5. Approval (1 year prior to execution) – Capital plans and proposed budgets are submitted for executive approval once per year in the year prior to execution.

6. Management (during execution) – the management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. FEI will bring forward or delay projects that have some flexibility in timing to manage expenditures within the approved amount.

Please refer to Section C3.2 of the Application for a discussion of how FEI prioritizes projects and programs using the AIP tool.

Please also refer to the response to BCUC IR 1.45.1 for a discussion of how FEI manages its capital plan.

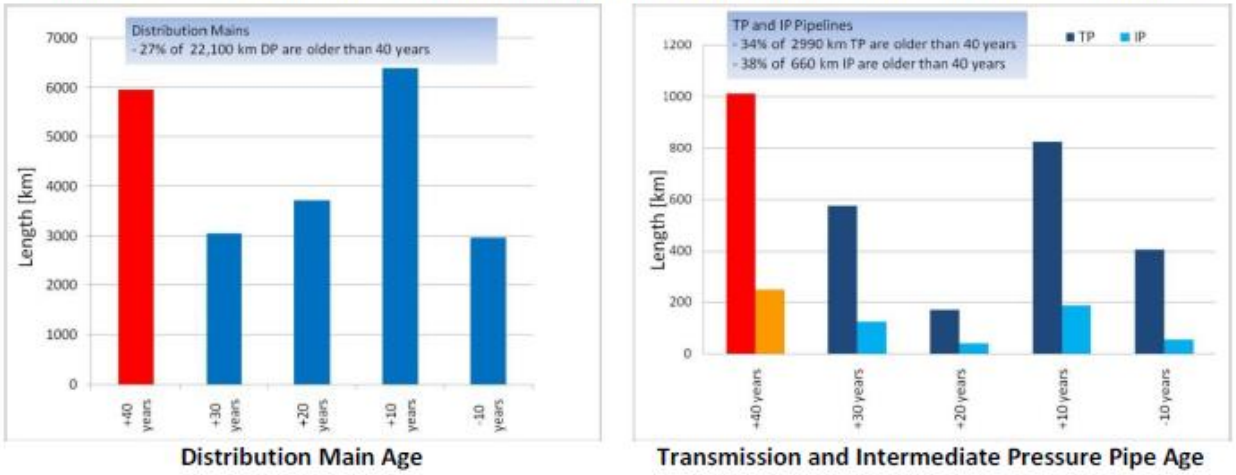
47.0 Reference: FEI CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.2, pp. C-63 – C-72; Exhibit B-1-2, Evidentiary Update; FEI PBR Application proceeding, Exhibit B-1, pp. 211–212

FEI Sustainment Capital

On page 212 of the FEI PBR Application, FEI provided the following information on the proportions of transmission and distribution assets approaching life expectancy:

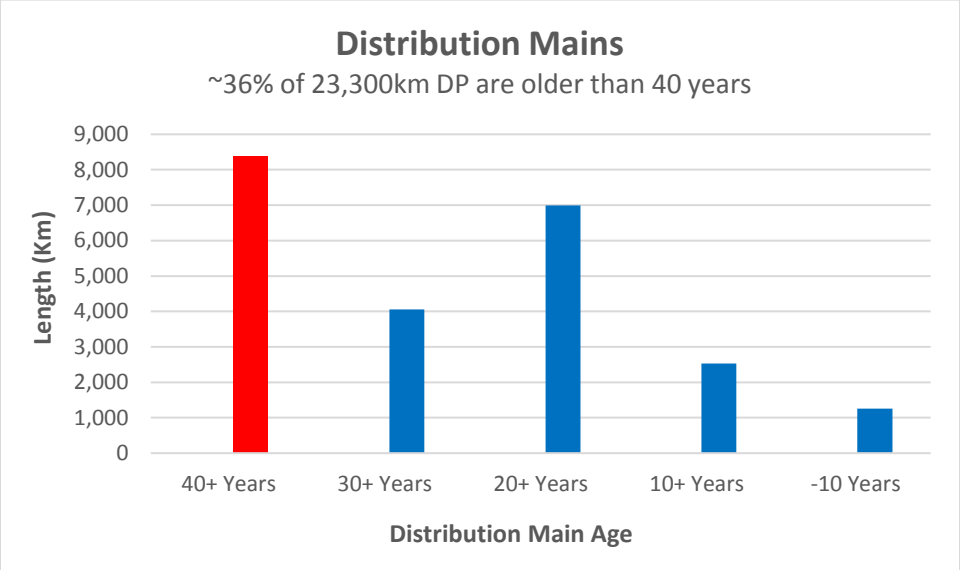
Figure C4-2: Proportions of Transmission and Distribution Approaching Life Expectancy



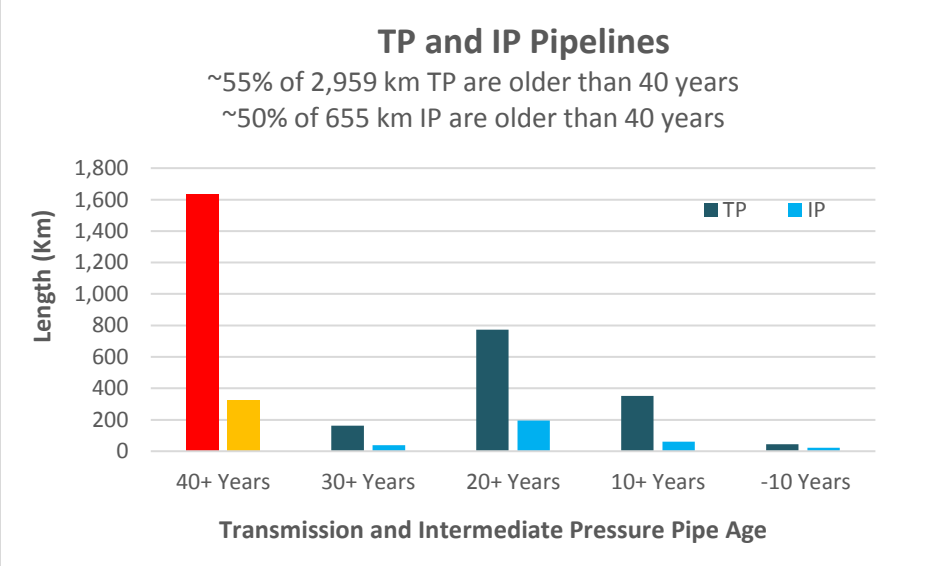
47.1 Please update the above figure for current asset conditions.

Response:

The requested figures are provided below.



1



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6 On page 211 of the FEI PBR Application, FEI provided the following table showing the
7 categories of sustainment capital:

Table C4-5: Forecast Sustainment Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
System Integrity and Reliability Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,224	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains and Service Renewals/Alterations	22,556	25,815	24,433	28,245	34,059	34,304
	78,065	**78,449**	**79,045**	**77,198**	**80,578**	**82,340**

On page C-64 of the Application, FEI provides the following table showing the categories of sustainment capital expenditures during the Current PBR Plan term:

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**

47.2 Please clarify if the types of costs included in the four categories provided in the FEI PBR Application and the costs included in the four categories provided in this Application are the same.

Response:

The names of the categories in Table C3-6 were changed in the Application to match portfolio names used internally to facilitate responses to IRs throughout the MRP term. The table below identifies the equivalent categories from the FEI 2014-2018 PBR Application to the MRP Application.

FEI PBR Application	FEI MRP Application	Comments
Meter Recalls/Exchanges	Customer Measurement	All included types of costs are the same
Transmission System Reinforcements	Transmission System Reliability & Integrity	All included types of costs are the same

FEI PBR Application	FEI MRP Application	Comments
Distribution System Reinforcements	Distribution System Reliability	System Improvements (DP) excluded in current MRP Application. All other included types of costs are the same.
Distribution Mains and Service Renewals/Alterations	Distribution System Integrity	All included types of costs are the same

The types of costs included in the four categories are generally the same between the FEI 2014-2018 PBR Application and the MRP Application. The main exception is the System Improvements (DP), which have been excluded from Distribution System Reliability and included in Growth capital for the proposed MRP. Please refer to the response to BCUC 1.42.1 for a quantification of System Improvement (DP) costs from 2014-2018.

Additionally, in 2016 FEI completed a review of its capital reporting where it developed the portfolio structure described in Appendix B8-2 of the Application. This portfolio structure was implemented in 2017 and resulted in some minor shifts of costs from one of the Sustainment capital categories listed in Table C3-6 to another. The types of costs included in each category have not changed, but some costs changed categories to more accurately reflect the work. The 2014-2019P costs have been restated in the response to BCUC 1.47.5 using the current portfolio breakdown. The variance in the categories resulting from the changes in portfolio structures is shown in the table below.

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Customer Measurement	-	-	-	-	-	-
Transmission System Reliability & Integrity	51	450	17	-	-	-
Distribution System Reliability	(859)	(3,004)	(161)	-	-	-
Distribution System Integrity	808	2,554	143	-	-	-
Total Sustainment Capital	-	-	-	-	-	-

47.2.1 If yes, please explain why FEI has changed the names of the cost categories.

Response:

Please refer to the response to BCUC IR 1.47.2.

47.2.2 If no, please explain and quantify the changes to the cost classifications.

Response:

Please refer to the response to BCUC IR 1.47.2.

47.3 Please confirm, or explain otherwise, whether Table C3-6 includes capital expenditures for distribution system improvements to support customer additions.

Response:

Confirmed. Table C3-6 includes capital expenditures for distribution system improvements to support customer additions, which is consistent with the categorization of those costs during the Current PBR Plan.

47.3.1 If not confirmed, please update Table C3-6 to include distribution system improvements.

Response:

Please refer to the response to BCUC IR 1.47.3.

47.4 Please confirm, or explain otherwise, whether Table C3-7 of the Application excludes capital expenditures for distribution system improvements to support customer additions.

Response:

Confirmed. Table C3-7 of the Application excludes capital expenditures for distribution system improvements to support customer additions.

47.4.1 If confirmed, please update Table C3-7 to include distribution system improvements.

Response:

Table C3-7 has been updated to include distribution system improvements and is provided below. Note that distribution system improvements for the time period shown have been included in Growth capital, which is why they were excluded from the table. The exact timing of distribution system improvements is revised annually based on the updated capacity planning models that incorporate actual and forecast demand. If actual load growth in an area exceeds or lags the forecast, the system improvement will be advanced or delayed accordingly.

	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	16,329	14,259	22,906	18,109	35,950
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	109,417	110,899	116,886	121,384	134,550

In Tables C3-8, C3-9, C3-11 and C3-13 on pages C-65, C-66, C-69 and C-71, respectively, FEI provides the Average 2017-2019P and Forecast 2020 through 2024 cost breakdowns for each category of sustainment capital.

47.5 Please provide the same breakdown of information as is provided in the above-mentioned tables for: (i) Approved (formula) 2014 through 2019; (ii) Actual 2014 through 2018; and (iii) Projected 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FEI is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Actual capital expenditures for 2014 to 2019P are provided in the tables below. As described in the response to BCUC IR 1.47.2, there are some minor differences in the costs included in the four categories of Sustainment Capital from 2014 to 2016 when compared to 2017 onward. The tables below restate the costs consistently with the current portfolio structure. As such, there are some discrepancies between the category totals in the tables below compared to Table C3-6 in the Application.

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Customer Measurement						
Meter Materials	12,952	16,691	18,914	21,824	23,104	19,799
Residential Meter Alteration & Exchange	8,101	7,203	8,032	7,479	7,422	6,939
Small Commercial / Industrial Meter Alteration & Exchange	1,531	1,744	913	700	1,255	935
Large Commercial / Industrial Meter Alteration & Exchange	1,791	2,879	2,280	1,482	1,490	3,164
Total Customer Measurement	24,375	28,516	30,140	31,485	33,271	30,837
Transmission System Reliability & Integrity						
Pipeline Alterations (Applicant 47 and 48)	13,442	17,438	16,005	23,471	10,756	13,445
Pipeline Alterations REC (Applicant 47 and 48)	-	-	-	194	542	1,102
Pipeline Capacity Improvements (Applicant 47 and 48)	0	54	508	102	10,273	1,454
Pipeline Station Alterations (Applicant 50 and 53)	624	1,899	1,279	2,443	5,911	5,543
Transmission System Telemetry Alterations (Applicant 59)	596	913	377	320	2,396	1,880
Compressor Station Alterations (Applicant 50 and 53)	2,268	5,345	6,325	2,380	543	4,163
Compressor Unit Overhauls (Applicant 50 and 53)	-	-	-	2,288	32	378
LNG Plant Alterations (Applicant 54)	1,536	2,000	878	2,040	4,435	7,180
Transmission System Cathodic Protection (Applicant 56)	399	463	447	347	95	432
Pipeline Inspection (Applicant 55)	3,294	2,659	5,917	3,919	4,054	6,635
Pipeline SRW Acquisition (Applicant 49)	(66)	88	21	93	56	90
Transmission System Reliability & Integrity - Total	22,094	30,859	31,755	37,596	39,095	42,301

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Distribution System Reliability						
Distribution Stations Alterations (Applicant 60, 58, 66)	7,522	7,709	8,472	11,979	7,748	9,441
Distribution System Telemetry Alterations (Applicant 59 and	890	751	491	796	1,852	742
Distribution System Capacity Alterations (Applicant 63)	3,812	5,894	3,784	5,112	6,385	2,150
Distribution Stations NEW (Applicant 77)	323	924	911	329	1,011	698
Revelstoke Propane Plant Alterations (Applicant 62)	140	11	1	16	690	38
Distribution Sectioning Valves (Applicant 65)	88	53	394	0	-	20
Distribution System Reliability - Total	12,775	15,342	14,052	18,232	17,686	13,088
Distribution System Integrity						
Main and service alterations (Applicant 74, 76 and 69)	12,937	11,188	9,594	4,793	3,224	4,451
Main and service alterations REC (Applicant 74 and 76)	-	-	-	4,016	4,213	4,444
Main and service renewals (Applicant 74 and 76)	13,297	4,859	5,629	9,927	15,238	10,323
Service hazards mitigation (Applicant 74)	2,602	1,095	1,169	826	1,631	1,988
Distribution System Cathodic Protection (Applicant 56)	1,607	1,087	1,128	1,160	852	1,754
Distribution System Integrity - Total	30,443	18,230	17,521	20,722	25,158	22,960
Total Sustainment Capital	89,688	92,947	93,468	108,036	115,210	109,187

47.6 If in response to IR 47.3 FEI states that Table C3-6 does not include capital expenditures for distribution system improvements to support customer additions, please provide a table, similar to Table C3-13 on page C-71 of the Application, detailing FEI's Distribution System Improvements Capital Expenditures for the Current PBR Plan period.

Response:

Please refer to the response to BCUC IR 1.47.3.

On page C-67 of the Application, FEI states the following:

- **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.

47.7 Please provide details on the multi-year program for valve automation projects, including the total capital cost for the program.

Response:

The Coastal Transmission System (CTS) is located in a densely populated, seismically sensitive part of British Columbia, which poses a higher probability of pipeline damage by third parties or natural ground movements. Due to the higher population density, the consequence associated with a pipeline rupture is greater in the CTS than an equivalent event in a less populated part of the Province. In the event of a pipeline rupture, establishing control of the escaping gas quickly and safely is a critical component of FEI's emergency response.

By automating block valves located at strategic locations throughout the CTS to enable remote control, FEI can partially mitigate the consequences of a transmission pipeline rupture. The ability to shut off gas flow to the impacted segment more quickly reduces the exposure to danger for operations personnel and emergency responders, the quantity of gas vented, and the extent of property damage.

The program started in 2011 and is expected to be complete by 2022 at a total capital cost of $12.088 million. A total of $4.792 million has been incurred to date.

On pages C-67 and C-68 of the Application, FEI describes the forecast capital spending requirements for Transmission System Integrity & Reliability, including in the areas of LNG Plant Alterations and Pipeline Inspection.

47.8 With regard to LNG Plant Alterations and Pipeline Inspection, please provide further details and an annual cost breakdown for the forecast expenditures during the proposed MRP term.

Response:

Annual cost breakdowns of the forecast expenditures during the proposed MRP term for LNG Plant Alterations and Pipeline Inspection are as follows.

LNG Plant Alterations

	2020	2021	2022	2023	2024	Reference
Tilbury LNG Air Cooler Upgrade				3,184		See Table C3-10
5 Year Turnaround at Tilbury LNG Expansion			612	1,873		See Table C3-10
Other	5,006	5,806	6,532	1,522	7,322	
Total – LNG Plant Alterations	5,006	5,806	7,144	6,579	7,322	See Table C3-9

The LNG Plant Alterations portfolio is made up of numerous projects of variable size and scope. The average cost of planned projects is $250 thousand. To balance resource demand and plant downtime in years when larger projects are planned, fewer small projects are scheduled.

Pipeline Inspection

	2020	2021	2022	2023	2024	Reference
Huntingdon to Nichol In Line Inspection				2,760		See Table C3-10
Other	7,382	3,937	3,759	5,015	6,476	
Total – Pipeline Inspection	7,382	3,937	3,759	7,775	6,476	See Table C3-9

The Pipeline Inspection portfolio includes in-line inspection of pipelines and pipeline marine crossing inspections. Both of these activities are completed on a scheduled basis. Forecast costs fluctuate from year to year based on the number, length and diameter of segments planned for inspection.

On page C-68 of the Application, FEI states the following:

- **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.

47.9 Please explain whether the $3.2 million estimated cost for the Air Cooler Upgrade at Tilbury LNG is based on the repair or replacement options. As part of this response, please discuss the likelihood of the costs exceeding $3.2 million if the alternative option is selected.

Response:

The current estimate of $3.2 million for the Air Cooler Upgrade at Tilbury LNG is based on the replacement option; however, further evaluation of alternative solutions is ongoing. Until the completion of the ongoing engineering analysis of project alternatives, FEI is unable to speculate on the technical feasibility of a repair option, or the likelihood that either option would exceed $3.2 million. Upon completion of the evaluation of the alternatives, the alternative providing the lowest cost/highest value will be selected.

On pages C-69 and C-70 of the Application, FEI describes the forecast capital spending requirements for Distribution System Reliability, including the following for Distribution Stations Alterations: "The increased expenditures in these years are caused by capital portfolio optimization to offset expenditures fluctuations in other portfolios."

47.10 Please further explain the statement in the above preamble and provide specific examples of the costs being offset and in which portfolios.

Response:

FEI uses the AIP process described in Section C3.2 of the Application to value and prioritize capital expenditures. Once projects are valued using the AIP value framework, the capital portfolios are optimized using the AIP optimization tool. The optimization process considers all projects and proposes a multi-year plan that delivers the greatest benefit, as measured by the value framework, while meeting any defined constraints. Constraints include resource and financial constraints as well as project constraints. For example, some capital expenditures, such as third party driven work, meter recall, or major inspections have little or no flexibility in timing.

In Sustainment capital planning, the optimization is completed at the top portfolio level, meaning that financial and resource constraints are not placed on the lower level portfolios like Distribution Alterations. By removing constraints at the lower levels of the portfolio hierarchy, the system is able to propose a plan that delivers greater value. The optimization engine is able to choose between a pipeline project, a station project, or a main renewal to achieve the greatest overall portfolio value. As a result, spending levels in the lower level portfolios can and will fluctuate from year to year.

The optimization process is completed at least annually. Once complete, the plan is reviewed by Asset Management, Engineering, Project Management, and Operations stakeholders to

make any manual adjustments necessary in the next 1-2 years of the plan to ensure that the work is able to be executed.

The Distribution Stations Alterations forecast expenditures are higher in 2022 and 2024 by $3.6 million and $1.4 million, respectively, when compared to the average forecast expenditures in the portfolio for the 2020-2024 term. The increased expenditures in Distribution Station Alterations in 2022 is offset in the Main and Service Renewals portfolio ($1.4 million lower than 2020-2024 average) and the Pipeline Inspections portfolio ($2.1 million lower than 2020-2024 average). The increased expenditures in Distribution Station Alterations in 2024 is offset in the Main and Service Renewals portfolio ($2.3 million lower than 2020-2024 average).

FEI provides the following breakdown of Distribution System Reliability expenditures on page C-69 of the Application:

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

FEI further provides the following information on Distribution System Reliability projects with expenditures greater than $2 million on page C-70 of the Application:

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	-	-	-	-

47.11 Please explain why Distribution Stations Alterations capital spending is forecast to be so high for 2022 ($14,131,000 shown in Table C3-11), particularly when considering that Table C3-12 shows only $78,000 of larger project capital spending related to Distribution Stations Alterations in 2022. Please provide a detailed breakdown and description of the expenditures as part of this response.

Response:

FEI actively manages its capital plan at the project level using its AIP tool as described in Section C.3.2 of the Application. Please refer to the response in BCUC IR 1.47.10 that describes why the AIP optimization process results in fluctuations in portfolio expenditure levels from year to year.

For the Distribution Stations Alterations portfolio, it was determined that the maximum value could be realized by executing 27 station alteration projects at a forecasted cost of $12.894 million in 2022 with an average project cost of $478 thousand. As the costs of these 27 station alteration projects are well below the $2 million reporting threshold, they are not identified in Table C3-12.

A total of 82 individual projects make up the $14.131 million identified for 2022. Of these, the 27 projects identified above ($12.894 million) will be in construction, while the remaining 55 projects ($1.237 million) will be for prior year project closeout and design for future projects.

The optimization and review process is completed at least annually to incorporate any newly identified work and any changes to existing project scopes and forecasts. Through this iterative process, it is possible that some of the identified 2022 projects in the Distribution Stations Alterations will be advanced or delayed to account for changing conditions in this portfolio and others.

47.11.1 Please also provide a detailed breakdown and description of the capital spending in 2024 related to Distribution Stations Alterations and explain the higher than average level of spending.

Response:

For the Distribution Stations Alterations portfolio, FEI determined that maximum value could be realized by executing 15 station alteration projects at a forecast cost of $9.144 million in 2024 with an average project cost of $610 thousand. As the cost of these 15 station alteration projects are below the $2 million reporting threshold, they are not identified in Table C3-12.

A total of 85 individual projects make up the $11.940 million identified for 2024. Of these, the 15 projects identified above ($9.144 million) will be in construction, while the remaining 70 projects ($2.795 million) will be for prior year project closeout and design for future projects.

Please refer to the response to BCUC IR 1.47.10 for a description of why the AIP optimization process results in fluctuations in portfolio expenditure levels from year to year. Please also refer to the response to BCUC IR 47.11 for a description of the capital optimization and review process.

47.12 Please provide a detailed breakdown and description of the Distribution Stations NEW expenditures in 2024 and explain why the forecast amount is significantly higher than years' 2021 through 2023.

Response:

For the Distribution Stations NEW expenditures in 2024 the forecast amount is higher than years 2021 through 2023 because, based on expected growth in the Fraser Valley, one new station is required each year from 2021 through 2023, while two new stations are required in 2024. The average cost of each of the new stations in the Fraser Valley is $880 thousand.

47.13 Please provide a detailed breakdown and description of the Revelstoke Propane Plant Alterations spending forecast for 2024 and explain why the forecast expenditures are significantly higher than the other years of the proposed MRP term.

Response:

For the Revelstoke Propane Plant Alterations the spending forecast for 2024 is slightly higher than the prior years due to a $564 thousand project in 2024 to upgrade the backup generator. Under certain conditions the existing backup generator does not have sufficient capacity to supply all of the equipment at the plant. A larger 3 phase generator is proposed that will be located in a new structure.

47.14 Please provide a detailed breakdown and description of the Distribution Sectioning Valves for years' 2021 and 2024 and explain why the spending in these years is forecast to be higher than the other years of the proposed MRP term.

Response:

For the Distribution Sectioning Valves for years 2021 and 2024, the spending in these years is forecast to be higher than the other years of the proposed MRP term for the following reasons:

- A $476 thousand project is planned in 2021 to relocate an isolation valve out from under the south end of the Burrard Street Bridge in Vancouver to a more accessible and safe location. Flow through the bridge crossing will have to be maintained throughout the work and a new fenced enclosure will be required.
- A $53 thousand project is planned in 2024 to install a new valve in the Delta Intermediate Pressure system near 57B Street & 34B Avenue. This valve will allow for the isolation of the sections north and south of this location in the event of an emergency.

On page C-70 of the Application, FEI states the following:

- **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.

47.15 Please discuss the issues with finding a suitable location for the new station.

Response:

A suitable location has not been found for the new station due to unsuccessful discussions with the Municipality, property owners, and developers.

Typically, the new station would be installed adjacent to the existing station, and the existing station subsequently removed. At the current site this is not viable as the municipal road has been widened and there is no location acceptable to both the Municipality and FEI.

Installing the new station further north, within the road allowance of 240 Street was evaluated and proposed to the Municipality; however, the Municipality countered with conditions that stipulated FEI would be required to move the station at an undefined future date when the road was to be widened. These conditions were not acceptable to FEI.

The Owner/Developer of a parcel across 240 Street from the existing station was approached to see if they would sell a small parcel or register an easement for the new station within the proposed development, but they rejected the proposal.

Installation of the new station on a Municipality-owned parcel located West of 240 Street at 100 Avenue was rejected by the Municipality as it did not fit the development plan for the area.

Multiple homeowners were approached along the 102 Avenue corridor to see if any would sell a small parcel or register an easement for the station on their land, but none were receptive.

47.16 Please confirm, or explain otherwise, whether FEI has found a suitable location.

Response:

FEI has not found a suitable location for the new station within the general vicinity of the existing station. Multiple locations within 500m have been evaluated, as described in greater detail in response to BCUC IR 1.47.15.

It is probable that a location could be found approximately 1 km away; however, these locations would require the installation of 1 km of IP pipeline and 1 km of DP main to supply the existing system, resulting in the forecast cost of $2.5 million. In addition, there is a second district station on the tail end of this Intermediate Pressure (IP) system that is approaching its capacity limit and will require an upgrade at a forecast cost of $665 thousand in 2024.

Efforts to find a suitable location for the new station continue; however, another option is being pursued to address the capacity issues at both stations. FEI is currently evaluating the replacement of the IP pipeline that supplies the system with one having a higher operating pressure, which would increase the capacity of the existing stations due to higher station inlet pressures. A high strength plastic pipe is being evaluated for use in this location, and if applicable, it is expected that the replacement of the existing IP pipeline will cost a similar amount to the combined cost of both station upgrades.

47.16.1 If not confirmed, please discuss the locations currently being assessed and the anticipated cost for the project based on each location.

Response:

Please refer to the response in BCUC IR 1.47.16.

48.0 Reference: FEI CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.2, pp. C-63, C-72 – C-76; Exhibit B-1-2, Evidentiary Update; FEI PBR Application proceeding, Exhibit B-1, pp. 207, 245

FEI Other Capital

In Table C-73 on page C-73 of the Application, FEI provides the Average 2017-2019P and Forecast 2020 through 2024 cost breakdowns for Equipment capital expenditures.

48.1 Please provide the same breakdown of information as provided in the above-mentioned table for: (i) Approved (formula) 2014 through 2019; (ii) Actual 2014 through 2018; and (iii) Projected 2019.

Response:

FEI has assumed the question is referring to Table C3-18 on page C-73 of the Application.

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FEI is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

A detailed cost breakdown for Equipment capital expenditures for (ii) Actual 2014 through 2018 and (iii) Projected 2019 is provided in the table below.

FEI Equipment Capital Expenditures 2014-2019 ($000's)

Equipment	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Tools and Equipment	1,923	1,778	1,837	1,703	2,242	3,750
Fleet Services	3,043	3,363	3,927	8,103	11,507	6,600
Measurement Services	756	722	525	519	213	503
Radio Communications	2,521	1,456	1,418	1,983	1,750	1,890
Supply Chain	-	-	-	304	278	413
Total Equipment Capital	8,242	7,319	7,706	12,611	15,990	13,156

FEI provided the following information in Table C4-3 on page 207 of the FEI PBR Application:

Table C4-3: Forecast FEI Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Other						
Biomethane - Interconnect	1,032	3,908	1,100	1,864	1,864	1,864
Equipment	5,840	6,818	7,328	7,127	7,358	6,702
Facilities	4,194	3,904	4,026	4,122	4,269	4,626
IT	20,107	20,105	20,105	20,106	20,102	20,098
Total Other	31,173	34,735	32,560	33,218	33,593	33,289

On pages C-72 and C-73 of the Application, FEI provides the following tables:

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 C3-18: 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

48.2 Please explain in detail why the actual Equipment capital spending during the Current PBR Plan term significantly exceeded what was forecast by FEI in the PBR Application. As part of this response, please provide the same annual breakdown as was provided in Table C3-18 of the Application for actual years 2014 through 2019 (projected) and formula years 2014 through 2019.

Response:

The increased spending in Equipment during the Current PBR Plan term compared to the high level forecast provided in the FEI 2014-2018 PBR Application is primarily due to additional Fleet and Equipment requirements related to growth, and in particular the addition of Operations headcount. The majority of these positions are related to construction crews required to assist with the increasing volume of Growth Capital projects.

Please refer to the response to BCUC IR 1.48.1 for a detailed annual breakdown of Equipment capital spending for the 2014-2019 period and why a formula specific for Equipment capital is not applicable in the Current PBR Plan term.

On page 245 of the FEI PBR Application, FEI provided the following table showing the historical breakdown of IT Capital spending:

Table C4-21: Historical IT Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Projection	2013 Approved
IT Capital					
Businses Technology Transformation	3,655	5,099	2,193	6,300	5,850
Business Technology Enhancements	800	1,085	3,968	4,500	3,150
Infrastructure Sustainment	3,952	4,667	3,931	4,500	4,050
Desktop Infrastructure Sustainment	2,379	1,541	1,407	2,700	2,250
Application Sustainment	1,631	2,112	2,484	3,600	2,700
	12,418	14,503	13,983	21,600	18,000

On page C-75 of the Application, FEI provides the following breakdown of IS Capital expenditures:

Table C3-19: FEI IS Capital Expenditures 2020-2024 ($000s)

IS	Average 2017-2019P	2020	2021	2022	2023	2024
Information Systems Sustainment	12,268	11,758	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	28,308	28,561	28,426	27,500	27,605

48.3 Please reconcile the categories of IT/IS capital provided in the PBR Application to the categories in this Application and explain if there have been any additions or removals of categories since the PBR Application.

Response:

Please see the reconciliation of categories of IS capital provided in FEI's 2014-2018 PBR Application and the MRP Application as outlined below:

FEI PBR (Table C4-21)	FEI MRP (Table C3-19)	Comments
Business Technology Transformation	Business Technology Applications	
Business Technology Enhancements	Application Enhancements	
Infrastructure Sustainment Desktop Sustainment Application Sustainment	Information Systems Sustainment	Combined all sustainment into one category for FEI MRP
	Cybersecurity	New category

48.4 Please provide the same breakdown of information as provided in Table C3-19 of the Application for: (i) Approved (formula) 2014 through 2019; (ii) Actual 2014 through 2018; and (iii) Projected 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FEI is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

A cost breakdown of capital expenditures for (ii) Actual 2014 through 2018 and (iii) Projected 2019 is provided in the table below.

FEI IS Capital Expenditures 2014-2019 ($000's)

IS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Information Systems Sustainment	14,834	9,480	12,142	13,332	12,962	10,567
Application Enhancements	1,574	2,328	3,162	2,414	1,764	1,800
Cybersecurity	-	-	-	422	328	2,900
Business Technology Applications	6,958	2,831	2,334	6,417	7,699	11,250
Total	23,366	14,639	17,638	22,585	22,753	26,517

On page C-63 of the Application, FEI states the following:

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.

48.5 Please discuss any risks to FEI and ratepayers of establishing capital expenditures for Sustainment and Other Capital based on a five-year forecast.

Response:

As explained in Section C3.3.2 of the Application, FEI intends to review its Sustainment and Other capital forecast for 2023 and 2024 in its Annual Review for 2023 delivery rates. The review will allow FEI to account for any material changes to the 2023 and 2024 forecasts that may occur over the 2020 through 2022 period and ask for approval of any material changes. Consequently, the risk of a five-year forecast should be viewed as similar to the risk from a cost of service application that typically includes a two-year capital forecast.

Under a cost of service regime, the earnings difference from capital variances flow to the shareholder. However, as described in the workshop held May 1, 2019 and in materials provided as Exhibit B-2, variances in Sustainment and Other capital forecasts will cause changes in achieved earnings and be shared symmetrically with customers on a 50/50 basis, which reduces the risk to ratepayers and to the Company of any variances.

48.6 Based on FEI's results of historical forecast versus actual sustainment and other capital (both during cost of service periods and PBR periods), please discuss why FEI considers it reasonable for the BCUC to approve a five-year forecast for its sustainment/other capital expenditures.

Response:

Please refer to the response to BCUC IR 1.48.5.

49.0 Reference: FEI CAPITAL EXPENDITURE FORECAST

Exhibit B-1, Section C3.3.3, pp. C-77 – C-80

FEI Major Projects

On page C-77 of the Application, FEI states the following:

> 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.

49.1 For each of the eight Major Projects identified on page C-77 of the Application please provide, as a new Appendix, a one-page summary to include the project name, need, alternatives, benefits, scope, capital cost and accuracy level, construction start date, in-service date, consultation, public interest issues, risks, and a description of the project.

Response:

In this Application, FortisBC is only requesting approval of Regular capital expenditures as identified in the respective five-year capital plans for FEI and FBC. Approval of the Major Projects identified on page C-77 of the Application will most likely be sought by way of a CPCN application. If upon further project development, a Major Project is found not to meet the criteria of a CPCN, it may instead be included in a mid-term MRP update of the capital expenditures forecast. With the exception of the Inland Gas Upgrades Project for which FEI filed a CPCN application on December 17, 2018, these projects are at various stages of development and it is premature to provide details at this time, as they are largely unknown.

Section C3.3.3 includes summaries of the project need, scope and forecast construction timelines. For those projects for which FEI has preliminary cost estimates, please refer to the

response to BCUC IR 1.49.5. Complete details of the information requested will be provided in the respective CPCN applications, consistent with the BCUC's CPCN Application Guidelines.

49.2 Please confirm, or explain otherwise, whether the eight Major Projects identified on page C-77 of the Application represent all of FEI's anticipated Major Projects for the proposed MRP term.

Response:

Not confirmed. The Major Projects identified in the Application are examples of projects that may arise during the term of the proposed MRP. FEI has identified, and is investigating, other projects that FEI may bring forward during the MRP term. At the current preliminary stage of investigation, FEI believes it is premature to identify or discuss projects that may not proceed, and they do not affect the approvals sought in this Application.

49.2.1 If not confirmed, please provide a list of all proposed Major Projects expected during the proposed MRP term.

Response:

Please refer to the response to BCUC IR 1.49.2.

49.2.2 If not confirmed, please provide, as a new Appendix, a one-page summary to include the project name, need, alternatives, benefits, scope, capital cost and accuracy level, construction start date, in-service date, consultation, public interest issues, risks and a description of any additional projects identified.

Response:

Please refer to the response to BCUC IR 1.49.2.

49.3 For each Major Project that FEI intends to deliver during the proposed MRP term, please explain if, in the event that a CPCN is not granted, FEI would proceed with the project.

Response:

Pursuant to Order G-120-15 which set the CPCN threshold at $15 million, FEI is required to file a CPCN application for any of the projects that meet this threshold. Under section 45(1) of the UCA, FEI

> … must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

FEI would not be permitted to proceed with the project without CPCN approval.

49.3.1 If yes, please provide the impact on FEI's forecast Sustainment and Other Capital Expenditures for the proposed MRP term.

Response:

Please refer to the response to BCUC IR 1.49.3.

49.4 Please provide a breakdown, in tabular form, of all Major Projects FEI planned to deliver in the Current PBR Plan term.

Response:

As provided in Section 4.7 (pp. 250-251) of the FEI 2014-2018 PBR Application, below is a table of Major Projects (CPCNs and OICs) FEI listed as being considered at the time of filing, covering the years 2014 through 2018. FEI notes that, consistent with this Application, FEI did

not seek approval of these projects in the FEI 2014-2018 PBR Application, such that the information provided in that proceeding was for additional information purposes only.

Project Name	Description
Huntingdon Station Bypass	Loss of functionality of certain sections of the Huntingdon Station can lead to the complete outage on both the Coastal Transmission System and Vancouver Island systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station, is necessary to reduce the risk of a service outage.
Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station	As a result of operational issues that have been experienced, work has been undertaken over the past several years to stabilize most of the Right of Way in the Burns Bog area through which two transmission pipelines run. There are still sections that remain to be stabilized to mitigate the risk of ground movement and associated pipe damage.
Coastal Transmission System Upgrade Plan	Analysis of the Coastal Transmission System has indicated there are a number of projects that may be required in order to ensure the ongoing safety, integrity, and reliability of the system. This plan includes the following projects: 1. Looping the 610mm OD Nichol to Port Mann Transmission Pipeline with 914mm OD in Surrey; 2. Looping the 610mm OD Nichol to Roebuck Transmission Pipeline with 1067mm OD in Surrey; 3. Replacing and upgrading the 508mm OD Coquitlam to Vancouver Intermediate Pressure Pipeline (the actual size and delivery pressure are still to be determined); and 4. Looping the 508mm OD Cape Horn to Coquitlam Transmission Pipeline with 914mm OD in Coquitlam.
Kingsvale-Oliver Reinforcement Project (KORP)	KORP consists primarily of a 161 km, 24-inch expansion project from Kingsvale to Oliver, BC. The reinforcement would further integrate and expand service using available capacity on Enbridge T-South and FortisBC's Southern Crossing Pipeline.

49.4.1 For each Major Project, please provide the following: (i) approved and actual capital cost; (ii) anticipated construction start date and in-service date; (iii) whether or not the project was delivered; (iv) if the project was delivered, whether it was delivered on-time and within the defined

budget; and (v) for any projects that were not delivered on-time and/or within the defined budget, please provide the time and/or budget variances and a description of the cause(s) of the variances.

Response:

The list of potential major projects provided in the FEI 2014-2018 PBR Application was prepared at a high level and provided for reference purposes only. These projects were in the preliminary stages of development at the time of the FEI 2014-2018 PBR Application and were provided to demonstrate the type of Major Project that may be executed during the Current PBR Plan term. Please refer to the response to BCUC IR 1.49.1 for a discussion of the treatment of Major Projects under the MRP Application. As with the proposed MRP, approval of Major Capital projects was not requested in FEI's 2014-2018 PBR Application.

Project Name	Forecast Capital Cost ($ million)	Actual Capital Cost ($ million)	Anticipated Start Date/In-service Date	Actual In-Service Date	Description of Variances
Huntingdon Station Bypass	$ 8.624	$ 7.004	May 2015/ October 2015	March 2016	Variance primarily due to design simplification and the general contract award for construction at a lower cost than budgeted.
Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station	Not submitted	n/a	To be determined	To be determined	Less development activity around the pipelines has reduced the need to address this matter. Development activity is being monitored. Stabilization would be more cost effective if done at time of adjacent development.
CTS Upgrade Plan (Coquitlam to Vancouver IP Pipeline)	$ 255.244	Project underway	Underway / November 2020	To be determined	Portion in service in 2018. Another phase planned for early 2020 with balance by end of 2020.
CTS Upgrade Plan (TP Loops)	$ 165.679	$ 163.925	Not applicable	December 2017	

Project Name	Forecast Capital Cost ($ million)	Actual Capital Cost ($ million)	Anticipated Start Date/In-service Date	Actual In-Service Date	Description of Variances
Kingsvale-Oliver Reinforcement Project	Not submitted	0	To be determined	To be determined	Project was not delivered during the Current PBR Plan term because justification is still under development.

49.4.2 If a Major Project was not delivered in the Current PBR Plan term, please explain why and explain whether FEI proposes to deliver the project in the proposed MRP term.

Response:

Please refer to the response for BCUC IR 1.49.4.1.

49.5 Please compare the number of Major Projects and the total capital cost of these projects during the Current PBR Plan term to the proposed MRP term. Please provide the information for the Current PBR Plan including and excluding the Tilbury Expansion project.

Response:

Tables 1 and 2 below show the number and cost estimate of anticipated Major Projects (CPCNs or through OIC) that were identified for separate approval at the outset of the Current PBR Plan term and those that FEI has included in the proposed MRP term. The Major Projects listed in the Application are at varying stages of development and forecast costs such that they are preliminary estimates only and they are likely to change (please refer to the response to BCUC IR 1.49.1). When FEI proceeds with a CPCN application for any of the listed projects, it will include scope definition and cost estimates consistent with the CPCN guidelines.

The costs presented below include AFUDC Debt and Equity costs.

Table 1: FEI Major Projects, 2014-2019P

		2014	2015	2016	2017	2018	2019P
1	CPCN Huntingdon Control Station		5,777	628	-	-	-
2	Tilbury 1B Expansion (OIC)	-	-	-	-	1,448	10,797
3	Tilbury LNG Plant (OIC)	141,839	181,233	80,772	50,504	5,691	8,376
4	Lower Mainland System Upgrade (OIC)	1,699	8,449	19,453	115,667	18,568	1,843
5	CPCN LMIPSU		1,269	9,074	29,523	165,534	222,850
6	Inland Gas Upgrades	-	-	-	-	-	6,641
7	Okanagan Capacity Upgrade	-	-	-	-	-	1,028
8	Pattullo Bridge Gas Line Replacement	-	-	-	-	-	1,000
	Total	**143,538**	**196,728**	**109,927**	**195,695**	**191,241**	**252,535**

Table 2: FEI Major Projects, 2020-2024

		2020	2021	2022	2023	2024
1	Eagle Mountain. - Woodfibre Gas Pipeline Project	-	-	-	347,731	-
2	Tilbury 1B Expansion (OIC)	36,667	64,563	1,003	1,062	1,124
3	Tilbury LNG Plant (OIC)	109	17,382	-	-	-
4	CPCN LMIPSU	27,500	-	-	-	-
5	Inland Gas Upgrades	62,217	99,311	93,483	67,377	31,164
6	Transmission Integrity Management Capability	-	25,736	155,933	154,810	155,094
7	Okanagan Capacity Upgrade	4,384	41,909	107,173	7,778	-
8	Pattullo Bridge Gas Line Replacement	8,200	18,600	-	-	-
9	Southern Crossing Class Location Upgrades	200	1,500	16,000	200	-
10	Sun Peaks Conversion	Under Development				
11	Sunshine Coast Capacity Upgrade	Under Development				
12	Advanced Metering Infrastructure	Under Development				
	Total	**139,277**	**269,000**	**373,593**	**578,958**	**187,382**

49.6 Please explain whether any of the Major Projects included in the proposed MRP were originally included in the Current PBR Plan's Sustainment or Other Capital categories.

Response:

Two of the Major Projects listed on page C-77 of the Application were originally included in the 5-year high level estimates that were included in the Current PBR Plan's Sustainment Capital category. None of the projects were included in the 2013 Base Capital that formed the basis for the formula funding that was in place during the Current PBR Plan term.

FEI Pattullo Bridge Gas Line Replacement:

At the time the FEI 2014-2018 PBR Application was filed, Translink had notified FEI of its intention to replace the Pattullo Bridge and that FEI would have to move its gas line by 2015. FEI completed a preliminary high level cost estimate for replacing the existing 508mm OD gas line on the bridge with a new gas line of similar attributes for a cost of approximately $2.7 million. At that time, FEI had preliminary agreement with Translink that it would be permitted to install the gas line on the new bridge. Since that time, MoTI has assumed ownership of the project and has denied approval for the gas line to be placed on the new bridge. FEI is carrying out an alternatives analysis and preliminary cost estimating for several alternatives that include replacing the crossing on the bridge, reinforcing the system north of the Fraser River to support the load in New Westminster without a crossing, or replacing the existing crossing with an HDD crossing. The preferred option will be selected based on the findings of the completed options analysis. Based on the most recent cost estimates for the various options, FEI is expecting to file a CPCN Application.

FEI Southern Crossing Class Location Upgrades:

At the time the FEI 2014-2018 PBR Application was filed, FEI had identified six segments of the Southern Crossing Pipeline that required upgrading due to changes in class location, including the two projects listed below that were mentioned explicitly:

- 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk (2017) – approx. $2 million; and
- 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks (2018) – approx. $4.5 million.

The total estimated expenditure to upgrade the six segments of pipe was below the CPCN threshold. Through the annual class location assessment, additional requirements were identified in 2014 and 2015 due to additional increases in density of dwellings around the Southern Crossing Pipeline. In 2014, seven additional valves were determined to be required to reduce valve spacing to meet regulatory requirements. In 2015, five additional pipe segments were identified for upgrade due to increased dwelling density around the pipeline. This work has been proposed as a single project to improve efficiency and to coordinate and minimize the downtime required on the Southern Crossing Pipeline.

49.6.1 If confirmed, please provide a list of any such projects or programs and provide a rationale for the re-categorization.

Response:

Please refer to the response to BCUC IR 1.49.6.

50.0 Reference: CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.2, pp. C-72 – C-76, C-77, C-106 ;Order G-120-15 dated July 22, 2015, FortisBC-Capital Exclusion Criteria under PBR – Compliance Filing

FEI and FBC Major Projects

On page C-77 of the Application, FEI states: "Major Projects are capital expenditures that do not form part of Regulatory 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."

On page C-106 of the Application, FBC states: "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."

In Order G-120-15 regarding the FortisBC PBR Plan Decisions Capital Exclusion Criteria under PBR, it states the following:

> **NOW THEREFORE** for the attached reasons for decision, pursuant to section 60 of the *Utilities Commission Act*, the Commission orders, for the purpose and duration of the current Performance Based Ratemaking (PBR) Plans for FortisBC Inc. (FBC) and FortisBC Energy Inc. (FEI), that:
>
> 1. FBC's and FEI's PBR materiality thresholds are set at $20 million and $15 million, respectively. These materiality thresholds shall be used to determine whether capital costs are eligible for exclusion from the FBC's and FEI's formula-driven capital spending.
>
> 2. The Certificate of Public Convenience and Necessity (CPCN) dollar threshold will be maintained at $20 million dollars for FBC and increased from $5 to $15 million dollars for FEI However, the Commission may require a CPCN review for projects below this threshold if it finds that pursuant to section 45 of the *Utilities Commission Act* it is in the public interest to do so.

50.1 Please clarify whether FortisBC is proposing, as part of this Application, to continue the currently approved CPCN thresholds for FBC and FEI at $20 million and $15 million, respectively.

Response:

FortisBC is proposing that the approved CPCN thresholds for FBC and FEI continue for the proposed MRP term.

50.2 Please confirm, or explain otherwise, that the determination of a materiality threshold, as provided for in Directive 1 of Order G-120-15, is not relevant under FortisBC's proposed MRPs since only FEI's growth capital is proposed to be subject to formula.

Response:

Confirmed. The Current PBR Plan materiality threshold is no longer relevant. Since the majority of capital expenditures are based on cost of service forecasts, there is no formula capital envelope to which a materiality threshold might be applied. The indexed approach proposed for FEI's Growth capital spending is not amenable to a threshold of the kind used in the Current PBR Plan.

In FortisBC's PBR Decisions Capital Exclusion Criteria Compliance Filing (Capital Exclusion Application), it summarized the CPCN application criteria in place for FEI and FBC prior to the Current PBR Plans.

With regard to FEI, the Capital Exclusion Application stated the following:

> For FEI, the current materiality threshold of $5 million was set through the 2003 Negotiated Settlement Agreement approved by the Commission in Order G-51-03. For capital projects below $5 million that do not require a CPCN application, FEI is deemed to have received a CPCN for those projects pursuant to Subsection 45(2) of the UCA.

With regard to FBC, the Capital Exclusion Application stated the following:

> For FBC, the current materiality threshold of $20 million was approved by Order G-52-05. Additionally, the Commission approved four non-financial or exogenous criteria, each of which is sufficient to subject a capital project to a CPCN application regardless of the value of the project. For capital projects that do not meet these criteria and therefore do not require a CPCN application, FBC is deemed to have received a CPCN pursuant to subsection 45(2) of the UCA. The four non-financial capital exclusion criteria are:
>
> 1. The project is likely to generate significant public concerns; or
> 2. FBC believes for any reason that a CPCN application should proceed; or
> 3. After presentation of a capital plan to FBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application; or
> 4. The Commission deems necessary for a CPCN application regardless of the criteria.

50.3 Please explain if FortisBC is proposing that the CPCN criteria for both FEI and FBC during the proposed MRP term will continue to be based solely on a dollar threshold, similar to the Current PBR Plan term.

Response:

FortisBC is proposing that the CPCN criteria for both FEI and FBC during the proposed MRP term will continue to be based solely on the dollar threshold set by Order G-120-15. A revised Draft Order reflecting this in the approvals sought will be included in an Errata to be filed in the near future.

FortisBC notes, however, that Order G-120-15 states:

> The Certificate of Public Convenience and Necessity (CPCN) dollar threshold will be maintained at $20 million dollars for FBC and increased from $5 to $15 million dollars for FEI. However, the Commission may require a CPCN review for projects below this threshold if it finds that pursuant to section 45 of the Utilities Commission Act it is in the public interest to do so.

The Decision attached to Order G-120-15 similarly states:

> The Commission can require any utility, including FEI and FBC, to apply for a CPCN if it is of the view that there is a significant public interest issue or issues. This responsibility of the Commission arises from the UCA, regardless whether that criterion is specifically enumerated. Therefore, criterion No. 1 and No. 4 are implicit in the legislation and apply equally to FEI and FBC and cannot be set aside.

51.0 Reference: FBC CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4.1, 3.4.2, pp. C-80 – C-106

FBC Capital Expenditure Forecast

On page C-80 of the Application, FortisBC states the following:

> FBC's capital expenditures fall under two main categories: Regular capital and Major Project capital expenditures.
>
> Regular capital expenditures include 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.

On page C-81, FortisBC provides Table C3-20 and Table C3-21:

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: 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

51.1 Please revise Tables C3-20 and C3-21 to include a line item for "Major Projects," and a line item for "Total Capital".

Response:

Please see updates to Tables C3-20 and C3-21 below to include Major Projects. For the 2020-2024 Major Projects, FBC has included only those four projects listed on pages C-106 through C-108 of the Application.

Capital forecasts relating to Major Project capital expenditures contain known and preliminary information and the figures are expected to change as major projects continue to develop and evolve. Since all of these Major Projects will be approved through a separate process, they are not relevant to the requests in this Application.

Table 1: FBC Actual and Projected Capital Expenditures, 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Growth Capital	$ 18,821	$ 21,267	$ 15,456	$ 22,333	$ 24,003	$ 17,519
Sustainment Capital	48,577	27,301	25,645	29,367	28,616	33,227
Other Capital	8,093	8,183	9,307	13,882	11,942	15,225
Total Regular Capital	75,490	56,752	50,408	65,582	64,561	65,971
Major Projects	14,349	23,750	10,758	25,625	23,155	28,162
Total Capital Expenditures	$ 89,839	$ 80,502	$ 61,167	$ 91,207	$ 87,716	$ 94,133

Table 1 above contains a correction to Table C3-20 for the year 2014. Table C3-20 will be corrected in an Errata to be filed in the near future.

Table 2: FBC 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
Major Projects	25,647	27,098	17,695	7,135	-	-
Total Capital Expenditures	$ 91,019	$ 120,622	$ 105,548	$ 89,339	$ 86,220	$ 92,204

51.2 Please revise Table C3-20 to include the formula regular capital expenditures for each of the years' 2014 through 2019 and provide the dollar and percentage variances between formula and actual for year.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed expenditures for the years 2014 through 2019.

51.3 Please provide a breakdown, in tabular form, of all projects or programs in the Regular Capital categories with a capital cost of $2 million or greater that FBC delivered and/or had planned to deliver in the Current PBR Plan term. Please include the project or program name, capital cost, anticipated construction start

date and in-service date and whether or not the project was delivered in the Current PBR Plan term.

Response:

FBC's ongoing Growth, Sustainment and Other capital programs exceed $2 million in expenditures over the term of the Current PBR Plan. These include:

Growth Capital:

- Distribution Small Growth
- Distribution Unplanned Growth
- New Connects

Transmission Sustainment:

- Transmission Lines Condition Assessment
- Transmission Lines Rehabilitation
- Transmission Rights of Way
- Transmission Urgent Repairs

Station Sustainment:

- Station Urgent Repairs
- Station Assessment / Minor Planned Capital
- Minimum Oil Circuit Breaker Replacement

Distribution Sustainment:

- Distribution Lines Condition Assessment
- Distribution Lines Rehabilitation
- Distribution Line Rebuilds
- Forced Upgrades and Line Moves
- Distribution Urgent Repairs
- Distribution Small Planned Capital

Other capital:

- Equipment Capital
- Facilities Capital
- Information Systems Capital, consisting of four programs as described on pages C103 to C-105 of the Application.

These programs begin in January and the in service date is by December of each year.

For individual projects in excess of $2 million, the requested information is provided below. All of the projects were delivered during the Current PBR Plan term. Forecast and actual expenditures shown are for the completed project, although not all expenditures may have occurred during the Current PBR Plan term.

	Forecast ($ millions)	Actual ($ millions)	Anticipated Start/ In-Service Dates	Actual In-Service Date	Explanation of Variances
Ellison to Sexsmith Transmission Tie	$ 7.083	$ 5.083	2011/2013	Dec 2014	Scope of project reduced because of planned highway expansion.
PCB Environmental Compliance	26.200	22.938	2011/2014	Nov. 2014	Reduced scope and contingency drawdown.
Spall Breaker House Reconfiguration	1.443	1.270	2014/2015	Dec. 2015	Construction costs lower than anticipated
RGA/Carmi Voltage Conversion	4.417	3.946	2016/2018	2018	Cost fully recovered through CIAC
Huth 2nd Distribution Transformer	2.821	2.390	2014/2015	2015	Construction costs lower than anticipated

51.3.1 For each project, please identify the following: (i) forecast and actual capital cost; (ii) whether or not the project was delivered; (iii) if the project was delivered, whether it was delivered on-time and within the defined budget; and (iv) for any projects that were not delivered on-time and/or within the defined budget, please provide the time and/or budget variances and a description of the cause(s) of the variances.

Response:

Please refer to the response to BCUC IR 1.51.3.

51.4 Please explain, in detail, whether any planned projects during the Current PBR Plan term were not completed. If not, please explain why.

Response:

The following is a list of the Sustainment projects that FBC identified for execution in the FBC 2014-2018 PBR Application and that were not executed during the Current PBR Plan term.

Name-Description	Reason for Delay	Estimated Cost (million)	Classification	Year Originally Planned	Current Status
DG Bell 138 KV Breaker and Voltage Transformer Addition This project involves the addition of a circuit breaker (CB13) at the DG Bell (DGB) Terminal Station. The project will improve and simplify the protection scheme at the terminal station and increase operational reliability in the Kelowna Area.	This project addresses a low probability event with a high consequence	$ 0.8	4	2017	Planned for 2021

The following is a list of the Growth projects that FBC had identified for execution in the FBC 2014-2018 PBR Application and did not execute during the Current PBR Plan term.

Name-Description	Reason for Delay	Estimated Cost (million)	Classification	Year Originally Planned	Current status
Glenmore Low Voltage Bus Capacity Upgrade Upgrade the 1200A rated LV bus and three bus tie switches (BT-4, BT-6, BT-7) at Glenmore substation from GLE7 to GLE3 feeder tap to a 2000A rating.	Redistribution of load	$ 0.2	5	2017	Deferral beyond 2024

Name-Description	Reason for Delay	Estimated Cost (million)	Classification	Year Originally Planned	Current status
The Summerland Substation transformer: is used to supply the District of Summerland municipal utility with a distribution wholesale supply. The load on the existing Summerland T1 transformer was forecast to exceed 95 percent of the contract Demand Limit in 2015. Under the terms of the wholesale supply agreement, FortisBC would be required to upgrade the supply capacity in order to continue to provide reliable service.	Lower Load growth than previously forecast	$7.0	5	2015	Planned for 2020-2021 pending Municipality of Summerland load forecast and voltage conversion decision
Grand Forks Terminal Feeder Addition Additional feeder to supply Christina Lake from Grand Forks Terminal station	The preferred option requires GFTA project to be complete	$5.0	5	2016-2017	Pending GFT CPCN decision
DG Bell 4 Feeder Addition Currently the DG Bell station has three feeders with a spare breaker available for a future feeder. The original planned solution was to make use of the spare breaker and add a fourth feeder to the station in order to offload the existing load	Waiting for coordination with City of Kelowna project – South Perimeter Road, near DG Bell Substation	$2.0	3	2018	Planned for 2020
Okanagan Long Term Solution Procurement of land to construct a FBC Facility in Kelowna	Challenges with the procurement of land	$12.0	5	2016	To be determined - under development

There are no impacts to customers due to the delay or deferral of the above projects.

51.4.1 Please explain if these projects will be completed during the proposed MRP term and in what year(s).

Response:

Please refer to the response to BCUC IR 1.51.4.

51.4.2 Please provide details of the scope and dollar value of these projects.

Response:

Please refer to the response to BCUC IR 1.54.

51.4.3 Please explain whether any of the projects that were not completed are postponed beyond the proposed MRP term or permanently cancelled. Please explain the impacts to ratepayers, if any, and the dollar value of these projects.

Response:

Please refer to the response to BCUC IR 1.51.4.

On page C-106 of the Application, FortisBC states the following regarding FBC Regular Capital:

> 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.

…

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.

51.5 Please explain in detail the circumstance which would likely result in FBC filing an updated forecast for 2023-2024 capital expenditures in the 2022 annual review.

Response:

FortisBC evaluates its capital plans on an ongoing basis in order to meet forecast load and to ensure the safety, reliability and integrity of the gas and electric systems. Due to the evolving operating environment and other uncertainties inherent in a five-year forecast, FEI and FBC intend to review the capital forecasts for 2023 and 2024 in their respective Annual Reviews for 2023 rates. Some of the factors that may result in the need to file an updated forecast for 2023-2024 capital expenditures include the following:

- **Load growth:**

  Planned growth capital projects are dependent on current expectations of load growth. To the extent that load growth occurs more slowly, more rapidly, or in areas unanticipated at the time of filing, projects will be introduced or re-scheduled to ensure that customer requirements can be met.

- **Condition of facilities:**

  Sustainment capital projects are largely driven by the need to maintain the reliability and integrity of networks and equipment. The Companies conduct condition assessment activities on an ongoing basis; any material developments related to the condition of facilities could likewise result in new projects or in changes to the scope of projects.

- **Third party driven work:**

  Significant infrastructure projects that require FEI or FBC to relocate its assets could result in new projects. Likewise, the cancelation of currently identified infrastructure projects could result in the cancelation or delay of the FEI or FBC required relocations.

- **Scope and Cost Refinement:**

  FEI and FBC continue project development work on the projects identified as Major Projects. While approval of these Major Projects will most likely be sought by way of a

CPCN application, if upon further project development, a Major Project is found not to meet the criteria for a CPCN, it may instead be included in a mid-term update.

- **Other factors:**

  Unknown factors may also affect the inclusion, timing, scope or costing of projects. As an example, the deterioration of the Canada/US exchange rate during the Current PBR Plan term, as discussed in Appendices B8-1 and B8-3 of the Application, contributed to the formula cost pressures for FEI and FBC.

52.0 Reference: FBC CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4.1, pp. C-80 – C-106; Exhibit B-1-2, Evidentiary Update

FBC Regular Capital

On page C-82 of the Application, FBC provides the following table:

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

On page C-84 of the Evidentiary Update to the Application, FBC provides the following table:

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	14,719	20,337	20,338	19,542	19,990	20,353
Telecommunications	2,516	1,818	2,983	6,280	5,915	3,472
Total	$ 30,403	$ 50,743	$ 50,098	$ 43,110	$ 44,657	$ 53,901

On page C-102 of the Application, FBC provides the following table:

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

52.1 Please provide the same information as is provided in Tables C3-22, C3-25 and C3-39 of the Application for: (i) formula years 2014 through 2019; (ii) actual years 2014 through 2018; and (iii) projected 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Growth Capital, Sustainment Capital and Other Capital expenditures for 2014 to 2019P are provided in Tables 1, 2 and 3 below. The 2014 values have been corrected, as identified in the response to BCUC IR 1.51.1.

Table 1: FBC Growth Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Transmission Growth	$ 377	$ 4,224	$ 62	$ 2,939	$ 945	$ 833
Distribution Growth	3,027	1,105	500	1,795	1,153	747
New Connects	15,416	15,938	14,895	17,599	21,906	15,939
Total	$ 18,821	$ 21,267	$ 15,456	$ 22,333	$ 24,003	$ 17,519

Table 2: FBC Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Generation	5,728	2,262	2,105	3,310	3,637	3,476
Transmission Sustainment	12,540	6,416	4,973	4,266	4,749	5,321
Stations Sustainment	10,722	4,093	2,804	5,072	4,434	5,238
Distribution Sustainment	18,089	13,290	14,202	15,320	14,004	14,835
Telecommunications	1,498	1,241	1,562	1,399	1,793	4,357
Total	48,577	27,301	25,645	29,367	28,616	33,227

Table 3: FBC Other Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Equipment	$ 1,744	$ 2,132	$ 2,536	$ 2,636	$ 3,099	$ 2,638
Facilities	1,233	859	1,703	2,267	1,666	2,000
Information Systems	5,116	5,192	5,067	8,980	7,177	10,587
Total	$ 8,093	$ 8,183	$ 9,307	$ 13,882	$ 11,942	$ 15,225

53.0 Reference: FBC CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4.1.1, pp. C-81 – C-84

FBC Growth Capital

FBC provides the following table on page C-82 of the Application:

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

53.1 Please provide a detailed cost breakdown and description of each of the four transmission growth projects identified in Table C3-23 of the Application.

Response:

FBC provides below a cost breakdown and description of each of the four transmission growth projects identified in Table C3-23 of the Application.

Sexsmith 2nd Transformer Addition:

Sexsmith substation currently serves 4,450 residential customers, 1,530 commercial customers, and 2 industrial customers through a single distribution transformer and four distribution feeders. The Sexsmith feeders also provide critical contingency options to back up Ellison, Glenmore, Lee, and Hollywood distribution load in the event of unplanned outages at these stations. The 2018 distribution load forecast indicates that peak load on the existing 32 MVA transformer will exceed nameplate capacity in the summer of 2020.

This project involves the addition of a new 40MVA 138/13kV transformer and two new 13kV distribution feeders. This will allow for continued reliable service to existing customers and will accommodate the significant growth occurring in this part of Kelowna.

The detailed cost estimate breakdown for this project is as follows:

Item	Estimate ($ millions)
Civil & Site	$0.424
Buildings	0.061
Structures and Buswork	0.108
Station Equipment & Apparatus	2.204

Item	Estimate ($ millions)
Communications & SCADA	0.077
Protection and Control, Metering	0.241
Design	0.407
Commissioning	0.051
Project Management	0.286
Distribution Lines	1.187
Overhead	0.421
Total	**$5.467**

Summerland Transformer Replacement:

The estimate for this project is currently at the Class 5 level of scope definition and scope definition is ongoing. A detailed cost breakdown is not available at this time. No further description beyond what was included in the Application is available at this time.

Beaver Park:

The estimate for this project is currently at the Class 5 level of scope definition and scope definition is ongoing. A detailed cost breakdown is not available at this time. No further description beyond what was included in the Application is available at this time.

DG Bell 2nd Transformer Addition:

The estimate for this project is currently at the Class 5 level of scope definition with further scope definition commencing in late 2019. The majority of the project expenditure will be in 2025, so the 2024 forecast is primarily for completion of engineering and purchase of long-lead substation equipment. No further description beyond what was included in the Application is available at this time.

53.1.1 As part of the above response, if contingency amounts are included in any of the projects, please explain why this is appropriate given the proposed 50/50 earnings sharing treatment of variances in regular capital expenditures.

Response:

Contingency amounts are included in the estimates.

FortisBC's utilization of contingency in estimates is consistent with the Association for the Advancement of Cost engineering (AACE International) definition of contingency as:

> An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience…
>
> …Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations (other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and is expected to be expended.

Since the contingency amounts are expected to be expended, it is appropriate to include these contingency items in the total estimate of funds required for project completion.

53.2 Please re-create Table C3-23 to show the transmission growth projects over $1 million which were completed and/or started during the Current PBR Plan term. Please provide the forecast and actual annual capital expenditures for each project.

Response:

The following table provides the transmission growth projects over $1 million with spending in the Current PBR Plan term:

Project Name	Ellison to Sexsmith Transmission Tie		Huth 2nd Distribution Transformer Addition		RGA Carmi Voltage Conversion Construction		Sexsmith 2nd tranformer Addition	
Year	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)
2014	2.628	2.461	0.372	0.267				
2015			2.449	2.407				
2016					0.049	0.062		
2017					4.368	2.939		
2018					0.000	0.945		
2019							0.807	0.038
2020							4.633	

54.0 Reference: FBC SUSTAINMENT CAPITAL

Exhibit B-1, Section C3.4.1.2, pp. C-84 – C-102; FBC PBR Application proceeding, Exhibit B-1, pp. 189–192

FBC Generation Sustainment Capital

FBC states on pages C-84 and C-85 of the Application that it groups its generation capital into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

54.1 Please re-create the following tables to show the actual generation sustainment capital expenditures for actual years' 2014 through 2018 and projected 2019 and the formula capital expenditures for years' 2014 through 2019: Tables C3-26, C3-27, C3-28, C3-29 and C3-30.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Total Generation capital expenditures for 2014 to 2019P are provided in the table below.

Table 1: FBC Generation Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Hydraulic Dam Structures	705	681	348	1,108	1,689	1,190
Generating Equipment	2,091	134	90	309	377	1,163
Generation Auxiliary Equipment	2,171	573	1,139	997	875	758
Buildings and Structures	760	874	528	897	697	366
Total	5,728	2,262	2,105	3,310	3,637	3,476

A separate table showing details for each of the above four categories are provided below.

Table 2: FBC Hydraulic Dam Structures Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Concrete Structures Rehabilitation	$ 705	$ 425	$ 293	$ 505	$ 493	$ 389
LBO Spillway Gates Refurbishment	-	100	-	117	1	159
Other Gates Upgrades	-	131	28	233	608	-
Dam Safety Instrumentation	-	-	-	253	588	445
Guarding of Rotating Parts	-	-	-	-	-	17
Other Hydraulic Dam Structures Projects	-	25	27	-	-	182
Total	$ 705	$ 681	$ 348	$ 1,108	$ 1,689	$ 1,190

Table 3: FBC Generating Equipment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
UBO Unit 6 Turbine Runner Replacement	$ -	$ -	$ -	$ -	$ -	$ -
Generator Excitation and Control Systems	-	-	-	-	-	-
Generator Thrust Bearing Cooling System	-	-	-	1	103	299
Other Generating Equipment Projects	2,091	134	90	308	274	864
Total	$ 2,091	$ 134	$ 90	$ 309	$ 377	$ 1,163

The 2014 capital expenditures are for various upgrades to non-generating components of the Upper Bonnington Old Units.

Table 4: FBC Generation Auxiliary Equipment Capital Expenditures Forecast 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Dewatering and Drainage Systems	$ -	$ 56	$ 215	$ 52	$ 72	$ 55
Station Service Upgrade	4	-	-	8	61	122
Other Auxiliary Equipment Projects	2,167	517	924	937	741	581
Total	$ 2,171	$ 573	$ 1,139	$ 997	$ 875	$ 758

The 2014 capital expenditures are for numerous minor sustainment projects at FBC's four generating plants.

Table 5: FBC Generation Buildings and Structures Capital Expenditures Forecast 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
COR Annex Building Replacement	$ -	$ 111	$ 24	$ 176	$ 52	$ -
Floor Covers Replacement	-	-	-	25	468	177
Roof Replacement	-	-	-	-	-	-
Other Buildings and Structures Projects	760	763	504	695	177	189
Total	$ 760	$ 874	$ 528	$ 897	$ 697	$ 366

On pages 189 and 192 of the FBC PBR Application, FBC described eight generation sustainment capital projects to be undertaken during the Current PBR Plan term, including work on Upper Bonnington, Lower Bonnington and Corra Linn.

54.2 Please further explain what is driving the increased capital expenditures on generation capital programs during the proposed MRP term. As part of this response, please compare and contrast the eight generation projects planned during the Current PBR Plan term to the projects planned to be undertaken during the proposed MRP.

Response:

The main drivers for the increased capital expenditures on generation capital programs during the proposed MRP term are described below.

Driver 1 - Compliance with Dam Safety and Occupational Health and Safety (OHS) regulations, which includes the following projects:

- **Other Gates Upgrade Project**

  This project includes the refurbishment and upgrade of the intake, spillway, tailrace gates, stoplogs and associated operating devices installed at Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan, to rectify age-related condition issues, meet current regulations under OHS 9.18(3) (b) rule related to the requirement for single device isolation (SDI) certification for any area such as a water passageway that must be isolated by a single device. The Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $1.8 million over 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. In 2013 FBC received a WorkSafe BC order to address the missing of guards on rotating equipment at one of its third party plants. FBC has complied with the order and in 2016 initiated a program to address this situation at FBC-owned plants. The Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $1.6 million over the period 2020-2024.

- **The Floor Covers Replacement Project**

  FBC's plants were constructed before current OHS requirements were developed and as such, most of the covers installed do not have the strength required and are not or cannot be guarded as required. The covers are installed throughout the plant, including over openings in the floors of the powerhouse which are needed to access and remove heavy equipment from one floor to the other, and over openings on the tailrace deck and

on the forebay deck which are required to store or operate gates and stop logs. In 2013 FBC received a WorkSafe BC order to address the floor covers situation at one of its third party plants. FBC has complied with the order and in 2017 FBC replaced the floor covers installed on the tailrace deck at South Slocan. The Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $1.0 million over the period 2020-2024.

- **Dam Safety Instrumentation Project**

The scope of this project 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 started under the Current PBR Plan in 2018 with the first plant, Lower Bonnington, to be completed in 2019. The spending under the Current PBR Plan was $0.32 million. The project will continue under the proposed MRP with the installation of dam monitoring systems at Upper Bonnington and South Slocan and with upgrading the Corra Linn dam monitoring system. The cost for this project is approximately $2.3 million for the period 2020-2024.

Driver 2 - Upgrades to equipment due to condition and obsolescence which includes the following projects:

- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project**

This project involves the refurbishment of the two spillway gates installed at LBO to rectify age-related condition issues, meet current regulations, and minimize the risks to public and employee safety. The Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $2.9 million with an estimated in service date of 2021.

- **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 Current PBR Plan did not include a similar project. 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

Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $1.2 million over the period 2021-2024.

- **Dewatering and Drainage Systems Rehabilitation Project**

  This project is a continuation of the program started under the Current PBR Plan 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. Under the Current PBR Plan FBC incurred expenditures of approximately $0.5 million.

Driver 3 - Deterioration of aged concrete structures and buildings that pose a risk to operations and personnel safety includes the following projects:

- **Corra Linn Annex Building Replacement Project**

  This project includes the replacement of the 87-year old Corra Linn Annex building, which has structural damage due to foundation settlement. The Annex Building is part of the powerhouse and is composed of: a fire pump room, a battery room, a washroom and an office and houses critical infrastructure for emergency operations. The Annex Building's structure has visible signs of concrete damage and cracking at critical structural locations. The primary cause of this deterioration is foundation settlement on the north side of the structure, which is causing the Annex Building to pull away from the powerhouse. The Current PBR Plan did not include a similar project. The estimated cost of this project is $1.8 million with a planned in-service date of 2024.

- **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 estimated cost of this project is approximately $4.6 million over the period 2020-2024, as compared to $2.8 million over the Current PBR plan. The increase is due mainly to FBC proactively addressing, under the proposed MRP, a higher number of locations that are showing deterioration.

The eight generation projects planned during the Current PBR Plan term are:

1. Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels

This program involves the installation of fire alarm annunciation panels and was completed in the Current PBR Plan term.

2. Corra Linn Dam Spillway Gate Replacement

A CPCN for this project was approved by Order C-1-17 and was not included in regular capital expenditures either during the Current PBR Plan or the proposed MRP. The concrete work includes remediation of selected concrete piers noses to accommodate the installation of the semi gantry rail installed as part of the project and remediation of the spillway gates embedded parts (bottom of the spillway gate sills and the roller paths).

3. All Plants Safety and Security

This program involves upgrades to the plant security fences and signage to restrict public access to dangerous or controlled areas such as the tailrace area. The program was completed in the Current PBR Plan term with the exception of the installation of a perimeter fence at Corra Linn on the canal side due to interference with the Corra Linn Spillway Gate Replacement project which started in 2018. The fence is planned for installation after the completion of the Corra Linn Spillway Concrete and Spill Gate Rehabilitation project and is included in the Other Buildings and Structures Projects category in the proposed MRP.

4. All Plants Fire Safety

This program involves upgrading the fire egress from the powerhouse by adding fire exits crash doors, installing fire stop materials and upgrading the generator deluge systems and was completed in the Current PBR Plan term.

5. All Plants Concrete and Structural Rehabilitation

This program involves the correction of deficiencies and degradation of concrete and structural steel installations. The FBC generation plants range in vintage from 87 to 112 years old. Concrete deterioration is a progressive reduction in concrete properties which can result in a material loss and thus reduced cross section, an internal change in concrete properties (strength, modulus of elasticity, Poisson's ratio, density) which reduces overall structural load carrying capacity.

FBC's approach in executing the concrete deterioration project is to assess the concrete structures every 7 to 10 years and plan the repairs based on a priority sequence with the highest priority areas being scheduled within 1 to 2 years after being identified. The concrete rehabilitation program was started in 2012 and will continue throughout the proposed MRP.

6. Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows

This program involves the refurbishment and replacement of broken windows. The program was completed in the Current PBR Plan term with the exception of the installation of powerhouse windows at Corra Linn due to interference with the Corra Linn Spillway Gate Replacement project. The Corra Linn powerhouse windows replacement project is planned after the completion of the Corra Linn Spillway Gate Replacement project and is included in the Other Buildings and Structure Projects category as part of the proposed MRP.

7. Dam Safety Instrumentation

This program involves the upgrade of existing or installation of additional dam safety instrumentation and was started in 2018. The first plant to be completed will be LBO in 2019. The program will continue in the proposed MRP with installation of dam monitoring systems at UBO and SLC and upgrading of the COR dam monitoring system with the objective that all plants will be compliant with the BC Dam Safety Regulation by 2022.

8. All Plants Minor Sustainment Capital

This program involves small individual projects which can range from replacement of fans and motors to upgrade of crane components and replacement of embedded piping. Under the proposed MRP this program includes projects which are included in the following categories: Other Generating Equipment Projects, Other Auxiliary Equipment Projects and Other Buildings and Structures. The proposed MRP includes a separate project to address embedded piping, dewatering and drainage systems rehabilitation project, which is described above.

On page C-85 of the Application, FBC states that the Concrete Structures Rehabilitation Project 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."

54.3 Please compare the total actual/projected capital expenditures on the Concrete Structures Rehabilitation Project during the Current PBR Plan term to the forecast capital expenditures during the proposed MRP term and explain any spending variances.

Response:

The total actual/projected capital expenditures during the Current PBR Plan are presented in the response to BCUC IR 1.54.1 and the forecast expenditures over the MRP term are shown in

Table C3-27 at page C-85 of the Application. The difference between the expenditures in the Current PBR Plan term ($2.809 million) and the proposed MRP term ($4.632 million) is $1.823 million. The projected capital expenditures during the proposed MRP are discussed below.

The $1.823 million variance between the 2014-2019 actual/projected expenditures and the forecast capital expenditures during the proposed MRP term is related mainly to the increased amount of work FBC's is planning to undertake during the proposed MRP term. The projected capital expenditures during the proposed MRP are discussed below.

FBC assesses the concrete structures every 7 to 10 years and plans the repairs of the deteriorated concrete structures based on a priority sequence with the highest priority areas being scheduled within 1 to 2 years after being identified.

The FBC generation plants range in vintage from 87 to 112 years old. Concrete deterioration is a progressive reduction in concrete properties which can result in a material loss and thus reduced cross section, an internal change in concrete properties (strength, modulus of elasticity, Poisson's ratio, density) which reduces overall structural load carrying capacity.

A third party concrete structure inspection was undertaken in 2009, which identified and prioritized the scope of work at all four FBC's owned dams, and which formed the basis for FBC's concrete rehabilitation plan for the Current PBR Plan term. FBC has addressed some of the locations identified with a high and medium priority in the 2009 report.

As a follow-up to the 2009 inspection, another third party concrete inspection was undertaken in 2018 to reassess the degradation of the concrete structures at LBO and SLC and determine the priority work for the 2019-2024 period.

Finally, in 2018, a repair plan was completed for the Corra Linn air chamber roof structure based on a 2017 detailed condition assessment. The condition assessment of Corra Linn Air Chamber Roof structure was undertaken to determine its load rating for the upcoming Corra Linn Spillway Gate Replacement project work, which required that various loads be placed on the roof during construction. The condition assessment determined that due to the extent of concrete deterioration the roof structure could only support light loads like light foot traffic and that in order to prevent further deterioration extensive repairs need to be undertaken to bring the roof in compliance with the loading requirements of BC Building Code. The cost of the repair is approximately $1.128 million and is planned for 2023.

Based on the locations identified at South Slocan and Lower Bonnington in the 2018 concrete inspection report, the 2018 Corra Linn air chamber roof repair plan and the locations at Upper Bonnington identified under the 2009 report which were not addressed, FBC developed the concrete rehabilitation plan under the proposed MRP which is presented in the table below.

Concrete Structures Rehabilitation Project Forecast 2020-2024 ($000s)

Location	2020	2021	2022	2023	2024
LBO South Wall	$ 685	$ -	$ -	$ -	$ -
LBO Tailrace, South Deck and River Side Piers	-	821	-	-	-
LBO Stairway Area and LBO Air Wash Chamber	-	-	979	-	-
COR Air Wash Chamber Roof	-	-	-	1,128	-
SLC High and UBO Medium Priority Items	-	-	-	-	1,019
Total	$ 685	$ 821	$ 979	$ 1,128	$ 1,019

55.0 Reference: FBC SUSTAINMENT CAPITAL

Exhibit B-1, Section C3.4.1.2, pp. C-84 – C-102

FBC Transmission Sustainment Capital

FBC states on page C-89 of the Application that it has broken down transmission sustainment capital into four programs: (i) Transmission Line Condition Assessment; (ii) Transmission Line Rehabilitation; (iii) Transmission Urgent Repairs; and (iv) Transmission Rights of Way.

55.1 Please re-create the following tables to show the actual transmission sustainment capital expenditures for actual years' 2014 through 2018 and projected 2019 and the formula capital expenditures for years' 2014 through 2019: Tables C3-31, C3-32 and C3-33.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Transmission Sustainment capital expenditures for 2014 to 2019P are provided in Tables 1 through 3 below.

Table 1: FBC Transmission Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Transmission Line Condition Assessment	$ 526	$ 389	$ 487	$ 468	$ 467	$ 725
Transmission Line Rehabilitation	3,473	4,907	3,743	2,865	3,052	3,641
Tranmission Urgent Repairs	318	522	299	486	786	445
Transmission Rights of Way	465	397	444	446	443	510
Other Transmission Sustainment	7,758	201	-	-	-	-
Total	$ 12,540	$ 6,416	$ 4,973	$ 4,266	$ 4,749	$ 5,321

Other Transmission Sustainment Projects in 2014 included expenditures for the Ellison to Sexsmith Transmission Tie project ($2.620 million) and projects deferred as a result of the 2013 labour dispute which were not captured in the sustainment program costs.

Table 2: FBC Transmission Line Rehabilitation Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
30 Line Rehabilitation	$ -	$ -	$ -	$ -	$ -	$ 1,500
Other Transmission Line Rehabilitation	3,473	4,907	3,743	2,865	3,052	2,141
Total	$ 3,473	$ 4,907	$ 3,743	$ 2,865	$ 3,052	$ 3,641

Table 3: FBC Transmission Line Rights of Way Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
30, 32, 19 Lines Rights of Way	$ -	$ -	$ -	$ -	$ 60	$ 56
Transmission Rights of Way	465	397	444	446	383	454
Total	$ 465	$ 397	$ 444	$ 446	$ 443	$ 510

56.0 Reference: FBC SUSTAINMENT CAPITAL

Exhibit B-1, Section C3.4.1.2, pp. C-84 – C-102

FBC Stations Sustainment Capital

FBC provides details of planned capital spending on stations sustainment capital on pages C-91 to C-95 of the Application.

56.1 Please re-create the following tables to show the actual stations sustainment capital expenditures for actual years' 2014 through 2018 and projected 2019 and the formula capital expenditures for years' 2014 through 2019: Tables C3-34, C3-35 and C3-36.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Total Stations Sustainment capital expenditures for 2014 to 2019P are provided in Table 1 below, with further detail provided in Tables 2 and 3.

Table 1: FBC Stations Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Station Urgent Repairs	$ 676	$ 894	$ 553	$ 436	$ 897	$ 568
Station Assessment/Minor Planned	1,166	1,158	1,352	1,262	1,079	1,286
Transformer Replacements	-	-	-	1,261	-	-
Salmo Station Upgrade	-	-	-	-	-	-
Fruitvale Station Upgrade	-	-	-	-	-	-
Station Equipment	8,880	2,041	899	2,114	2,457	3,384
Total	$ 10,722	$ 4,093	$ 2,804	$ 5,072	$ 4,434	$ 5,238

Table 2: FBC Station (T&D) Transformer Replacement Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
FA Lee Transformer 4 Load Tap Changer	$ -	$ -	$ -	$ 1,261	$ -	$ -

Table 3: FBC Station Equipment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Generating Stations Assets	$ -	$ -	$ -	$ -	$ 402	$ 560
Ground Grid Upgrades	610	-	690	-	336	-
Minimum Oil Circuit Breaker Replacement	-	-	-	1,103	798	1,249
Bulk Oil Breaker Replacement	-	188	-	747	440	201
Station Oil Containment	-	77	209	263	447	-
Other Equipment	8,270	1,776	-	-	34	1,373
Total	$ 8,880	$ 2,041	$ 899	$ 2,114	$ 2,457	$ 3,384

Other Equipment includes expenditures for PCB Environmental Mitigation ($8.135 million in 2014 and $0.609 million in 2015).

56.2 Please compare and contrast the number and types of stations sustainment capital projects planned during the Current PBR Plan term to the projects planned to be undertaken during the proposed MRP.

Response:

In the Current PBR Plan term, FBC executed, in addition to its ongoing Sustainment Capital programs, the following Station Sustainment Capital projects described in Section 5.4.3 of the FBC 2014-2018 PBR Application:

- Environmental Compliance (PCB Mitigation) for stations;
- Osoyoos 63 kV Breaker Addition; and
- DG Bell 138 kV Breaker (CB13) and Voltage Transformer Addition.

Of the above projects, the Environmental Compliance and Osoyoos 63 kV Breaker Addition projects were completed. FBC will execute the DG Bell 138 kV Breaker (CB13) and Voltage Transformer Addition project during the MRP term.

In the MRP term, FBC is proposing the following five Station Sustainment projects to address upgrades to equipment condition, obsolescence and to maintain adequate levels of reliability:

- AS Mawdsley Transformer Replacement;
- Trout Creek Transformer Replacement;
- Kaleden Transformer Replacement;

- Salmo Station Upgrade; and
- Fruitvale station Upgrade.

These projects are described on pages C-92 and C-93 of the Application.

57.0 Reference: FBC SUSTAINMENT CAPITAL

Exhibit B-1, Section C3.4.1.2.4, pp. C-95, C-97 –C-98; Exhibit B-1-1, Appendix A3-2, pp. 1–3; FBC PBR Application proceeding, Exhibit B-1, p. 202

FBC Distribution Sustainment Capital

On page C-95 of the Application, FortisBC provides Table C3-37 which shows the 2017-2019 average and the 2020-2024 forecast distribution sustainment expenditures broken down into various categories.

57.1 Please re-create Table C3-37 to show the actual distribution sustainment capital expenditures for actual years' 2014 through 2018 and projected 2019 and the formula capital expenditures for years' 2014 through 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Distribution Sustainment capital expenditures for 2014 to 2019P are provided in the table below.

Table 1: FBC Distribution Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Distribution Line Condition Assessment	$ 1,142	$ 1,099	$ 1,410	$ 1,480	$ 1,135	$ 2,019
Distribution Line Rehabilitation	2,906	2,145	3,238	3,326	3,068	3,044
Distribution Line Rebuilds	1,808	1,740	1,447	2,727	1,361	1,968
Distribution Urgent Repairs	2,563	4,414	1,739	2,998	3,724	2,616
Distribution Small Planned Capital	536	683	751	915	896	968
Forced Upgrades and Line Moves	2,439	1,625	4,362	2,323	2,348	2,120
PCB Environmental Compliance	-	-	639	731	596	867
Porcelain Cutouts Replacement	-	-	-	-	-	-
Meter Exchanges	17	(24)	22	11	24	129
LED Street Light Retrofits	-	-	-	-	398	711
Other Distribution Sustainment Projects	6,680	1,608	595	810	454	394
Total	$ 18,089	$ 13,290	$ 14,202	$ 15,320	$ 14,004	$ 14,835

Other Distribution Sustainment Projects in 2014 included $5.657 million of expenditures deferred as a result of the 2013 labour dispute which were recorded as an aggregate amount rather than in the individual sustainment program costs.

On page C-96 of the Application, FBC describes its Small Planned Capital work as follows:

> 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.

On pages 1–3 of Appendix A3-2, FortisBC provides FBC's O&M expenditures from 2013-2017.

57.2 Please explain where expenses for Storm Restoration are provided.

Response:

Storm Restoration expenses are included in Urgent Repairs (Station, Transmission and Distribution) under Sustainment Capital.

57.2.1 If a portion of the storm restoration cost is O&M, and not capital, please explain.

Response:

Storm restoration costs are capitalized under the Urgent Repair Sustainment Capital Project.

57.2.2 Please discuss if storm restoration costs include restoration costs due to forest fires.

Response:

Storm restoration costs do not include costs due to forest fires. Forest fire restoration costs are also capitalized under Urgent Repairs Sustainment Capital.

57.2.2.1 If yes, please provide a breakdown of the costs in the questions below between storm restoration and forest fire restoration.

Response:

Pleaser refer to the response to BCUC IR 1.57.2.2.

57.2.2.2 If no, please explain where maintenance costs associated with forest fires are included and provide the actual amounts for forest fire restoration for the time periods detailed in the questions below.

Response:

Forest fire restoration costs are provided from Urgent Repairs Sustainment Capital. Actual costs incurred due to forest fires are as follows:

- 2013 $0.013 million
- 2014 $0.000 million
- 2015 $2.400 million ($2.152 million was approved as an exogenous factor)
- 2016 $0.037 million
- 2017 $0.483 million

57.2.3 Please detail FBC's Storm Restoration expenses for actual years' 2013 through 2018 and projected 2019, noting any identified trends.

Response:

FortisBC storm restoration costs for years 2013-2018 are below:

- 2013 $1.03 million
- 2014 $1.17 million
- 2015 $1.39 million
- 2016 $0.35 million
- 2017 $1.05 million
- 2018 $1.33 million

The Projected cost for storm restoration in 2019 is $0.94 million based on a three-year rolling average. Past history indicates seasonal storms occur in June, August and November. The severity of the weather events, which drives the cost, varies from year to year.

57.2.4 Please provide dates and actual costs of the three most costly storms for FBC that have occurred in the last ten years.

Response:

The dates and actual costs of the three most costly storms for FBC that have occurred in the last ten years are provided below:

- June 29-30, 2015 $0.858 million
- November 22-25, 2014 $0.846 million
- July 17-20, 2012 $0.684 million

57.3 Please explain and quantify the damage to fixed assets due to wildfires for the past two years.

Response:

In 2018, FortisBC did not experience any damage due to wildfires. In 2017 the following assets were damaged due to wildfires:

- April 2017 Cawston Distribution $0.025 million
- June 2017 Cawston Distribution $0.019 million

- July 2017 Cawston — Transmission 43L — $0.025 million
- July 2017 Princeton — Distribution — $0.328 million
- July 2017 Kaleden — Distribution — $0.038 million
- July 2017 Christian Valley — Distribution — $0.001 million
- August 2017 Joe Rich — Distribution — $0.023 million
- August 2017Joe Rich — Transmission 57L — $0.024 million

57.3.1 Please break down the equipment types that have sustained damage due to wildfires in the past two years (i.e. poles, lines, substations, etc.)

Response:

FortisBC assets that have been damaged by wildfires in the last two years include distribution poles, distribution insulators, wires, distribution transformers and related hardware. Also damaged in the last two years were transmission poles, transmission insulators and wire.

57.4 Please provide FBC's Storm Restoration budget for each year of the proposed MRP term and explain how FBC determined that this budget is appropriate.

Response:

FBC's storm restoration budget is embedded in the overall Urgent Repair Sustaining Capital budget. The overall Urgent Repair Sustaining Capital budget is based on a three year rolling average of actual expenditures.

57.5 Please discuss the steps FBC has taken and/or plans to undertake to minimize future damage from storms and wildfires during the proposed MRP term. As part of the discussion, please also discuss FBC's strategy with respect to vegetation maintenance.

Response:

FBC has implemented multiple layers of defense to ensure that future damage from storms and wildfires are minimized. The first layer of this involves the execution of FBC's Asset Management program to ensure that the system remains in a resilient state and able to withstand these types of environmental impacts.

The FBC Transmission and Distribution system has a Condition Assessment performed on an eight year cycle. 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 rehabilitation budget. Ensuring that the FBC Transmission and Distribution facilities are maintained in good order is a key component for preventing future storm and wildfire damage.

Supplementing the Condition Assessment, an Annual Line Patrol (ALP) is completed on the full Transmission and Distribution System yearly. This will identify any issues that may arise outside of the eight year Condition Assessment cycle. Any deficiencies that are identified during the ALP that would prevent the facility from safely performing its function to its next planned Condition Assessment cycle will be repaired off-cycle.

FBC's strategy with respect to vegetation maintenance is to have a systematic, methodical approach to vegetation management on all transmission and distribution facilities throughout the FBC service area. A well developed vegetation maintenance program inherently reduces the risk of wildfires by reducing grow-ins and the possibility of obvious hazard trees falling into the line.

Tall growing vegetation near transmission and distribution power lines is a cause of electrical outages and can create public safety hazards. FBC controls vegetation under, above and near its transmission and distribution facilities through a vegetation management program in order to maintain the safe, reliable distribution of electricity to its customers.

FBC utilizes the principles of Integrated Pest Management (IPM) to manage unwanted vegetation on its transmission and distribution systems. Regular inspections and patrols are conducted to determine the physical location and condition of vegetation and hazard trees. Vegetation that could grow, or is expected to fall, into FBC lines will be removed. If removal is not possible, required clearances will be achieved through appropriate vegetation management methods. Vegetation management practices include manual and mechanical techniques as well as the selective use of herbicides.

Using this approach, the Rights of Way (ROWs) on which FBC facilities are located are maintained in a manner that minimizes encroachments, leading to a more robust and resilient system with respect to storm and wildfire damage.

As a method of continuously improving, FBC is enhancing its ROW for 30, 32 and 19 Lines. The scope of this multi-year project involves acquiring additional ROW 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 ROW 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.

Additionally, on transmission facilities 200 kV or higher, FBC meets or exceeds the requirements of Mandatory Reliability Standard FAC-003-4 'Transmission Vegetation Management'.

As a further defense against wildfire damage, FBC and the British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development, have a Wildfire Response Agreement in place. In the event that a wildfire has the potential to threaten FBC assets the Province will use its best efforts to provide its services to protect them.

57.6 Please clarify whether vegetation management is included in MRS-related Base O&M.

Response:

There is a small amount allotted for vegetation management in MRS-related Base O&M. This is to cover the cost of additional patrol, auditing and vegetation management work that is over and above what is typically required for non-MRS transmission line work.

57.6.1 If yes, please provide the annual actual/projected and formula O&M expenditures for vegetation management that has been captured under MRS activities during the Current PBR Plan term as well as the annual amount proposed to be included in the formula O&M for the proposed MRP term.

Response:

Under the Current PBR Plan, FBC's formula O&M expense is determined at the aggregate level. FBC does not have disaggregated formula amounts by department or activity. FortisBC is proposing an Index-Based approach based on total O&M per customer to determine overall O&M funding for the MRP period. As a result, FortisBC has not prepared a forecast of O&M over the term of the proposed MRPs.

As explained in the response to BCUC IR 1.39.4, FBC's approach to calculate the 2019 Base O&M in Table C2-14 is based on taking FBC's total 2018 O&M actual expenditures and applying an inflation factor, incorporating required adjustments and then adding the incremental funding required - New Funding for MRP term. For this reason there is no 2019 Base O&M value for the specific activity requested.

The table below provides (in $millions) the 2014 to 2018 Actual and 2019 Projected values for MRS-related vegetation management activities.

2014	2015	2016	2017	2018	2019P
$0.052	$0.038	$0.049	$0.048	$0.053	$0.048

57.6.2 For all other vegetation management expenditures outside of MRS activities, please provide the annual actual/projected and formula amounts during the Current PBR Plan term and the annual amount proposed to be included in the formula O&M for the proposed MRP term.

Response:

Under the Current PBR Plan, FBC's formula O&M expense is determined at the aggregate level. FBC does not have disaggregated formula amounts by department or activity. FortisBC is proposing an Index-Based formula approach based on total O&M per customer to determine overall O&M funding for the MRP period. As a result, FortisBC has not prepared a forecast of O&M over the term of the proposed MRPs.

As explained in the response to BCUC IR 1.39.4, FBC's approach to calculate the 2019 Base O&M in Table C2-14 is based on taking FBC's total 2018 O&M actual expenditures and applying an inflation factor, incorporating required adjustments and then adding the incremental funding required - New Funding for MRP term. For this reason there is no 2019 Base O&M value for the specific activity requested.

The table below provides (in $ millions) the 2014 to 2018 Actual and 2019 Projected values for non-MRS-related vegetation management activities.

2014	2015	2016	2017	2018	2019P
$ 5.964	$ 5.656	$ 5.696	$ 5.820	$ 5.689	$ 5.300

On page C-97 of the Application, FBC states that the Forced Upgrades and Line Moves program is required to complete distribution upgrades driven by third party requests.

57.7 Please explain in detail how FBC derives its forecasts for Forced Upgrades and Line Moves.

Response:

The forecast for Forced Upgrades and Line Moves is based on a rolling three-year average of actual expenditures, adjusted for inflation. Any projects known to be required are considered when preparing the forecast.

57.7.1 As part of this response, please explain if any of the forecast capital expenditures during the proposed MRP term are based on known requests.

Response:

No projects have been identified for the MRP term at this time.

On page C-97 of the Application, FBC describes the capital expenditures related to "Environmental Compliance – Distribution Equipment (PCB)" and states that the "proposed expenditures for this project are for the remediation plan which begins in 2019.

On page 202 of the FBC PBR Application, FBC described the "Environmental Compliance – Distribution Equipment (PCB)" capital expenditures and stated: "Proposed expenditures for this project include completion of testing of distribution equipment in 2014 and 2015 followed by initiation of a remediation plan commencing in 2016."

57.8 Please explain why the remediation plan is stated to commence in 2019 in this Application given the statements in the PBR Application (as provided in the above preamble).

Response:

FBC's activity related to Environmental Compliance – Distribution Equipment (PCB) is a multi-year program which began in 2014/15 with estimating, data collection, project planning, and environmental management planning. In 2016/2017, FBC investigated approximately 6,800 transformers and collected 1,800 oil samples in order to verify PCB levels in FBC distribution transformers and complete the planning process. In 2017, FBC purchased 100 transformers in preparation for the 2018 remediation plan and began replacing transformers. FBC targeted the first 100 transformers with the highest level of PCB contamination, some of which were located in highly sensitive environmental areas (i.e., waterways, marsh lands, and agricultural areas).

In 2019, FBC procured an additional 160 transformers and completed the associated engineering and design for these locations. Approximately 125 transformers will be replaced in 2019 and are coordinated with other programs to reduce the impact of customer outages.

2019 represents the commencement of substantial remediation work in the field. Spending levels are therefore expected to increase in relation to initial years and will continue through the MRP term. FBC's plan includes the replacement of approximately 1,450 distribution transformers and related distribution equipment over the MRP term

57.9 Please explain in detail the work which was performed during the Current PBR Plan term and compare this work to what is planned during the proposed MRP term.

Response:

Please refer to the response to BCUC IR 1.57.8.

On pages C-97 and C-98 of the Application, FBC describes the Porcelain Cutouts Replacement program and states: "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."

57.10 Please explain whether FBC considered filing a CPCN application for this project and why such an approach would not be more appropriate given the cost and scope.

Response:

FBC is not considering filing a CPCN application for this project because the estimated cost does not meet the CPCN threshold of $20 million. The program consists of a high volume of low-cost activity, which will be performed entirely on existing facilities and does not raise public interest issues (other than improving the safety and reliability of the equipment) that would warrant the more extensive regulatory proceeding associated with a CPCN application. The inclusion of the program as part of the 2020-2024 forecast in the Application provides a sufficient opportunity for review of the program and is more efficient from a regulatory perspective than undertaking a CPCN application.

On page C-98 of the Application, FortisBC describes FBC Meter Exchanges as follows:

> This category includes the meter replacements and exchanges for metering equipment that fails during the metering compliance or meter re-test program. Metering infrastructures 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.

57.11 Please explain the statement "FBC has only had expenditures … to cover meter damage and meter failures".

Response:

The statement is intended to indicate that, as expected, FBC has not had to exchange AMI meters for Measurement Canada compliance sampling purposes. Meter exchange expenditures have nevertheless been required, as expected, to replace damaged and failed AMI meters.

57.11.1 Please provide further details on the meter damage.

Response:

Meters may be damaged in a variety of ways, including being struck by an object or being damaged in a building fire. If the damage results in the meter being unable to measure electricity use or to properly transmit its data, then the meter will be exchanged.

57.11.2 Please provide further details on the meter failures. Please explain whether these failures are related to the advanced metering infrastructure (AMI) meters.

Response:

Meter failures would be any issue resulting in the meter being unable to transmit data or the inability to measure. Meter failures have always occurred, but AMI meters have potential new failure modes due to the fact that they have new capabilities, including two-way radio communication and remote shut-off capabilities. Nevertheless, the overall failure rate of the meters has been approximately 0.5 percent per year, which is within the project estimate.

57.11.2.1 Please provide any data FBC has on the expected lifespan of the AMI meters.

Response:

To date the expectation of the lifespan of AMI meters has not deviated from business case projections of 20 years.

57.11.2.2 Please explain whether these failing meters are under warranty from the manufacturer.

Response:

FortisBC has been returning meters to the manufacturer under warranty. To date approximately 600 meters have been returned and replaced under warranty.

57.12 Please confirm, or explain otherwise, that the AMI project is complete.

Response:

Confirmed, the AMI project is complete.

57.12.1 If confirmed, please explain why the Meter Exchanges spending is not $0.

Response:

The AMI CPCN anticipated the need for meter exchanges for the reasons outlined in the response to BCUC IR 1.57.11, and these are occurring.

57.13 Please further explain in detail why FBC's capital expenditures related to meter exchanges are forecast to increase during the proposed MRP term compared to the Current PBR Plan term.

Response:

Measurement Canada regulations require that FBC begin sampling any type of meter, including AMI meters, prior to their seal expiry to ensure ongoing accuracy. The need to resume the meter exchange program has been expected and the costs were included in the project financial analysis in the CPCN application.

58.0 Reference: FBC SUSTAINMENT CAPITAL

Exhibit B-1, Section C3.4.1.2, pp. C-84 – C-102, C-113

FBC Telecommunications Sustainment Capital

58.1 Please re-create Table C3-38 on page C-99 of the Application to show the telecommunications sustainment capital expenditures for actual years' 2014 through 2018 and projected 2019 and the formula capital expenditures for years' 2014 through 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Telecommunications Sustainment capital expenditures for 2014 to 2019P are provided in the table below.

Table 1: FBC Telecommunications Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Communications Upgrades	$ 578	$ 376	$ 456	$ 132	$ 239	$ 369
Station Smart Device Upgrades	206	226	346	486	429	370
SCADA Systems Sustainment	585	-	-	528	571	609
Systems Upgrades and Replacements	-	477	594	30	412	2,815
Other Telecommunications	128	162	165	223	141	193
Total	$ 1,498	$ 1,241	$ 1,562	$ 1,399	$ 1,793	$ 4,357

The 2019 Telecommunications expenditures include the acquisition of existing fibre optic cable on FBC's transmission lines.

On page C-100 of the Application, FBC states the following:

> 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.

On page C-113 of the Application, FBC states the following:

> 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.

58.2 Please confirm, or explain otherwise, if FBC has identified a need, independent of any future MRS requirements, to upgrade existing SCADA systems.

Response:

Yes, FBC has identified a need to upgrade/update existing SCADA systems independent of any future MRS requirements. Operational Technologies such as SCADA systems have been changing for many years. New technologies have become available that will improve FBC's operational efficiency and situational awareness, additional field assets have become economic to manage remotely, and the risks related to cybersecurity have emerged.

For these reasons, the SCADA system will continue to require investment to allow FortisBC to efficiently deliver service to its customers. Though mandatory MRS requirements have introduced additional constraints to the design and operation of the SCADA system, they are not the only driver for system upgrades.

58.3 Please discuss whether MRS-related SCADA upgrades under the SCADA sustainment program and their associated O&M costs would be considered MRS items outside of regular capital and indexed O&M.

Response:

Only incremental MRS-related costs are proposed to be treated outside of Regular capital and index-based O&M. Please refer to the responses to BCUC IRs 1.36.6 and 1.36.8 for a discussion of MRS-related cost treatment during the term of the proposed MRPs.

59.0 Reference: FBC OTHER CAPITAL

Exhibit B-1, Section C3.4.1.3, pp. C-102 – C-105

FBC Other Capital

On page C-102 of the Application, FBC states that equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment.

59.1 Please separately provide the actual 2014 through 2018, projected 2019, formula 2014 through 2019, and forecast 2020 through 2024 capital expenditures for each of the vehicles, specialized tools, and equipment categories.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

To clarify, Equipment capital expenditures consists of only two categories: (1) Vehicles and (2) (Specialized) Tools and Equipment. Equipment capital expenditures for 2014 to 2019P and forecast expenditures for 2020-2024 are provided in Tables 1 and 2 below.

Table 1: FBC Vehicles, Tools and Equipment Capital Expenditures, 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Vehicles	1,311	1,736	2,040	2,098	2,570	2,100
Tools and Equipment	432	396	497	537	529	538
Total	1,744	2,132	2,536	2,636	3,099	2,638

Table 2: FBC Vehicles, Tools and Equipment Capital Expenditures, 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Vehicles	$ 2,256	$ 2,700	$ 2,770	$ 2,695	$ 3,090	$ 2,785
Tools and Equipment	535	707	568	579	591	603
Total	$ 2,791	$ 3,407	$ 3,338	$ 3,274	$ 3,681	$ 3,388

The main factor contributing to the increases in costs for Fleet Vehicles has been the change in the US$/CDN$ exchange rate starting in 2015. The specialized assets utilized by FBC are almost exclusively built and manufactured in the United States and Fleet Vehicles expenditures in the proposed MRP reflect a further increase in price due to the change in the US$/CDN$ exchange rate.

The increase in Tools and Equipment in 2020 is for the acquisition of an underground cable puller. The cable puller will primarily be used for completing replacements of underground conductor during customer outages.

59.1.1 For each category, please explain the main factors contributing to the increases in costs for each of the three categories during the proposed MRP term compared to the Current PBR Plan term.

Response:

Please refer to the response to BCUC IR 1.59.1.

59.2 Please explain why the 2020 Facilities capital expenditures are forecast to increase significantly compared to the average 2017-2019 expenditures.

Response:

The 2020 Facilities capital expenditure is forecast to increase compared to the average 2017-2019 expenditures due to a proposed addition to an existing building. The 2017-2019 Facilities capital expenditures are focused on the sustainment of existing buildings assets and not additions. For the 2020 year, the Facilities expenditures includes an increase of $1.264 million from the 2019 forecast. The increase primarily relates to a proposed renovation to the Oliver District Office to increase the size of the building by approximately 2,000 sq. ft. There is currently insufficient space in the office for the work crews; the renovation will provide a dedicated work crew mustering area.

59.2.1 Please also explain why the Facilities expenditures are then forecast to decrease in 2021 compared to 2020 and stay the same for the remainder of the proposed MRP term.

Response:

The Facilities expenditures are forecast to decrease in 2021 compared to 2020 as the proposed Oliver building addition will be completed in 2020.

59.3 Please provide a breakdown and description of Facilities capital expenditures for the proposed MRP term and explain how FBC forecasts these expenditures.

Response:

The table below outlines the Facilities capital program and associated forecast expenditures over the 2020-2024 period. FBC closely tracks the estimated useful life of its assets through its asset registry and performs regular maintenance cycles. Closer to the asset replacement time, Facilities assesses the condition of the asset based on maintenance records and subject matter experts condition assessments, to confirm it is in need of replacement.

Facilities is currently in the process of implementing the AIP Copperleaf C55 software program (identified on page C-53 of the Application) that will support the current manual process related to the optimization of the Facilities capital portfolio. The new program will support consistent quantification of benefits, risk mitigation, and optimization based on the value measure framework, as discussed in Section C3.2 of the Application.

Facilities 2020-2024 ($000s)	2020	2021	2022	2023	2024
Building Disposal/Additions	$ 1,299	$ 346	$ -	$ 100	$ -
Finish & Fixture Replacements	250	300	496	396	396
Building Envelope	400	700	700	700	700
HVAC/Mechanical Equipment	300	200	300	300	300
Yard Rehabilitation	350	250	300	300	300
Security	365	200	200	200	300
Furniture & Equipment	250	300	300	300	300
Emergency Capital	50	50	50	50	50
Total	**$ 3,264**	**$ 2,346**	**$ 2,346**	**$ 2,346**	**$ 2,346**

59.4 Please re-create Table C3-40 on page C-104 of the Application to show the information systems capital expenditures for actual years' 2014 through 2018

and projected 2019 and the formula capital expenditures for years' 2014 through 2019.

Response:

Please refer to the response to BCUC IR 1.10.1 regarding the determination of capital formula amounts. For this reason, FBC is not able to provide formula allowed capital expenditures for the years 2014 through 2019.

Information Systems capital expenditures for 2014 to 2019P are provided in the table below.

	2014	2015	2016	2017	2018	2019P
Information Systems Sustainment	$ 2,901	$ 3,590	$ 3,100	$ 5,044	$ 3,873	$ 3,684
Application Enhancements	1,003	715	444	660	846	815
Cybersecurity	-	-	1	1,531	107	3,731
Business Technology Applications	1,212	887	1,523	1,745	2,352	2,357
Total	$ 5,116	$ 5,192	$ 5,067	$ 8,980	$ 7,177	$ 10,587

60.0 Reference: FBC CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4.2, pp. C-106 – C108

FBC Major Capital Projects

On pages C-107 – C-108 of the Application, FBC provides a Forecast Construction Timeline for certain identified Major Capital Projects.

60.1 For the two projects which have already been approved by the BCUC (i.e. Upper Bonnington Old Units Refurbishment and Corra Linn Spillway Gate Replacement), please provide the following information:

- Approved and actual/projected capital cost;
- Construction start date and anticipated in-service date;
- Whether or not the project is expected to be delivered on-time and within the defined budget; and
- If the project is not expected to be delivered on-time and/or within the defined budget, the time and/or budget variances and a description of the cause(s) of the variances.

Response:

Corra Linn Spillway Gate Replacement Project

On February 7, 2017, the BCUC approved a $62.694 million budget for the Corra Linn Spillway Gate Replacement project. In the 'FBC Corra Linn CPCN C-1-17 Compliance Filing – Contract Finalization Report CONFIDENTIAL' (Contract Finalization Report) submitted to the BCUC on April 4, 2018, FBC reported that upon completion of detailed engineering, the revised project budget increased to $66.844 million. Construction commenced on site June 4, 2018, the forecasted in-service date is Q4, 2021, and the project is forecast for completion at $66.844 million.

As outlined in the Contract Finalization Report, a major project risk is the condition of the concealed components surrounding each of the spillway gates. The arrangement of the dam is such that the spill gates could not be isolated and therefore, the condition of the concealed components could not be assessed during the engineering phase. Based on an inspection at a similar facility, FBC made allowances in the FBC held contingency to address the concealed components as follows:

Sill Beam – The scope of work captured in the contract included installing 14 new sill plates on top of the existing sill beams and to procure a spare sill beam should one need to be replaced. Contingency was added to the project to capture the costs of labour to install one sill beam and to replace it.

Seal Face - The scope of work captured in the contract included refurbishing 28 existing seal faces and to procure two spare seal faces (two are required per spillway gate) should they need to be replaced. Contingency was added to the project to capture the costs of labour to replace both seal faces and to replace them.

Roller Path - The scope of work captured in the contract included assessing 28 roller paths and to procure specialized steel to build one roller path should it need to be replaced. Contingency was added to the project to account for labour to refurbish the roller paths, labour to fabricate and install the roller path and material costs to replace the specialized steel.

During the Open Book Phase (OBP) of the project, pass/fail criteria was established within the technical specification for all of the concealed components. Upon inspection of spillway gates 9, 10 and 11 (the first set of gates being replaced) concealed components, all three (3) sill beams and all six (6) seal face and roller paths were found in poor condition and met the "fail" criteria outlined within the technical specification, requiring replacement. The added scope of work to correct the concealed conditions is currently underway as an executed change order under the contract. The impact to budget and schedule is estimated as follows;

Item	Financial Impact	Schedule Impact
Sill Beams	$0.315m/3 gate	5 weeks/3 gate
Combined Roller Path and Seal Path	$1.762m/3 gate	15 weeks/3 gate
Total	$2.077m	20 weeks

The result of the change in schedule is an approximate $1.16 million which is not included in the $2.077 million. There are currently other project delays such as the late arrival of the Semi Gantry which HMI is responsible for, the impacts of which are not yet known.

Replacing the concealed components on Spillway gates 9-11 will utilize the majority (>50 percent) of FBC held contingency and will push the project completion date into Q1, 2022. FBC and HMI will continue to seek efficiencies as the project progresses to reduce the impact to the schedule.

Upper Bonnington Old Units Refurbishment

On January 20, 2017, the BCUC, through Order G-8-17, approved a $31.783 million budget for the Upper Bonnington Old Units Refurbishment project. Construction commenced onsite June 2017 and the forecasted in-service date for Unit 2 (the last of the 4 generating units to be refurbished) is Q4 2020, with the balance of plant scope of work taking place into Q1 2021. The project remains on schedule and within 7.5 percent of the defined project budget.

With approximately 50 percent of the project complete (2 unit refurbishments complete) and the majority of the costs confirmed on the third unit currently being upgraded, the financial forecast for the remainder of the project has been updated using the most recent data. The project is now forecast to cost $34.2 million which is approximately $2.4 million (7.5 percent) higher than approved in Order G-8-17. The primary drivers behind the $2.4 million increase are higher than estimated costs to refurbish the concealed components and an increase in market pricing. Following a competitive tendering process, the generator refurbishment work was awarded to the lowest bidder; however, the cost is approximately $1.4 million higher than originally estimated. The remaining $1 million is the net cost of multiple smaller variations.

60.2 Please confirm, or explain otherwise, that the Grand Forks Terminal Station Reliability Project is currently being reviewed by the BCUC through a public hearing process.

Response:

Confirmed. The evidentiary phase of the review is complete and FBC is awaiting a decision on the application.

60.2.1 Please provide the forecast capital cost of the project.

Response:

The forecast cost for the preferred option is $13.2 million, inclusive of AFUDC and cost of removal.

60.3 For the remaining identified Major Project, the Kelowna Bulk Transformer Addition, please provide, as a new Appendix, a one-page summary to include the project name, need, alternatives, benefits, scope, capital cost and accuracy level, construction start date, in-service date, consultation, public interest issues, risks, and a description of the project.

Response:

The requested information is provided in Attachment 60.3.

60.3.1 Please confirm, or explain otherwise, that FBC intends to seek a CPCN for this project.

Response:

Confirmed.

60.4 Please clarify if the list of Major Projects identified on pages C-107 and C-108 of the Application represent all of FBC's anticipated Major Projects for the proposed MRP term.

Response:

Not confirmed. The Major Projects identified in the Application are examples of projects that may arise during the term of the proposed MRP. FBC has identified, and is investigating, other projects that may be brought forward during the MRP term. At the current preliminary stage of investigation, FBC believes it is premature to identify or discuss projects that may not proceed, and they do not affect the approvals sought in this Application.

60.4.1 If no, please provide a list of all proposed Major Projects expected during the proposed MRP term. For each additional project identified, please provide, as a new Appendix, a one-page summary to include the project name, need, alternatives, benefits, scope, capital cost and accuracy level, construction start date, in-service date, consultation, public interest issues, risks and a description of any additional projects identified.

Response:

Please refer to the response to BCUC IR 1.60.4.

60.5 Please provide a breakdown, in tabular form, of all Major Projects FBC planned to deliver in the Current PBR Plan term.

Response:

As provided in Section 5.7 of the FBC 2014-2018 PBR Application (pp. 227-231), below is a table of major projects FBC listed as being considered at the time of filing, covering the years 2014 through 2018. FBC notes that, consistent with this Application, FBC did not seek approval of these projects in the 2014-2018 PBR Application, such that the information provided in that proceeding was for additional information purposes only.

Project Name	Description
Kelowna Bulk Transformer Capacity Addition	The FA Lee Terminal Station is one of two terminal stations serving Kelowna and the surrounding area. If an outage occurs on one of the two FA Lee Terminal Transformers, the load on the remaining transformer can exceed its emergency overload rating during the summer peak, a condition that violates BC Mandatory Reliability Standard TPL-002. The addition of a new power transformer is necessary to ensure adequate capacity in the Kelowna area in the event of such an outage.
Grand Forks Transformer Addition	The Grand Forks area 63 kV system does not have adequate backup capability in the event of an outage during peak load to the Grand Forks Terminal transformer due to the extremely poor condition of the existing 63 kV lines from Warfield which provide the source of backup supply. The project will install a second transformer at the Grand Forks Terminal, remove more than 40 km of the 63 kV lines and repurpose a portion of them to distribution voltage.
Ruckles Substation Upgrade	The Ruckles Substation in Grand Forks had numerous issues related to geography and aging equipment, including being subject to flooding during spring runoff on several occasions. The substation was required to be rebuilt on the existing site.
New Central Okanagan Station	A new substation in the Central Okanagan was under consideration to replace the existing Kaleden substation due to concerns regarding its age and capacity.

Project Name	Description
Grand Forks to Warfield Fibre Installation	FBC's fibre optic network was not contiguous from end to end of its system, with a gap between Grand Forks and Warfield. FBC did not have any high speed communications facilities linking the Okanagan to the Kootenays, which impacted operational communications. The project proposed to construct a new fibre optic cable between the Grand Forks and A.S. Mawdsley Terminal Stations on the existing 161 kV transmission line.
Corra Linn Spillway Concrete and Spill Gate Rehabilitation	Changes to the *BC Dam Safety Regulations* resulted in a reclassification of the Corra Linn dam from the Very High to the Extreme category. An evaluation of the consequences of failure for the dam was undertaken, followed by an evaluation of its ability to withstand a seismic event and condition assessments of the spillgates and other components of the dam prior to filing a CPCN application to remediate deficiencies.
Kootenay Long Term Facilities Strategy	The project was to address issues at FBC's facilities in the Kootenay area, including the age and condition of the Administration Office and Warehouse at the South Slocan Generation Site and the Castlegar District Office, and the System Control Centre at Warfield, which required replacement due to MRS compliance concerns and increased space requirements. A new, centralized regional facility was determined to be the most cost-effective solution to address these issues.
Upper Bonnington Units 1,2,4 Refurbishment	The refurbishment of Upper Bonnington Units 1, 2, and 4, which had been constructed between 1905 and 1916 was required for the continued safe and reliable operation of the units, and to preserve FBC's capacity and energy entitlements as provided for under the multi-party Canal Plant Agreement, for the benefit of customers.

60.5.1 For each Major Project, please provide the following: (i) approved and actual capital cost; (ii) anticipated construction start date and in-service date; (iii) whether or not the project was delivered; (iv) if the project was delivered, whether it was delivered on-time and within the defined budget; and (v) for any projects that were not delivered on-time and/or within the defined budget, please provide the time and/or budget variances and a description of the cause(s) of the variances.

Response:

The list of potential major projects provided in the FBC 2014-2018 PBR Application was prepared at a high level and provided for reference purposes only. These projects were in the preliminary stages of development at the time of the FBC 2014-2018 PBR Application and were

provided to demonstrate the type of Major Project that may be executed during the Current PBR Plan term. Please refer to the response to BCUC IR 1.60.4 for a discussion of Major Projects under the MRP Application. As with the proposed MRP, Major Capital projects were excluded from FBC's 2014-2018 PBR Application.

The table below provides the requested information for those projects identified in the 2014-2018 application. Capital costs include AFUDC and costs of removal.

Project Name (2014 and current)	Forecast Capital Cost ($ million)	Actual/Projected Capital Cost ($ million)	Anticipated Start Date/In-service Date	Actual In-Service Date	Description of Variances
Kelowna Bulk Transformer Capacity Addition	approx. $20	n/a	2020/ 2022	n/a	FBC expects to file a CPCN application for this project in 2019.
Grand Forks Transformer Addition (Grand Forks Terminal Reliability Project)	$13.2	$13.2	Q3 2109/ Q3 2020	n/a	BCUC approval pending.
Ruckles Substation Upgrade	$8.3	$6.4	May 2017/ Q3 2018	June 2018	Elimination of 4 kV voltage components by assisting large customers to advance voltage conversion. Favourable cost of equipment procurement and release of contingency.
New Central Okanagan Station	n/a	n/a	n/a	n/a	Project was not delivered during the Current PBR Plan term because load growth was lower than expected; capacity constraints did not materialize.
Grand Forks to Warfield Fibre Installation	n/a	n/a	n/a	n/a	Project is not required because FBC has entered into a long term contract for fibre with a third party.

Project Name (2014 and current)	Forecast Capital Cost ($ million)	Actual/Projected Capital Cost ($ million)	Anticipated Start Date/In-service Date	Actual In-Service Date	Description of Variances
Corra Linn Spillway Concrete and Spill Gate Rehabilitation (Corra Linn Dam Spillway Gate Replacement)	$66.8	$66.8	Feb. 2018/ Sept. 2021	Q4 2021	Please refer to the response to BCUC IR 1.60.1.
Kootenay Long Term Facilities Strategy (Kootenay Operations Centre)	$20.1	$20.1	May 2016/ Nov. 2017	Sept. 2017	No material variances.
Upper Bonnington Units 1,2,4 Refurbishment (UBO Old Units Refurbishment)	$31.8	$34.2	Jun 2017/ Apr 2020	Q1 2020	Please refer to the response to BCUC IR 1.60.1.

60.5.2 If a Major Project was not delivered in the Current PBR Plan term, please explain why and explain whether FBC proposes to deliver the project in the proposed MRP term.

Response:

Please refer to the response to BCUC IR 1.60.5.1.

60.6 Please compare the number of Major Projects and the total capital cost of these projects during the Current PBR Plan term to the proposed MRP term.

Response:

Tables 1 and 2 below show the number and cost estimate of anticipated Major Projects that were identified for separate approval at the outset of the Current PBR Plan term and those that FBC has included in its Application for the proposed MRP Term. The cost estimate for the Kelowna Bulk Transformer Station is preliminary and are likely to change (please refer to BCUC IR 1.49.1). When FBC proceeds with a CPCN application for this project, it will include scope definition and cost estimates consistent with the BCUC's CPCN guidelines.

For consistency with the presentation of Regular capital projects, costs of removal and AFUDC are excluded.

Table 1: FBC Major Capital Projects, 2014 – 2019P

	2014	2015	2016	2017	2018	2019P	Project Total
Advanced Metering Infrastructure	$ 13,547	$ 23,773	$ 3,594	$ 613	$ -	$ -	$ 46,647
Kootenay Operations Centre	800	(23)	7,166	9,550	466	-	17,959
UBO Old Units Refurbishment	$ -	$ -	$ -	$ 8,017	$ 8,249	$ 7,435	23,701
Ruckles Substation Rebuild	-	-	-	3,645	2,179		5,824
Corra Linn Spillway Gate Replacement	-	-	-	3,799	12,261	18,934	34,994
Grand Forks Terminal Transformer Addition	-	-	-	-	-	1,793	1,793
Total	$ 14,349	$ 23,750	$ 10,758	$ 25,625	$ 23,155	$ 28,162	$ 130,919

Table 2: FBC Major Capital Projects, 2020 – 2024

	2020	2021	2022	2023	2024	Project Total
UBO Old Units Refurbishment	$ 5,466	$ 356	$ -	$ -	$ -	$ 5,822
Kelowna Bulk Transformer Addition	5,556	7,250	6,633	-	-	19,440
Corra Linn Spillway Gate Replacement	11,107	8,740	501	-	-	20,348
Grand Forks Terminal Transformer Addition	4,970	1,349	-	-	-	6,319
Total	$ 27,098	$ 17,695	$ 7,135	$ -	$ -	$ 51,928

60.7 Please explain whether any of the Major Projects included in the proposed MRP were originally included in the Current PBR Plan's Sustainment or Other Capital categories.

Response:

The four Major Projects identified in the Application are:

- Upper Bonnington Old Units Refurbishment;
- Corra Linn Spillway Gate Replacement;

- Grand Forks Terminal Station Reliability; and
- Kelowna Bulk Transformer Addition.

None of these Major Projects were included in the Current PBR Plan as Sustainment or Other capital. Each of the projects was identified in Section 5.7 of the FBC 2014-2018 PBR Application as projects for which FBC intended to file CPCN applications and was therefore excluded from formula capital under the Current PBR Plan.

The Corra Linn Spillway Gate Replacement Project was filed as a CPCN and the Kelowna Bulk Transformer Addition requires CPCN approval because it is expected to exceed the CPCN materiality threshold of $20 million[50].

In 2016, FBC sought clarification of the treatment under the Current PBR Plan of four additional capital projects, including the Upper Bonnington Old Units Refurbishment project and the Grand Forks Terminal Station Reliability project (then referred to as the Grand Forks Transformer Addition). The BCUC Panel concluded that

> (s)ince these projects were identified as CPCN projects at the time, these capital expenditures were not included in the proposed and approved formula-driven base capital.[51]

60.7.1 If yes, please provide a list of any such projects or programs and provide a rationale for the re-categorization.

Response:

Please refer to the response to BCUC IR 1.60.7.

[50] Order G-120-15 approved the CPCN threshold of $20 million and set the same threshold for the exclusion of projects from formula capital under the Current PBR Plan.

[51] Appendix A to Order G-80-16, page 4.

E. ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

61.0 Reference: FEI DELIVERY REVENUES

Exhibit B-1, Section C4.2, p. C-109; Exhibit B-1-1, Appendix B2, pp. 1–3, 12

FEI Forecasting Method Study

FEI provides the following table on page 1 of Appendix B2:

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

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

On page 3 of Appendix B2, FEI states that it "recommends the adoption of the ETS [Holts Exponential Smoothing] method for residential and commercial use rate forecasting and the continued use of the existing forecast method for commercial customer additions."

FEI provides the following analysis of the pros and cons of each method on page 12 of Appendix B2:

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

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

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

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

61.1 Please provide an annual cost comparison (both O&M and capital if applicable) of the existing forecasting method and the ETS method.

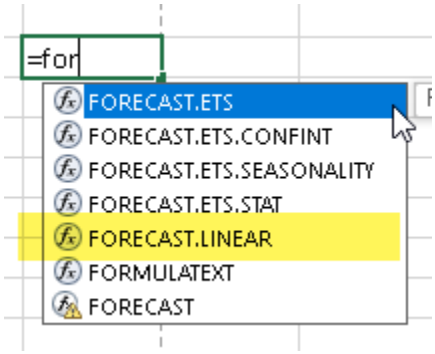
Response:

The annual cost (O&M and capital) to implement either the ETS method or the existing method are identical.

Both the ETS method and the existing method are considered time series forecasts and require the same historical actual weather normalized data from our existing database servers. Both methods require a forecast analyst to gather the same data into an Excel spreadsheet. There is no difference in time, effort or costs for gathering the required data for either method.

Both methods use the same version of Microsoft Excel to complete the calculations. The required Excel version is already installed and in use. There are no additional capital or O&M cost implications for using ETS.

When creating the forecast spreadsheets the two methods are both easily accessed as shown in the following screen shot from Microsoft Excel. The formula for the ETS forecast is shown in blue while the formula for the existing method is shown in yellow.



The cell formula for the ETS method is:

=forecast.ets

The cell formula for the existing method is:

=forecast.linear

There is no measurable difference in the time, effort or cost to produce one forecast compared to the other.

61.2 Please compare the length of time to prepare the annual load forecasts under each method and explain the cause(s) of any differences.

Response:

Please refer to the response to BCUC IR 1.61.1.

61.3 Will FEI's proposed approach of utilizing the ETS method for forecasting use rates and utilizing the existing method for forecasting commercial customer additions be more costly and/or more time consuming than if FEI were to continue using the existing methods for all of its forecasting? If yes, please quantify and explain the differences. If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.61.1.

61.4 Please explain whether FEI considers the ETS method to be less transparent than the existing method and, if so, the potential implications of this lack of transparency (e.g. lack of stakeholder acceptance, reduction in effectiveness of the regulatory review process).

Response:

FEI does not consider the ETS method to be less transparent than the existing method.

FEI believes that while the ETS method is slightly more complex from a text book perspective, it is no less transparent than the existing method because both are identically implemented in Excel as cell formulas that can easily be executed by anyone with a modern version of Microsoft Excel.

61.5 Please explain what characteristics/criteria FEI placed the greatest weight on when selecting the forecasting method for customer use and customer additions and why FEI considers this weighting appropriate.

Response:

FEI placed the greatest weight on average forecast performance as measured by the 2012-2018 demand variance MAPE. FEI believes that when comparing methods with identical operational costs, the method that produces the lowest mean demand variance should be used.

FEI considered the following criteria in the order shown:

1. Performance
    a. The ETS method had to perform as well or better in terms of MAPE scores to be considered. This is the most important criteria.
2. Consistency of performance
    a. The ETS method had to perform consistently. In the case of commercial use rates the ETS method performed better than the existing method in all test years.
3. Consistency of methods
    a. The methods used for calculating use rates should be consistent between rate classes for operational efficiency. Being able to use ETS for rate schedules 1, 2, 3 and 23 and in all regions was the third highest ranked criteria.
4. Ease of implementation
    a. FEI had to be able to implement the ETS method without a significant increase in staff effort or the requirement for new data sets or software tools. The ETS method as implemented in Microsoft Excel achieved this goal.
5. Making use of the entire data set
    a. The ETS method dynamically weights all the available data points. FEI believes this is a desirable characteristic compared to using averaging or regression methods that rely on a fixed number of data points, such as a three-year average.

61.6 Please explain the implications to ratepayers if the performance of the ETS method for forecasting Vancouver Island and Whistler customer use is shown to be poor. As part of this response, please explain what actions, if any, FEI would propose to take if such a situation occurs.

Response:

FortisBC believes the impact of the performance of the ETS method for forecasting Vancouver Island and Whistler customer use would be minimal, even if shown to be poor. The results from the Vancouver Island and Whistler forecasts are aggregated with the Lower Mainland, Inland and Columbia forecasts to arrive at the final forecast. As a result, poor forecast performance in Vancouver Island or Whistler would have a minimal impact on rates. Further, forecast variances relating to demand are captured in deferral accounts and subsequently returned to or recovered from customers, eliminating the impacts of such variances.

If forecasting for Vancouver Island and Whistler customer use is shown to be consistently poor, FEI would bring forward a recommendation for any needed adjustment to the forecasting method in future Annual Reviews or Revenue Requirements applications.

61.6.1 Please respond to the same question as above for the Fort Nelson service area.

Response:

FortisBC will monitor the performance of the ETS method in Fort Nelson and will evaluate, if needed, for Fort Nelson's next revenue requirements application.

On page 2 of Appendix B2, FortisBC states the following:

> Using its existing method for calculating residential 1 use rates, FEI's mean absolute percent error (MAPE4) for the residential demand forecast over the period from 2012-2018 was 2.7 percent.
>
> Using its existing method for calculating commercial use rates, FEI's MAPE for the commercial demand forecast over the period from 2012-2018 was 2.4 percent.

Using its existing method for calculating commercial customer additions, FEI's MAPE for the commercial demand forecast over the period from 2012-2017 was 2.4 percent.

61.7 Please explain why the MAPE for the demand forecast was calculated over the period 2012-2018 for the residential and commercial use rates, whereas the MAPE for the demand forecast was calculated over the period of 2012-2017 for commercial customer additions.

Response:

For commercial customer additions, the reference to "2012-2017" was a typographical error. The MAPE of 2.4 percent was calculated using data from 2012-2018. This error will be corrected in an Errata to be filed in the near future.

61.7.1 If available, please provide the results of the demand forecast along with the MAPE for commercial customer additions for the 2012-2018 period.

Response:

Please refer to the response to BCUC IR 1.61.7.

62.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.4.2.2, p. C-112

Variable LNG Production Costs

On page C-112 of the Application, FEI states: "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."

62.1 Please explain if FEI anticipates future expansions of Tilbury to occur during the proposed MRP term.

Response:

FEI is evaluating the opportunity to expand the Tilbury site to include the construction of onshore cryogenic piping which would connect the newly constructed Tilbury LNG storage tank to a marine jetty (constructed and owned by others). The timeframe for construction of this onshore piping would be 2020 and 2021, but is subject to the third party securing external and regulatory approvals for the marine jetty, including an Environmental Assessment Certificate, to proceed. FEI has not made a determination regarding the impact on Base O&M, capital expenditures or load/revenue.

Secondly, FEI continues to evaluate the potential for further expansion at the Tilbury site, including additional liquefaction and storage capacity, which is dependent on market conditions. However, FEI has not made a determination regarding the timeframe or impact on Base O&M, capital expenditures or load/revenue associated with these initiatives to date.

Any impacts will be brought forward for discussion and review at future Annual Reviews.

62.1.1 If yes, please provide a detailed explanation of the anticipated expansions, including the timing of such expansions, and the potential impact on O&M and capital expenditures and on load/revenue.

Response:

Please refer to the response to BCUC IR 1.62.1.

63.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.1, pp. C-109 – C-119, Table C4-1; Exhibit B-2, p. 6, Appendix A

Forecast Cost and Revenue Items

Table C4-1 on page C-118 of the Application outlines FortisBC's proposals with respect to the treatment of variances in FEI and FBC's annual revenue requirements.

On page C-109 of the Application, FortisBC states that "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."

In Appendix A of the Workshop Materials, FortisBC provides a side-by-side comparison of the treatment of all variances under the proposed MRPs and the Current PBR Plans. FortisBC states on page 6 that it identified with yellow highlighting where variance treatments in the proposed MRPs are different from the Current PBR Plans.

On page 2 of the Workshop Materials, FortisBC summarizes the five FBC/FEI items it proposes to be subject to earnings sharing as follows:

FBC/FEI Items Subject to Earnings Sharing	Description
Gross O&M: Indexed based O&M variances	Variances in index-based O&M
Depreciation: Other depreciation variances	Variances in depreciation expense from Regular Capital (other than those driven by depreciation rate variances).
Other Revenues: All other revenue / income variances	Variances in other revenue not subject to a separate deferral account, such as connection fees, late payment fees, etc.
Interest Expense: Other interest variances	Variances in interest expense other than those driven by interest rate variances.
Income Tax: Other income tax variances	Variances in income tax expense other than those driven by income tax rate variances.

63.1 Please explain and provide a list of the factors or criteria which FortisBC considered when determining which variances in cost and revenue items should be: (i) "flowed through in future revenue requirement"; (ii) "subject to earnings or sharing"; or (iii) subject to other treatment. If there are different considerations for each, please specify.

Response:

As discussed in Section 1.1, the Proposed MRPs build on the successes of FEI's and FBC's Current PBR Plans, while making changes to respond to the challenges experienced and stakeholder feedback. The proposal to change the treatment of variances is linked to

stakeholder feedback regarding the complexity of the existing earnings sharing mechanism and dead band adjustment and FortisBC's previous experience with its multi-year rate plans.

The criteria that the Companies used to determine which variances would (i) flow through in future revenue requirements, (ii) be subject to earnings or sharing, or (iii) be subject to other treatment were based on (i) whether the treatment aligned with the proposed earnings sharing mechanism, (ii) consideration of which costs are controllable, and (iii) whether the costs drive incremental revenues or are more generally supportive of Clean Growth initiatives. This is why the Companies are proposing to change the treatment of only four (five for FBC) of the approximately 20 possible cost and revenue variances.

First, the changes, along with the elimination of the dead band, support a more common and simplified earnings sharing mechanism by allowing variances related to capital spending to flow to the bottom line[52], thereby incenting the Companies to become more efficient with regard to capital spending and returning half of those efficiencies to customers.

Second, the Companies continue to believe that uncontrollable costs should be subject to deferral account treatment.

Third, there continue to be costs that continue to be flowed through to future revenue requirements that drive incremental revenue, such as NGT, or are related to Clean Growth, such as RNG.

63.1.1 To the extent that "controllability" is a factor or criterion, please discuss how FortisBC defines items as either "controllable" or "uncontrollable" in nature, and the treatment of "partially controllable" cost and revenue items.

Response:

Please refer to the response to BCUC IR 1.63.2.

[52] With the exception of interest rate and income tax rate variances which are related to factors outside of FortisBC's control.

63.1.2 Please rank the factors or criteria by the order of importance which they are considered and explain the rationale for the rankings.

Response:

FortisBC does not consider there to be a ranking of factors by importance.

63.2 Based on the factors or criteria discussed in the IR response above, for each cost and revenue item where variances are proposed to be flowed through in future revenue requirements (i.e. either to be captured in the Flow-through deferral account or in a previously approved deferral account), please explain how the factors or criteria have been met. Please provide separate discussions for each item for FEI and FBC.

Response:

In this Application FortisBC's approach was to maintain flow-through/deferral account treatment that had already been approved except where changes were required to increase the incentives around Other Revenue and Regular Capital spending. This was explained in the response to BCUC IR 1.63.1. This means that there were no changes to the treatment of items with the exception of:

- Controllable depreciation, interest and tax variances (driven by regular capital spending); and
- Other Revenue variances.

Since there has been no change in the approved treatment of the remaining items, FortisBC did not undertake a line-by-line review of the reasons why the items have previous been approved for deferral account treatment. However, FortisBC has prepared the following list of flow-through/deferral items and provides below the list a discussion of why they have that treatment, which is primarily related to the ability to control the costs, and whether they drive incremental revenues.

Revenues – rates and use rates are not generally controllable; FortisBC is able to influence customer additions but separating this from the remaining revenue variances can be more challenging. FortisBC already has an incentive to add customers, as growing the customer base will increase the O&M funding and also the Growth capital funding.

Cost of Gas/Power Supply – FEI has an incentive to mitigate these costs to the extent possible through the GSMIP, and FBC has proposed the PSI. The remaining variances are largely driven by weather or external market factors outside of the control of the Utilities.

BCUC fees/Pension & OPEB costs/Insurance Premiums/Integrity Digs – the rationale is discussed on page C-111 of the Application as being largely outside the control of the Utilities.

NGT stations/biomethane/variable LNG production/EV charging stations – the rationale is discussed on pages C-111 through C-113 of the Application as being related to driving incremental revenues (which are flow-through) and supporting a transition to a lower carbon energy system.

Property tax/interest rate/income tax rates – the rationale is discussed on pages C-114 to C-115 of the Application as being outside the control of the utilities.

63.3 Based on the factors or criteria discussed in the IR response above, please explain how each of the five FBC/FEI items proposed to be subject to earning sharing have met the factors or criteria for that variance treatment. Please provide separate discussions for each item for FEI and FBC.

Response:

The factors considered in FortisBC's proposed earnings sharing are the same for both FEI and FBC. Please refer to the response to BCUC IR 1.63.1.

63.3.1 Please explain why FortisBC considers it appropriate to change how the following are treated in the proposed MRP compared to the Current PBR Plans and explain at a high level the implications for FortisBC and for ratepayers:

- "variances in depreciation expense (other than those driven by depreciation rate variances)";
- "variances in interest expense other than those driven by interest rate variances"; and

- "variances in income tax expense other than those driven by income tax rate variances".

Response:

Please refer to the response to BCUC IR 1.63.1.

63.4 Please explain why FortisBC considers that fewer variances should be flowed through in future revenue requirements and more variances should be subject to earnings sharing in the proposed MRPs compared to the Current PBR Plans.

Response:

Please refer to the response to BCUC IR 1.63.1.

63.5 For each of FEI and FBC, please provide the following analysis for the four categories which FortisBC proposes to change the treatment during the proposed MRP (i.e. other depreciation variances, other interest variances, other income tax variances, and all other revenue/income variances):

- Annual forecast expense/revenues for each of 2014 through 2019 for each of the four categories (with regard to Other Revenue, please separately show the forecast for each category of Other Revenue);
- Annual actual expense/revenues for each of 2014 through 2018 and projected for 2019 for each of the four categories (with regard to Other Revenue, please separately show the actual amount for each category of Other Revenue);
- Annual and cumulative forecast versus actual variance for each category;
- Annual and cumulative impact on achieved ROE and earnings sharing of the variances based on the approved method in the Current PBR Plan and the proposed method for the MRPs, and the resulting difference in rate impacts.

Response:

FortisBC has responded to this question using the years 2014 through 2018 as 2019 actuals are not yet known and the Companies have not yet produced a projection. FortisBC will be preparing 2019 projections for the Annual Reviews for 2020 Rates.

FortisBC has endeavoured to respond to this question recognizing that to be responsive to the last point requires recalculating historical BCUC Annual Report results (2014 through 2018) to reflect the proposals in the MRPs with respect to the treatment of variances, effect on achieved ROE, earnings sharing and rates. The following is a list of the assumptions that were used:

- Variances from the five items listed in the preamble fall to earnings;
- The total depreciation variance was used except for the Tilbury Expansion depreciation variance which was removed from the 2018 total depreciation variance;
- The total interest expense variance was used although a portion of that variance will be related to short term interest rate variances and long term debt variances which are currently captured in the Flow-though deferral account and will continue to be captured in the Flow-through deferral account; and
- The total tax variance was used, although some of the tax variance will be associated with items that will continue to be accounted for in the Flow-through deferral account.

When recalculating achieved ROE, earnings and earnings sharing, the changes in the aforementioned items in one year affect the rate changes that customers experience in the following year. This occurs because the changes in one year are posted to the Flow-through deferral and the Earnings Sharing deferral accounts. Those accounts are then amortized in the following year and affect rates. Because of this, this response does not include a rate impact for 2014, the first year of the Current PBR Plans.

The following tables include the annual forecast and actual expenses/revenues for 2014 through 2018 for each of the four categories requested above, including the annual variance and cumulative total variance for FEI and FBC. The amounts in these tables are natural sign.

	2014			2015			2016		
FEI	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Other Revenue									
Late Payment Charge	(2,089)	(2,842)	(753)	(2,542)	(2,545)	(3)	(2,314)	(2,326)	(12)
Connection Charge	(2,636)	(2,550)	86	(3,033)	(3,123)	(90)	(3,060)	(3,253)	(193)
NSF Returned Cheque Charge	(79)	(33)	46	(89)	(76)	13	(88)	(81)	7
Other Recoveries	(284)	(249)	35	(202)	(243)	(41)	(202)	(271)	(69)
NGT Tanker Rental Revenue	-	(158)	(158)	(215)	(151)	64	(209)	(176)	33
NGT Overhead and Marketing Recovery	(180)	(233)	(53)	(227)	(252)	(25)	(263)	(298)	(35)
Depreciation on all Plant but Tilbury Expansion	124,667	124,977	310	163,962	163,084	(878)	170,348	168,824	(1,524)
Interest Expense	109,788	109,910	122	133,185	133,219	34	130,511	128,675	(1,836)
Income Taxes	41,517	41,856	339	49,002	52,834	3,832	46,173	52,501	6,328
Total	**270,704**	**270,678**	**(26)**	**339,841**	**342,747**	**2,906**	**340,896**	**343,595**	**2,699**

	2017			2018			Total
FEI	Forecast	Actual	Variance	Forecast	Actual	Variance	Variance
Other Revenue							
Late Payment Charge	(2,180)	(2,750)	(570)	(2,688)	(2,583)	105	(1,233)
Connection Charge	(3,118)	(3,139)	(21)	(3,148)	(2,875)	273	55
NSF Returned Cheque Charge	(76)	(91)	(15)	(80)	(80)	-	51
Other Recoveries	(243)	(229)	14	(288)	(269)	19	(42)
NGT Tanker Rental Revenue	(448)	(307)	141	(583)	(544)	39	119
NGT Overhead and Marketing Recovery	(332)	(346)	(14)	(320)	(325)	(5)	(132)
Depreciation on all Plant but Tilbury Expansion	168,190	166,339	(1,851)	177,092	175,686	(1,406)	(5,349)
Interest Expense	122,183	122,947	764	134,461	135,880	1,419	503
Income Taxes	35,651	40,654	5,003	50,137	56,649	6,512	22,014
Total	**319,627**	**323,078**	**3,451**	**354,583**	**361,539**	**6,956**	**15,986**

	2014			2015			2016		
FBC	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Other Revenue									
Apparatus and Facilities Rental	(4,156)	(4,820)	(664)	(4,380)	(4,604)	(224)	(4,467)	(4,754)	(287)
Contract Revenue	(1,385)	(2,076)	(691)	(1,544)	(1,948)	(404)	(1,808)	(1,821)	(13)
Transmission Revenue	(1,224)	(1,120)	104	(1,189)	(1,158)	31	(1,230)	(1,278)	(48)
Interest Income	(78)	(107)	(29)	(57)	(107)	(50)	(34)	(37)	(3)
Connection Charges	-	(619)	(619)	(470)	(656)	(186)	(496)	(599)	(103)
Other Recoveries	(738)	(201)	537	(632)	(572)	60	(142)	(141)	1
Depreciation	49,682	49,682	-	52,151	55,552	3,401	54,353	53,896	(457)
Interest Expense	42,656	40,304	(2,352)	39,648	39,273	(375)	38,906	38,040	(866)
Income Taxes	11,138	11,920	782	6,684	6,829	145	8,310	7,186	(1,124)
Total	**95,895**	**92,963**	**(2,932)**	**90,211**	**92,609**	**2,398**	**93,392**	**90,492**	**(2,900)**

	2017			2018			Total
FBC	Forecast	Actual	Variance	Forecast	Actual	Variance	Variance
Other Revenue							
Apparatus and Facilities Rental	(4,576)	(4,808)	(232)	(4,736)	(5,808)	(1,072)	(2,479)
Contract Revenue	(1,865)	(1,915)	(50)	(1,769)	(1,939)	(170)	(1,328)
Transmission Revenue	(1,179)	(1,190)	(11)	(1,170)	(1,111)	59	135
Interest Income	(24)	(43)	(19)	(16)	(29)	(13)	(114)
Connection Charges	(270)	(606)	(336)	(368)	(589)	(221)	(1,465)
Other Recoveries	(142)	(1,162)	(1,020)	(356)	(663)	(307)	(729)
Depreciation	56,046	55,980	(66)	58,408	58,802	394	3,272
Interest Expense	40,191	38,127	(2,064)	40,059	40,069	10	(5,647)
Income Taxes	10,849	12,201	1,352	9,633	12,545	2,912	4,067
Total	**99,030**	**96,584**	**(2,446)**	**99,685**	**101,277**	**1,592**	**(4,288)**

The following tables include the annual impact on achieved ROE, earnings sharing and customer rates of variances based on the approved method in the Current PBR Plans and the proposed method in the Application. A negative earnings sharing amount indicates an amount being returned to customers, whereas positive indicates an amount being recovered from customers. A negative difference in rates indicates a rate decrease; conversely a positive indicates a rate increase.

	2014			2015			2016		
FEI	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	9.20%	9.15%	-0.05%	9.19%	9.03%	-0.16%	9.28%	9.10%	-0.18%
Earnings Sharing	(3,657)	(4,191)	(534)	(4,599)	(3,913)	686	(5,162)	(4,996)	166
Change in Rates Including Energy						0.0%			-0.2%
Change in Rates Excluding Energy						-0.1%			-0.3%

	2017			2018			2019		
FEI	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	9.04%	8.88%	-0.16%	8.93%	8.67%	-0.27%			
Earnings Sharing	(2,943)	(1,857)	1,086	(995)	1,431	2,426			
Change in Rates Including Energy			-0.2%			-0.2%			-0.4%
Change in Rates Excluding Energy			-0.3%			-0.3%			-0.6%

	2014			2015			2016		
FBC	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	9.22%	9.52%	0.30%	9.26%	9.01%	-0.25%	9.38%	9.62%	0.24%
Earnings Sharing	(330)	(1,805)	(1,475)	(481)	686	1,167	(727)	(2,405)	(1,678)
Change in Rates Including Energy						0.4%			-0.4%
Change in Rates Excluding Energy						0.6%			-0.6%

	2017			2018			2019		
FBC	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	9.31%	9.52%	0.21%	9.29%	9.08%	-0.21%			
Earnings Sharing	(524)	(1,895)	(1,371)	(133)	357	490			
Change in Rates Including Energy			0.3%			0.3%			-0.1%
Change in Rates Excluding Energy			0.6%			0.5%			-0.1%

The following paragraphs sets out conclusions concerning the results in the above tables, which should be interpreted as directional only.

FEI

Using the proposals in the Application, four of the variances that would have been accounted for in the Flow-through deferral account and collected from/returned to customers now fall to

earnings. Generally, over the Current PBR Plan term those variances have been debits (actual costs greater than forecast). These cost variances that would have been collected from customers now fall to earnings, consequently FEI has a lower achieved ROE and the lower achieved ROE results in less earnings sharing for customers. However, customers see a decrease in rates in the following year because under the Current PBR Plan customers are responsible for 100 percent of the flow-through variances (generally debits) while under the proposed MRP, half of those cost variances are retained by the shareholder. Consequently, the decrease in the earnings sharing is more than offset by the decrease in the Flow-through, so customers experience rate decreases.

FBC

For FBC the variances that fall to earnings under the proposed approach oscillate between debits (costs) and credits (savings). When the variances are debits, the earnings sharing to customers decreases and the following year's rates decrease. When the variances are credits, the earnings sharing to customers increases and the following year's rates increase.

63.6 Based on Actual 2018 results, please compare and provide the supporting calculations for the proportion of FEI and FBC's total annual revenue requirements under the Current PBR Plans and under the proposed MRPs which will be: (a) flowed through; and (b) subject to earnings sharing during the term of the Proposed MRPs:

(i) including cost of gas (FEI) and power purchase expense (FBC); and

(ii) excluding cost of gas (FEI) and power purchase expense (FBC).

Response:

Please refer to the response to BCUC IR 1.63.5 (refer to Including Energy and Excluding Energy lines).

64.0 Reference: CAPITAL EXPENDITURES

Exhibit B-2, Workshop Materials, p. 5

Regular Capital Variances

On page 5 of the Workshop Materials, FortisBC provides an illustrative calculation to show how variances in capital spending will affect the achieved ROE:

Line	Particulars	Forecast	Actual	Difference	Reference
1	Capital Spending	$100,000	$ 95,000	(5,000)	
2	Mid-Year add to Rate Base	$ 50,000	$ 47,500		
3					
4	Depreciation Rate	3.0%	3.0%		No depreciation impact in first year
5	Depreciation Expense	3,000	2,850		however, included in this calculation
6					
7	Debt Ratio	60%	60%		
8	Interest Rate	5.5%	5.5%		
9	Interest Expense	1,650	1,568		Line 2 x Line 7 x Line 8
10					
11	Income Tax Rate	27.0%	27.0%		
12	Income Tax Expense	666	632		Complex calc, therefore estimate
13					
14	**Sum of Depreciation, Interest and Income Tax Expense**	**5,316**	**5,050**	**(266)**	*** Line 5 + Line 9 + Line 12**

* Lower actual expenses than forecast, shown in the Difference column, will result in an increase to the earnings and, correspondingly, an increase in the achieved ROE.

64.1 Please confirm, or explain otherwise, that FortisBC's proposed approach to forecasting sustainment/other capital and growth capital (for FBC) in this Application results in FortisBC recovering the forecast ROE impact attributable to capital fully from ratepayers but that the positive or negative ROE impact of the variance between forecast and actual costs incurred will be shared 50/50 with ratepayers.

Response:

Confirmed.

64.2 Please discuss how FEI and FBC might overcome the potential inherent bias to over forecast capital spending in this Application which would not exist to the same extent if the capital expenditures were flow-through or if the existing approach under the Current PBR Plan were utilized.

Response:

FortisBC does not agree with the premise that the Application contains a potential bias to over-forecast capital spending. The capital expenditures forecasts for the MRPs are bottom-up forecasts based on known requirements over the 2020-2024 period. The proposed cost of service approach is transparent and FortisBC's capital expenditures are reasonable and justifiable. FortisBC does not believe that there is any bias in its capital expenditure forecasts.

The formula approach to capital expenditure forecasts under the Current PBR Plans resulted in under-forecasting of capital and was not a reasonable basis on which to forecast future expenditures.

The proposed treatment of variances is designed to encourage FortisBC to manage its capital expenditures below the amounts embedded in rates. If capital expenditures were treated as flow-through, the Companies would have less incentive to pursue capital efficiencies as all benefits would immediately be returned to customers. Similarly, there would be no penalty to the Companies for over-spending as the revenue requirements impacts would be fully recovered by way of the flow-through mechanism.

Under the proposed mechanism, the Companies retain 50 percent of any benefits of efficiencies and are responsible for 50 percent of any overspending for the MRP period. Amending the ratio to 75/25 for the ratepayer/utilities would reduce the incentive for FortisBC to manage its capital expenditures below the amounts embedded in rates. FortisBC would retain fewer benefits when spending was lower than those embedded in rates and would incur less risk when costs were above those embedded in rates.

FortisBC notes that, on page 33 line 26 to page 34 line 16 of Transcript Volume 1, from the Workshop on May 1, 2019, FortisBC mistakenly indicated that there would be a true-up for actual capital expenditures within the term of the MRP. To clarify, FortisBC is not proposing a true-up of rate base for actual regular capital spending over the term of the MRP.[53] The approved forecast of capital will be embedded in rates over the term of the MRP with no adjustment for actuals until after the end of the term.

64.2.1 As part of the above response, please discuss the appropriateness, including the pros and cons, of the following three alternative approaches: (i) treating variances in all capital spending as flow-through; (ii) increasing the ESM percentage for ratepayers, such as

[53] Except FEI has proposed an adjustment for actual gross customer additions for growth capital.

75% to ratepayers and 25% to the utilities; and (iii) no true up for actual capital spending compared to forecast during the MRP term.

Response:

Please refer to the response to BCUC IR 1.64.2.

65.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.4.2, pp. C-110 – C-113

Investments in a Clean Growth Future

On page C-110 and in Section 4.4.2 of the Application, FortisBC proposes provide an annual forecast of O&M and cost of service related to capital expenditures for investments in a clean growth future and for these costs to be afforded flow-through deferral account treatment.

FortisBC states on page C-111 of the Application: "This category currently consists of NGT fuelling stations and tankers, variable LNG production, RNG and EV charging stations. However, FortisBC may propose to add other initiatives to this category over the term of the Proposed MRPs."

65.1 Please explain and discuss the factors or criteria which FortisBC will consider in order to determine what other initiatives should be "added to this category" in the future.

Response:

FortisBC stated on page C-110 of the Application that this category would include "other initiatives in alignment with government policy" and, in particular for this category, this is intended to refer to initiatives that support the achievement of policy related to a clean growth future. The policy would be the driver for a new initiative, and the materiality of such an initiative will be a consideration in whether it should be added to this category, in the interest of regulatory efficiency. An example might be the development of a hydrogen injection project to support the achievement of both emissions reduction and renewable gas targets set by government.

65.1.1 Please confirm, or explain otherwise, that FortisBC will seek BCUC approval of additional initiatives if/when they occur.

Response:

Confirmed.

66.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.7, p. C-114; Exhibit B-2, Appendix A

Other Revenue

On page C-114 of the Application, FortisBC states: "Components of other revenue that currently have deferral account treatment are FEI's Southern Crossing Pipeline [SCP] Third Party Revenue, CNG & LNG Service Revenue and RNG Other Revenue. FortisBC proposes to continue this treatment."

FortisBC further states on page C-114 of the Application that it 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."

The above proposals are summarized in Appendix A of Exhibit B-2 in the following excerpts:

Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	SCP Revenues deferral
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	CNG/LNG Recoveries deferral
Revenues from Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Flow-through deferral	**Subject to earnings sharing**

	Current Treatment (2014-2019 PBR Plan)	Proposed Treatment (2020-2024 MRP, Table C4-1, Page C-118)
	FBC	FBC
Other Revenues :		
SCP Mitigation revenues variances	N/A	N/A
CNG/LNG Recoveries variances	N/A	N/A
Revenues from Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Flow-through deferral	**Subject to earnings sharing**

66.1 Please reconcile the statement on page C-114 of the Application that "the risk of variances in other components of this other revenue item will be to the account of the shareholder" with the statement in Appendix A to the Workshop Materials which states that all other revenue/income variances will be subject to earnings sharing under the proposed MRP.

Response:

Describing variances that are "a risk to the shareholder" or "subject to earnings sharing" are equivalent terms. Variances that are "a risk to the shareholder" fall to the bottom line (earnings) and are "subject to earnings sharing".

Other Revenue includes a number of components. Under the Current PBR Plans, all of these Other Revenue components have flow-through treatment either through specific deferral accounts as described on page C-114 of the Application or through the Flow-through deferral account approved in the Current PBR Plans. The Companies propose to change the treatment of variances of some of the Other Revenue components so that variances are not captured in the Flow-through deferral account but rather fall to earnings and are subject to earnings sharing. The following list is an expansion of Table C4-1 in the Application, which shows all of the Other

Revenue components, the existing treatment under the Current PBR Plans and the proposed treatment in the Application.

	Current Treatment FEI	**Proposed Treatment** FEI
SCP Mitigation Revenues variances	SCP Revenues deferral	SCP Revenues deferral
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	CNG/LNG Recoveries deferral
Revenues from Clean Growth Projects[1,2]	Flow-through deferral	Flow-through deferral
All other other revenue/income components		
Late Payment Charge	Flow-through deferral	Subject to earnings sharing
Connection Charge	Flow-through deferral	Subject to earnings sharing
NSF Returned Cheque Charges	Flow-through deferral	Subject to earnings sharing
Other Recoveries	Flow-through deferral	Subject to earnings sharing
NGT Overhead and Marketing Recovery	Flow-through deferral	Subject to earnings sharing
LNG Mitigation Revenue	no variance	no variance

	Current Treatment FBC	**Proposed Treatment** FBC
Revenues from Clean Growth Projects[1]	Flow-through deferral	Flow-through deferral
All other other revenue/income components		
Late Payment Charge	Flow-through deferral	Subject to earnings sharing
Connection Charge	Flow-through deferral	Subject to earnings sharing
Other Recoveries	Flow-through deferral	Subject to earnings sharing
Apparatus and Facilities Rental	Flow-through deferral	Subject to earnings sharing
Contract Revenues	Flow-through deferral	Subject to earnings sharing
Transmission Access Revenue	Flow-through deferral	Subject to earnings sharing
Interest Income	Flow-through deferral	Subject to earnings sharing

Notes

1: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.

2: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

66.2 Please provide in a table format a list and description of "all other revenue/income variances" which are included in the proposal above for each of FEI and FBC.

Response:

Please refer to the response to BCUC IR 1.66.1.

67.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.8, pp. C-114 – C-115, C-118

Interest Expense

On page C-115 of the Application, FortisBC states the following:

> 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. [*Emphasis added*]

The proposal is summarized in Table C4-1 of the Application in the following excerpt:

Table C4-1: Treatment of Variances in Revenue Requirement Items from Forecast

	FEI	FBC
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

67.1 Please explain why FortisBC's proposals with respect to variances in interest expense are different with respect to short-term and long-term debt.

Response:

FortisBC's proposals are the same as what has previously been approved for FEI in years prior to 2014 and for FBC in its 1996-2004 PBR Plan. That is:

1. Variances in uncontrollable components – interest rates, and timing and amount of debt issues that result from external capital market and economic factors – are captured in the Flow-through deferral account and flowed through to customers; and

2. Variances in short-term interest, which are primarily driven by variances in regular capital expenditures, affect earnings and the earnings sharing calculation. This is because, once the long term debt is trued up to forecast, the amount of volume variance remaining falls to short-term debt, which is used to fund capital expenditures in any given year.

67.2 Please clarify what "Other interest variances" are as shown in Table C4-1 of the Application and whether they relate to short-term debt or long-term debt, or both.

Response:

Please refer to the response to BCUC IR 1.67.1.

67.3 Please explain and provide a numerical example of how variances in interest expense related to short-term debt and long-term debt will be treated during the proposed MRP term, including the impact on the annual ROE and the proposed 50/50 ESM.

Response:

There are no variances in existing long-term debt interest expense as these issuances are historical and at fixed rates. Any variances in long-term debt interest expense stem from the forecast issuances in the rate setting year. All long-term debt interest variances and variances in interest rates for short-term debt will be accounted for in the Flow-through deferral account. Variances in interest caused by the volume of short-term debt, except for volume of short-term debt caused by long-term debt issue volume and timing, will fall to earnings and be subject to earnings sharing. FortisBC has provided the following calculations to demonstrate how variances in long-term and short-term debt interest expense will be accounted for through the term of the MRPs.

All dollars in ($000)

Line	Forecast						Actual				
1											
2	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
3	Mid Year Rate Base		**5,000,000**				Mid Year Rate Base		**5,100,000**		
4				**Interest Rate**	**Interest Expense**					**Interest Rate**	**Interest Expense**
5	Equity	38.5%	1,925,000				Equity	38.5%	1,963,500		
6	LTD	57.0%	2,850,000	4.98%	142,000		LTD	56.8%	2,897,500	4.98%	144,388
7	STD	4.5%	225,000	3.00%	6,750		STD	4.7%	239,000	2.50%	5,975
8	Total	100.0%	**5,000,000**		**148,750**		Total	100.0%	**5,100,000**		**150,363**

Forecast

Month					
7	**Rate**	5.00%	4.00%	3.00%	
	LTD Issue		100,000		

		Existing LTD	LTD Issue	STD	Total Debt	LTD Interest	STD Interest	Total Interest
1	Jan	2,800,000	-	275,000	3,075,000	11,667	688	12,354
2	Feb	2,800,000	-	275,000	3,075,000	11,667	688	12,354
3	Mar	2,800,000	-	275,000	3,075,000	11,667	688	12,354
4	Apr	2,800,000	-	275,000	3,075,000	11,667	688	12,354
5	May	2,800,000	-	275,000	3,075,000	11,667	688	12,354
6	Jun	2,800,000	-	275,000	3,075,000	11,667	688	12,354
7	Jul	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
8	Aug	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
9	Sep	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
10	Oct	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
11	Nov	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
12	Dec	2,800,000	100,000	175,000	3,075,000	12,000	438	12,438
	Average	**2,800,000**	**50,000**	**225,000**	**3,075,000**			
	Total					**142,000**	**6,750**	**148,750**

Actual

Month					
4	**Rate**	5.00%	4.50%	2.50%	
	LTD Issue		130,000		

		Existing LTD	LTD Issue	STD	Total Debt	LTD Interest	STD Interest	Total Interest
1	Jan	2,800,000	-	336,500	3,136,500	11,667	701	12,368
2	Feb	2,800,000	-	336,500	3,136,500	11,667	701	12,368
3	Mar	2,800,000	-	336,500	3,136,500	11,667	701	12,368
4	Apr	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
5	May	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
6	Jun	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
7	Jul	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
8	Aug	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
9	Sep	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
10	Oct	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
11	Nov	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
12	Dec	2,800,000	130,000	206,500	3,136,500	12,154	430	12,584
	Average	**2,800,000**	**97,500**	**239,000**	**3,136,500**			
	Total					**144,388**	**5,975**	**150,363**

48	**Long Term Debt Variance**	**2,388**	Line 46, Column (g) - Line 27, Column (g)
49	**Short Term Debt Variance**	**(775)**	Line 46, Column (h) - Line 27, Column (h)
50	Total Interest Variance	1,613	Line 48 + line 49

1

51			
52	*STD Rate Variance*		
53	Actual ST Debt Rate	2.50%	Line 30, Column (e)
54	Forecast ST Debt Rate	3.00%	Line 11, Column (e)
55	Difference	-0.50%	Line 53 - Line 54
56	Forecast Average ST Debt Volume	225,000	Line 26, Column (e)
57	ST Debt Rate Variance	(1,125)	Line 55 x Line 56
58			
59	*STD Volume Variance from LTD Issue*		
60	Actual LT Debt Issue Volume	130,000	Line 31, Column (d)
61	Forecast LT Debt Issue Volume	100,000	Line 12, Column (d)
62	Difference	30,000	Line 60 - Line 61
63	Actual ST Debt Rate	2.50%	Line 30, Column (e)
64	Forecast LT Debt Issue Month	7	Line 12, Column (a)
65	STD Volume Variance from LTD Issue	(375)	Line 62 x line 63 / 12 x (Line 64 - 12 -1)
66			
67	*STD Timing Variance from LTD Issue Timing*		
68	Actual LT Debt Issue Month	4	Line 31, Column (a)
69	Forecast LT Debt Issue Month	7	Line 12, Column (a)
70	Difference	(3)	Line 68 - Line 69
71	Actual LT Debt Issue Volume	$ 130,000	Line 31, Column (d)
72	Actual ST Debt Rate	2.50%	Line 30, Column (e)
73	STD Timing Variance from LTD Issue Timing	$ (813)	Line 70 x line 71 x Line 72 / 12
74			
75	*STD Volume Variance from Actual Rate Base*		
76	Actual ST Debt Average Volume	239,000	Line 45, Column (e)
77	Forecast ST Debt Average Volume	225,000	Line 26, Column (e)
78	Difference	14,000	Line 76 - Line 77
79	Actual ST Debt Rate	2.50%	Line 30, Column (e)
80	Product	350	Line 78 x Line 79
81	STD Timing Variance from LTD Issue Timing	(813)	Line 73
82	STD Volume Variance from LTD Issue	(375)	Line 65
83	STD Volume Variance from Actual Rate Base	1,538	Line 80 - Line 81 - Line 82
84			
85	**Total STD Variance**	**(775)**	Line 57 + Line 65 + Line 73 + Line 83
86			
87	**Captured in Flow-Through Deferral**	**75**	Line 48 + Line 57 + Line 65 + Line 73
88	**To Earnings and Subject to Sharing**	**1,538**	Line 83
89	Total	1,613	Line 87 + Line 88

As a proof, the amount of earnings subject to sharing (Line 88 in the table above) could also be calculated as the $100,000 change in rate base ($5,100,000 - $5,000,000) x 61.50% debt proportion of rate base x 2.50% actual ST debt rate = $1.538 million.

68.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.13, p. C-117

Summary of Proposed Revenue Requirement Treatment

On page C-117 of the Application, FortisBC states the following:

> 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. [*Emphasis added*]

68.1 Please clarify the above statement that "these variances will accrue to the shareholder" in consideration of FortisBC's proposed ESM. As part of this response, please explain how the above-noted variances are treated in the Current PBR Plans, and discuss the impact from a ratepayer and shareholder perspective of the proposed changes.

Response:

The variances described as accruing to the shareholder will be subject to the ESM and shared 50/50 between the shareholder and customers. In the Current PBR Plans, the above-noted variances (namely depreciation, interest and income taxes) are accounted for in the Flow-through Deferral Account and accrue to customers. Under the proposed approach the shareholder is taking more risk on overspending and retains more reward for controlling spending. This feature creates a greater incentive for the Companies to manage capital spending which will yield benefits to customers for the long term over the lives of the assets.

69.0 Reference: ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section 4.10, p. C-116; FEI PBR Decision, p. 98; FBC PBR Decision, p. 95

Exogenous Factors

On page C-116 of the Application, FortisBC states the following:

> Consistent with its position in the 2014 PBR proceedings, FortisBC believes that a materiality threshold is neither required no[r] 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.

On page 98 of the FEI PBR Decision and page 95 of the FBC PBR Decision, the BCUC stated the following:

> The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time. Establishing a materiality threshold also reduces the reliance on Fortis' judgement and instead creates a more transparent and objective process for determination of exogenous factor applicability.

69.1 Please compare the inclusion of a materiality threshold versus the exclusion of a materiality threshold on the following: (i) impact on the regulatory burden; (ii) reliance on FortisBC's judgement for bringing forward an exogenous factor proposal; and (iii) the transparency and objectiveness of the review process for determining exogenous factor applicability.

Response:

(i) Impact on the regulatory burden:

FortisBC believes that the exclusion of a materiality threshold will not result in increased regulatory burden. The Companies recognize the importance of the regulatory efficiency objectives in making their requests and do not intend to bring forward minor items that would otherwise meet Z-Factor related criteria. Further, there was confusion in the Current PBR Plans on how to measure the materiality threshold (annual, cumulative, O&M and

capital, together or separate) that took away from any perceived regulatory efficiency from a set materiality threshold.

(ii) Reliance on FortisBC's judgement for bringing forward an exogenous factor proposal:

The process for considering exogenous factors has been well established through the Annual Reviews during the Current PBR Plans. The process relies on FortisBC's judgement to bring forward exogenous factor proposals whether or not there is a materiality threshold. In either case, FortisBC has the burden of proof for demonstrating that costs or savings meet the exogenous factor criteria and the BCUC has the opportunity to consider the appropriate treatment of such items. As noted above, the Companies recognize the importance of the regulatory efficiency objectives of the MRPs and do not intend to bring forward minor items that would otherwise meet Z-Factor related criteria.

(iii) Transparency and objectiveness of the review process for determining exogenous factor applicability:

The process for considering exogenous factors will remain the same as under the Current PBR Plans, allowing a transparent and objective review of proposed exogenous costs. FortisBC will bring forward in its Annual Reviews cost pressures or savings that it believes should be treated as exogenous factors. Interveners and the BCUC will be able to pose questions relating to the nature of the items and the applicability of exogenous factor criteria. Interveners will be able to make arguments for or against the proposed treatment, and the BCUC will make a final determination. In this way, the BCUC's objectives for a transparent and objective process for the determination of exogenous factor applicability will continue to be achieved.

69.1.1 In consideration of the above factors, please provide an assessment of the exogenous factor review process under the Current PBR Plans and whether, in FortisBC's view, the BCUC's stated objectives of the materiality threshold in the PBR Decisions (as provided in the above preamble), were achieved.

Response:

Please refer to the response to BCUC IR 1.69.1.

69.2 If the proposed removal of the materiality threshold were approved, what is the likelihood that an increased number of exogenous factors would be brought forward by FortisBC during the proposed MRP term? Please discuss.

Response:

The Companies recognize and will consider the importance of regulatory efficiency objectives in making their requests and, therefore, do not intend to propose minor items for exogenous factor treatment. However, it is not possible to estimate the number of future exogenous factor requests, as exogenous factor treatment is only for non-controllable and unforeseeable items. FortisBC anticipates that removing the exogenous factor materiality threshold will reduce confusion and the complexity of legal argument regarding the application of the materiality threshold, as was experienced during the Current PBR Plans.

69.2.1 As part of the above response, please discuss the potential impact that an increase in exogenous factor requests may have on the annual review process, and whether it may negatively impact FortisBC's goal of an "administratively more simple and more efficient" process.

Response:

FEI believes that removing the materiality threshold will make the Annual Review process administratively simpler and more efficient. The impact of an increased number of exogenous factors, if any, would be outweighed by the efficiencies achieved by not having to argue and present evidence about the application of the materiality threshold. Please also refer to the response to BCUC IR 1.69.2.

69.2.2 If FortisBC does not consider that the removal of the materiality threshold would result in an increase in the number of exogenous factors to be reviewed during the proposed MRP term, please explain why.

Response:

Please refer to the responses to BCUC IRs 1.69.2 and 1.69.2.1

F. DEFFERAL ACCOUNTS

70.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-1, Section C5.3.2.2, 6.6, pp. C-120, C-122 – C-126, C-139, C-145 – C-146; Workshop Transcript, pp. 43, 47 – 49, 51

Innovation Funding Account

On page C-120 of the Application, FortisBC states: "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."

The proposed rate riders are calculated in Table C6-3 on page C-146 of the Application, as follows, based on annual funding of $4.9 million for FEI and $0.5 million for FBC:

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

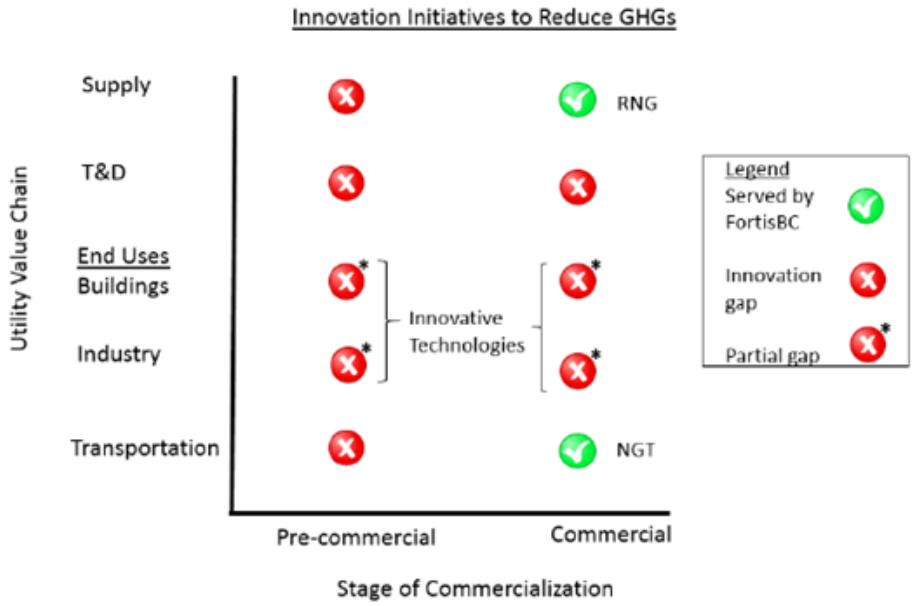
On page C-146 of the Application, FortisBC states: "Recognizing that the Companies will only need half of the annual funding in 2020 as activities ramp up, the riders will not be implemented until July 1, 2020."

FortisBC stated during the Workshop that it "totaled up" the funding requests it has received in various innovation activities over the next couple of years to determine the level of funding.[54] FortisBC also stated "where it exists" that it will be pursing Government funding for R&D and demonstration activities.[55]

On page C-139 of the Application, FortisBC provides the following figure:

[54] T1: pp. 48-49.
[55] T1: pp. 50-51.

Figure C6-4: Innovation Gaps to be Addressed by the Fund



70.1 With reference to the innovation gaps (and partial gaps) identified in Figure C6-4 of the Application, please provide a breakdown and description of the initiatives for which FortisBC intends to utilize the annual $4.9 million (FEI) and $0.5 million (FBC) on during the proposed MRP term to address the identified "gaps".

Response:

In determining the funding requirements for the Clean Growth Innovation Fund, FortisBC used a bottom-up approach identifying the research and development activities that are expected to be funded in 2020 by each segment, shown in Table C6-2 of the Application. Expenditure levels and activity types will vary from year to year. Therefore, FortisBC is not able to identify forecast expenditures by segment beyond 2020. However, the figures for 2020 are shown in the table below.

Segment	FEI ($ millions)	FBC ($ millions)
Supply	1.5	
T&D	0.5	
End-Use: Buildings	1.0	0.1
End-Use: Industry	0.5	
Transportation	1.5	0.4
Total	**$5.0**	**$0.5**

Please also refer to Appendix C6-4, Main Innovation Activities, which describes the Innovations Fund's main innovation activities that FortisBC intends to pursue, including the likely technology readiness levels.

70.1.1 Please confirm, or explain otherwise, that the amounts provided above are net of any funding from either the Provincial or Federal Governments.

Response:

Confirmed.

During the Workshop, FortisBC stated that the proposed innovation funding account rate riders are expected to remain constant throughout the proposed MRP term.[56]

70.2 Given that the proposed Clean Growth Innovation Fund (Innovation Fund) deferral account rate riders are expected to remain constant over the term of the proposed MRPs, please confirm, or explain otherwise, that the total amount of funding collected from customers will be impacted by the actual number of customers of FEI and FBC, respectively, over the term of the proposed MRPs.

Response:

Confirmed.

70.2.1 If confirmed, please provide FortisBC's calculations of the anticipated funding levels for annual innovation activities for each year of the proposed MRP term based on the forecast average number of

[56] T1: p. 49.

customers in those years (i.e. assuming the $0.40 and $0.30 riders for FEI and FBC, respectively, are held constant).

Response:

FortisBC has not produced a forecast of customers over the term of the MRPs; however, assuming FEI and FBC add approximately 10,000 and 2,000 customers per year respectively, the approximate total funding by year is included in the table below.

$ millions	2020	2021	2022	2023	2024
FBC	0.5	0.5	0.5	0.5	0.5
FEI	4.9	5.0	5.0	5.1	5.1

70.2.2 Under what circumstances, if any, would FortisBC apply for changes to the Innovation Fund deferral account rate riders and what would be FortisBC's proposed process (e.g. as part of the Annual Reviews or other regulatory process)?

Response:

FortisBC has not determined under what circumstances, if any, it would apply for changes in the Clean Growth Innovation Fund deferral account riders. However, if FortisBC decided to apply for a change in the riders, the Companies would likely do so within the Annual Review process, along with changes to other rate riders that are normally requested.

70.3 To the extent possible, please provide the incremental percentage impact on rates that the proposed Innovation Fund rate riders are expected to have on FEI and FBC customers over the term of the proposed MRPs.

Response:

The one-time incremental percentage rate impacts of the proposed Clean Growth Innovation Fund rate riders are approximately 0.5 percent for FEI and 0.25 percent for FBC.

70.3.1 Please discuss whether there is a maximum incremental percentage impact on rates which FortisBC considers appropriate when determining the amount of the rate riders.

Response:

FEI considers the impact of rate riders within the context of overall rate impacts. Although there is no specific maximum rate impact, other than the avoidance of rate shock which is generally considered to be a bill impact of 10 percent or greater, FortisBC works to manage rate impacts if it has flexibility to do so.

As shown in the response to BCUC IR 1.70.3, the Clean Growth Innovation Fund by itself does not result in excessive rate impacts. Further, as indicated on pages C-173 and C-174 of the Application, when including the impact of the rate rider implementation in 2020, overall rate impacts are expected to be reasonable, and can be further managed by the existing revenue surpluses.

FortisBC states the following on page C-120 of the Application:

> 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.

70.4 Please provide examples, if any, of other Canadian and other US jurisdictions in which a regulated utility has used a similar rate rider/charge and deferral account to the proposed Innovation Fund deferral account.

Response:

Appendix C6-1 of the Application identifies a number of North American utilities that have customer funded innovation programs. The funding levels are included in Appendix C6-1 and a summary table from page 5 of Appendix C6-1 is included below.

The funding mechanisms are varied. Some include a separate charge on the bill that may cover multiple categories, including innovation (NY collects NYSERDA funds, among other things, through the System Benefits Charge). Other utilities roll innovation funding into other, more general rates and charges (Minnesota), and some add innovation funding to the company's revenue requirement (Australia or UK).

Regardless of whether the funding occurs through embedding an amount in the revenue requirement or through a per customer charge (by way of a rate rider), both mechanisms collect the funds during the year in which the funds are utilized. Even though, for FortisBC, the proposed rate rider will not appear separately on each customer's bill (it will be bundled together with the basic charge), the proposed approach allows FortisBC to charge each customer the same amount, whereas if it was embedded in the revenue requirement customers would be charged differently based on their volume.

FortisBC believes that its proposed mechanism is best aligned with the intended beneficiaries of the fund, namely, all customers.

Table ES-1: Summary of Innovation Programs

Regulator/ Government	Program/ Directive	Link to Program	Start Date	Funding Level (annually per customer, $USD)
Ofgem	RIIO framework: Network Innovation Allowance (NIA) & Network Innovation Competition (NIC)	https://www.ofgem.gov.uk/network-regulation-riio-model https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation	2013-2015*	NIA: $1.13 NIC: $4.11 Electricity, $1.23 Gas
California PUC	California Energy Systems for the 21st Century (CES-21)	https://www.llnl.gov/sites/default/files/field/file/CES21.pdf	December 2012	$0.87
California PUC	Electric Program Investment Charge (EPIC)	http://www.energy.ca.gov/research/epic/	May 2012	$13.61
New York PSC and NYSERDA	Reforming the Energy Vision (REV)	https://rev.ny.gov/ http://www.dps.ny.gov/REV/	April 2014	NYSERDA funding: $4.69 ConEd REV project: $9.33
Minnesota PUC	Renewable Development Fund	https://www.xcelenergy.com/energy_portfolio/renewable_energy/renewable_development_fund	1994	$9.12
Australian Energy Regulator	Demand management incentive scheme and innovation allowance mechanism	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism	December 2017	DMIA: $0.72 *(hypothetical)*
Massachusetts DPU	Order requiring Grid Modernization Plan	http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf	June 2014	Eversource demo projects: $14.12
IESO (Ontario)	Conservation Fund	http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview	2005	*Insufficient data*

*Start dates vary by gas vs. electricity, and transmission vs. distribution.

70.4.1 For each regulated entity identified, please provide a detailed description and comparison of the entities' fund and funding mechanism to the proposed Innovation Fund and rate riders.

Response:

Please refer to the response to BCUC IR 1.70.4.

70.5 Please clarify whether the commitment by FEI and FBC is to not spend more than what is collected on: (i) an annual basis (i.e. $2.45 million in 2020 and $4.9 million in each of 2021-2024 for FEI, and $0.25 million in 2020 and $0.5 million in each of 2021-2024 for FBC); or (ii) in aggregate over the term of the proposed MRPs (i.e. $22.05 million for FEI and $2.25 million for FBC from 2020-2024).

Response:

The commitment by FortisBC is to not spend more than the aggregate amount collect over the term of the MRPs.

On page C-124 of the Application, ForticBC states: "FEI/FBC are seeking to recover the costs, via rate rider, in the same year the costs are incurred, which service to match the costs and benefits. See Section C5.3.2.2. There are no intergenerational inequities inherent in this practice."

On page C-128 of the Application, FortisBC states the following:

> …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.

70.6 Please explain why intergenerational inequities are not inherent given that the clean energy innovation activities are meant to benefit the future (e.g. cost reductions, reduced emissions and lower carbon economy).

Response:

The timeline on which benefits from the Clean Growth Innovation Fund will be realized will depend upon whether the investment is for commercial activities or for pre-commercial activities as shown in Figure C6-4 of the Application. Commercial innovations will see benefits realized sooner while pre-commercial benefits will take longer to realize. Within the pre-commercial

category, the realization of benefits will also depend on the Technology Readiness Level (TRL) as shown in Figure C6-6 of the Application. Higher numeric TRL level initiatives will, on average, realize benefits sooner than those with lower numeric values.

Customers, and British Columbians in general, should benefit quickly from commercial innovations such as increased use of natural gas for transportation and electric fleet vehicles. These innovations have the immediate potential to reduce the cost of transportation and lower overall emissions.

Notwithstanding the fact that customers should benefit quickly from commercial innovations, the concept of intergenerational equity carries with it a matter of degree,. In this case, FortisBC does not believe the proposed Clean Growth Innovation Fund raises material concerns about intergenerational inequity, because even though some of the benefits may be more future oriented, they are being undertaken in an effort to ensure that FortisBC's existing customers will continue to be customers for the long term.

G. FORTISBC CLEAN GROWTH INNOVATION FUND

71.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C2.4, p. C-22; Workshop Transcript, pp. 41, 46–47; Exhibit A2-1

FortisBC Innovation Activities

During the Workshop, FortisBC stated the following:

> We've been innovating for many years. Many of you are aware that we were one of the first companies to offer renewable natural gas in North America. We have been innovators in natural gas for transportation in heavy duty vehicles and marine.[57]
>
> …
>
> …I didn't mention that in the list of partnerships that we'll be looking for these, but absolutely we will be working with other utilities. And in fact the natural gas innovation fund, for example, that we're a part of now is a collection of natural gas utilities across Canada that are all interested, in many cases in the same type of fund, and investing in the same type of technologies. So, absolutely where we have a common interest we'll be partnering.[58] [*Emphasis added*]

In Exhibit A2-1, BCUC staff provides a document titled "Natural Gas Innovation Fund Launches $1.5 Million Cleantech Competition" which states, among other things the following:

> Today [May 9, 2019] the Natural Gas Innovation Fund (NGIF) announced a $1.5 million funding call to advance cleantech solutions in three strategic focus areas – energy efficiency; renewable gases (including renewable natural gas and hydrogen); and carbon capture – for natural gas distribution and end use industry in Canada.
>
> NGIF is accepting submissions to its intake stage for funding requests to support new technologies and innovative approaches in the above three identified focus areas. We will make up to $300,000 in non-dilutive funding available per project in Canada, representing as much as 33 per cent of a project's eligible expenses. The competition is open for small to medium enterprises and technology development start-ups in Canada and globally.

[57] T1: p. 41.
[58] T1: pp. 46–47.

…

NGIF, created by the Canadian Gas Association (CGA), supports the funding of cleantech innovation in the natural gas value chain…

…NGIF's distribution investors include ATCO Gas Ltd., Enbridge Gas Inc., FortisBC Energy Inc., Pacific Norther Gas Ltd., and SaskEnergy.

On page C-22 of the Application, FortisBC states the following:

FortisBC is proposing the creation on an Innovation Fund...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.

71.1 Please explain if the NGIF described on page C-22 of the Application and the NGIF described in the article attached as Exhibit A2-1 are the same fund.

Response:

FortisBC confirms that the two NGIF references refer to the same fund.

71.1.1 If yes, please clarify if the $0.400 million in O&M incurred by FEI in 2018 is FEI's "contribution" to the NGIF created by the CGA. As part of this response, please explain if FEI intends to contribute to the CGA's NGIF annually and if so, what the annual contribution is estimated to be and whether (and how) this contribution is proposed to be recovered from ratepayers.

Response:

FEI confirms that the $0.400 million in O&M incurred by FEI in 2018 is its contribution to the NGIF. FEI intends to contribute annually to the NGIF regardless of approval of the Clean Growth Innovation Fund. However, in absence of approval of the Clean Growth Innovation fund, FEI is likely to limit its contribution to a maximum of $0.400 million, funded annually through its Base O&M.

71.2 Please explain in detail FEI's involvement with the NGIF described in Exhibit A2-1, including whether FEI plays a role in determining who the funding is awarded to and for what projects (and if so, what is FEI's level of involvement in this role).

Response:

The NGIF was created by the Canadian Gas Association (CGA). FEI is a founding member of NGIF along with ATCO Gas, Enbridge Gas, Energir, Pacific Northern Gas, and SaskEnergy. FEI has a governance role as a member of the Investment Committee, and is a member of the Evaluation Committee. These committees are comprised of other NGIF members.

As a member of the Evaluation Committee, FEI reviews and evaluates proponents who have applied to the NGIF for funding. Representatives from FEI participate in evaluations of potential investments, including on-site visits and scoring sheet assessments. Scoring sheet assessments are based on such factors as:

- Relevance and impact to natural gas customers;
- Management team;
- Project work plans; and
- Project budget.

After projects and funding levels are approved by the Evaluation Committee, the Investment Committee makes the final funding decisions. FEI only funds projects that have passed the Investment Committee stage and which FEI has an interest in funding; however, there is no obligation on FEI to fund specific projects. For example, more than one utility, including FEI, may be interested in funding a gas heat pump project. In that case, the funding is split amongst the participating utilities including FEI. In another instance, there are proponents that are seeking funding for a project that FEI does not have interest in and, accordingly, FEI does not have to invest in these projects. FEI does not bear any project funding obligation even though it sits on both committees and approved the projects.

71.3 Based on FortisBC's understanding of the NGIF described in the article provided as Exhibit A2-1, please provide the following information: the goals and objectives of the NGIF, the types of projects eligible for funding, the criteria for eligibility to be granted funds from the NGIF, and the annual funding available.

Response:

The NGIF website describes the goals and objectives of the NGIF as follows:[59]

> The Natural Gas Innovation Fund™ (NGIF) was created by the Canadian Gas Association (CGA) to support the funding of cleantech innovation in the natural gas value chain. It seeks to fill a technology development gap in the sector and invests in innovation enabling natural gas solutions for current and emerging challenges facing Canada's energy system.
>
> We are funded by the natural gas industry. With access to pooled capital, leveraged intelligence and a combined backyard across Canada to field test innovation, the natural gas industry can select and advance cleantech projects led by startups and organizations with the right innovation for market uptake and commercial viability.

The type of projects eligible for funding may vary from one round to another within the mandate described above. As referenced in the preamble, the current round of funding is for "three strategic focus areas – energy efficiency; renewable gases (including renewable natural gas and hydrogen); and carbon capture – for natural gas distribution and end use industry in Canada."

Funding is not granted on an annual basis, but on a project basis as identified in the question preamble:

> [NGIF] will make up to $300,000 in non-dilutive funding available per project in Canada, representing as much as 33 per cent of a project's eligible expenses. The competition is open for small to medium enterprises and technology development start-ups in Canada and globally.

FEI lists the evaluation criteria categories in its response to BCUC IR 1.71.2.

71.4 Please explain how the NGIF created by the CGA is expected to directly benefit FEI and its ratepayers.

[59] http://www.ngif.ca/about/.

Response:

One of the stated goals of the NGIF is to accelerate clean technology innovation, which is also one of the goals of the Clean Growth Innovation Fund. FortisBC expects this acceleration to directly benefit FEI ratepayers by achieving performance breakthroughs and cost reductions and supporting the transition to a lower carbon economy.

71.5 With regard to FortisBC's statements at the Workshop that it is now part of a "collection of natural gas utilities across Canada," please provide a list of these utilities which FortisBC is partnering with and if this statement is related to the NGIF created by the CGA.

Response:

The statement was related to the NGIF created by the CGA. The NGIF's natural gas distribution investors include ATCO Gas, Enbridge Gas, FortisBC Energy, Pacific Northern Gas., and SaskEnergy.

71.5.1 Please clarify if any of the entities FortisBC is partnering with are electric utilities and if not, why not. As part of this response, please specifically discuss FBC's role in the existing partnerships.

Response:

The NGIF was formed by the Canadian Gas Association to fill a technology gap in natural gas innovation. It was not, and is not, intended to address electricity innovation.

Atco Gas' parent company has electrical generating assets. Similarly, SaskEnergy is a crown corporation of the Province of Saskatchewan who also owns the electric distribution system. The other NGIF member utilities listed in the response to BCUC IR 1.71.5 are not electric utilities to the best of FortisBC's knowledge. FBC, as an electrical utility, has no role in the existing partnerships.

71.5.2 Other than the entities identified in the above IR, what other entities would FortisBC consider partnering with in its innovation activities? Please discuss.

Response:

Entities that FortisBC would consider partnering with in addition to the NGIF would include:

- Other utilities;
- Academic institutions;
- Businesses;
- Industry associations;
- Governments; and
- Non-government organizations.

71.5.3 Please describe the financial arrangements that FortisBC has with the entities it is partnering, including how contributions are determined, by whom, and who administers the contributions.

Response:

FEI's funding arrangement related to the NGIF is described in the response to BCUC IR 1.26.6.

72.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.1, p. C-128; Exhibit B-1-1, Appendix A5, pp. 3, 20

Funding of Clean Energy Innovation

On page C-128 of the Application, FortisBC states the following:

> …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…
>
> 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. [*Emphasis added*]

On page 3 of Appendix A5, FortisBC states: "This paper presents FortisBC's pathway to align with the provincial government's goal to significantly reduce greenhouse gas emissions while supporting economic growth and maintaining affordability and customer choice."

On page 20 of Appendix A5, FortisBC states the following:

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

72.1 Please confirm, or explain otherwise, that the "Clean Growth Pathway to 2050" report provided in Appendix A5 is FortisBC's submission to the Provincial Government's recent CleanBC public consultation process.

Response:

Confirmed.

72.2 Please provide further details on the Clean Industry Fund referenced on page 20 of Appendix A5. As part of this response, please explain if this is fund proposed by the Provincial Government or by FortisBC and who contributes to this fund (e.g. taxpayers, FortisBC, etc.).

Response:

The Clean Growth Industry Fund is now renamed to the CleanBC Industry Fund (CBCIF). The CBCIF is managed by the Climate Action Secretariat (CAS) and is funded by the provincial government. The CBCIF is a component of the CleanBC Program for Industry. Industrial facilities emitting over 10,000 tonnes of CO_2e are automatically included in the program. These facilities are eligible for the Industrial Incentive Program which rebates carbon tax payments above $30 per tonne to individual facilities provided they achieve a carbon intensity performance benchmark. Performance benchmarks are currently being determined by CAS in consultation with industry. The key criterion for determining the benchmark is that it meets or exceeds the performance of the best facilities in the world. Facilities in BC that meet or achieve the top performance benchmark will receive a full rebate of carbon taxes paid above $30 per tonne. For facilities that do not meet the performance benchmark they may receive a partial rebate. Monies collected from the carbon tax above $30 that are not rebated back to industry are added to the CBCIF.

The CBCIF is a funding pool open to all participants in the CleanBC Program for Industry. The fund is focused on achieving short-term direct GHG reductions in industry. The fund is open for a fixed annual funding call where proponents must first submit an expression of interest and then after pre-screening are requested to submit a request for proposal. The fund is focused on projects that achieve real GHG reductions and is not currently open for applications for demonstration or innovation projects. The fund can provide up to $2 million at 50 percent leverage for capital projects.

Evaluative criteria for determining project funding are described below and taken from the 2019 RFP:[60]

[60] https://www2.gov.bc.ca/gov/content/environment/climate-change/industry/cleanbc-program-for-industry/cleanbc-industry-fund.

Weighted Criteria	Weight	Minimum score
Cost and Emissions Reduced • Amount of funding requested per tonne of emissions reduced between 2019 and 2030. • The Proponent's methodologies for estimating emission reductions will be assessed based on approaches set out in section 3 and must meet minimum standards of acceptability.	**60**	**10**
Project Timing • Project completion and emission reduction timelines.	**10**	**2**
Project Risks and Business Case All elements must meet minimum requirements: • Identified appropriate project risks, with measures to mitigate or manage risks to acceptable levels. • Demonstration that Project is unlikely to proceed in absence of Provincial funding. • Financial situation of Proponent.	**15**	**8**
Complementary Benefits • Identification of environmental and economic benefits, Indigenous involvement, and promotion of innovation and advancing technology adoption that results from the project.	**15**	**N/A**
• **TOTAL**	**100**	**20**

Notably, the criteria emphasizes the real, measurable GHG reductions achieved for successful projects, the completion time of projects and minimal risks to project completion. These criteria are not compatible with a fund like FortisBC's Clean Growth Innovation Fund that is focused on developing and commercializing innovative technologies to reduce GHG emissions over a longer-term.

72.3 Please provide a detailed comparison of the proposed Innovation Fund versus the Clean Industry Fund described in Appendix A5.

Response:

The proposed Clean Growth Innovation Fund has a separate and distinct focus from the CleanBC Industry Fund (CBCIF). As described in the response to BCUC IR 1.72.2, the CBCIF

is focused on funding immediate GHG reductions from projects using existing technologies across all industries. The purpose of the Clean Growth Innovation Fund is to ensure there are opportunities for FortisBC to participate and thrive in an evolving climate policy context by fully utilizing its natural gas and electric delivery systems. The Clean Growth Innovation 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. The CBCIF is focused on executable projects with existing technologies that have high GHG reduction potential in the short-term. In this sense, the CBCIF and the Fund do not overlap and FortisBC is interested in using both funds to advance GHG reductions in its system while moderating costs to ratepayers.

72.4 Is FortisBC aware of any feedback which has been received regarding the Clean Industry Fund? Please discuss.

Response:

Please refer to Attachment 72.4 for a copy of feedback that FortisBC submitted on the CleanBC Program for Industry to the provincial Climate Action Secretariat. FortisBC does not know whether any other feedback has been received by the Climate Action Secretariat.

73.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Sections C4.4.2, C6, pp. C-111, C-137 – C-138; Workshop Transcript, p. 41

Innovation Funding and Alternatives

On page C-111 of the Application, FortisBC states the following:

> 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.

73.1 Please confirm, or explain otherwise, that the proposed treatment of initiatives described on page C-111 of the Application is not referring to initiatives/projects/programs undertaken and expenditures incurred related to the proposed Innovation Fund.

Response:

Confirmed.

On pages C-137 and C-138 of the Application, FortisBC describes FEI and FBC's current innovation activities, including FEI's Innovative Technologies program related to its DSM expenditures and the NGT and RNG programs undertaken through the Greenhouse Gas Reduction Regulation (GGRR).

73.2 Please identify all areas of the proposed MRP in which FEI and FBC anticipate incurring expenditures (O&M and capital) on innovation projects, activities and initiatives. For each area of the MRP identified (e.g. formula O&M, forecast O&M, Innovation Fund, DSM deferral account, etc.), please provide a detailed description of how the expenditures are expected to be utilized and in what innovation areas.

Response:

While FortisBC does not generally categorize expenditures as "innovation projects, activities or initiatives", it has proposed the Clean Growth Innovation Fund for innovation expenditures as part of the MRPs. FortisBC has proposed to include the $0.400 million for the NGIF under the

Innovation Fund if approved. Expenditures within the DSM Innovative Technologies program are outside of the MRPs and approved through separate processes. Please refer to the response to BCUC IR 1.73.7 for further details on this program including historical and approved expenditures during the MRP period. Finally, expenditures under the GGRR are prescribed undertakings that fall outside of the MRPs and also support commercial activities. Further details on expenditures under the GGRR are addressed in the response to BCUC IR 1.73.11.

73.3 Please identify all areas within the Current PBR Plan in which FEI and FBC have incurred expenditures (O&M and capital) on innovation projects, activities and initiatives. For each area of the Current PBR Plan, please provide a detailed description of the expenditures and the annual amounts incurred in each area.

Response:

Please refer to the response to BCUC IR 1.73.2. Based on those categories, only the approximately $0.400 million that was identified for NGIF funding in 2018 was incurred from O&M for innovation funding. No amounts were identified for capital.

73.4 Please provide the amount of incremental funding to Base O&M which FEI and FBC are requesting for innovation-related activities during the proposed MRP term.

Response:

No incremental Base O&M funding has been requested. Please also refer to the response to BCUC IR 1.73.2.

73.5 Please provide the amount specifically related to Research and Development (R&D) activities that each of FEI and FBC has spent in each year of the Current PBR Plan term. Please express the amounts in absolute dollars terms and as a percentage of each utility's annual revenue requirement.

Response:

FortisBC has not categorized costs as R&D spending during the Current PBR Plan term; for discussion of innovation spending, which may capture some elements of R&D, please refer to the response to BCUC IR 1.73.2.

As described in Section C6.4.2 of the Application, the GGRR does not support pre-commercial activities. Similarly, DSM Innovative Technologies spending is defined under the Demand-Side Measures Regulation to support technology innovation, but is focussed on technologies that are commercial or near-commercial. Please refer to the responses to BCUC IRs 1.26.6 and 1.26.8 for detail on the NGIF and a description of the costs of the NGIF.

As discussed in Section C6.4.3.3 of the Application, the Clean Growth Innovation Fund will advance initiatives that fall with the range of the 'Research to Prove Feasibility' to 'System Test, Launch and Operation' technology readiness levels. Basic technology research is excluded from the Fund's commercialization focus. FortisBC will rely on industry participants such as academic institutions to advance basic technology research and instead focus on more mature levels of technology readiness described above.

73.6 Please estimate the amount specifically related to R&D activities that each of FEI and FBC anticipate spending during the proposed MRP term. Please express the amounts in absolute dollars terms and as a percentage of each utility's annual revenue requirement.

Response:

FortisBC makes no distinction between R&D spending and Innovation spending during the MRP term. All of the proposed pre-commercial innovation expenditures could be considered R&D.

During the Workshop, FortisBC stated the following:

> Those of you that were involved in the company's demand side management applications for both FEI and FBC are aware that we have an innovative

initiatives fund established there. And so what we're proposing here is really building on that foundation.[61]

73.7 Please provide a detailed description of the DSM Innovative Technologies program, including the annual and total funding available, what the funding has been used for since its inception (i.e. description of projects/programs by year and funds dispersed for each project/program), and what the funding is planned to be used for during the proposed MRP term.

Response:

The DSM Innovative Technologies Program Area represents a key component of FEI's and FBC's overall commitment to DSM activities. This area identifies viable technologies and projects that have the potential to support the development of new energy conservation programs within the larger DSM Conservation and Energy Management (C&EM) Portfolio and fosters the development of innovative technologies under BC's energy objectives.

Specifically, the Innovative Technologies Program Area evaluates both pre-commercial and commercially available technologies and conducts pilot studies to validate manufacturers' claims related to equipment and system performance. The program area also assesses actual savings and customer acceptance of these newer technologies or systems. Technologies that successfully emerge from the Innovative Technologies Program Area are considered for inclusion within the applicable sector programs within the larger C&EM portfolio. All activities undertaken within the Innovative Technologies Program Area meet the definition of a technology innovation program set out in the Demand-Side Measures Regulation (DSM Regulation). It should be noted that Innovative Technologies are considered to be a specified demand-side measure pursuant to the DSM Regulation, which means that the program and the technologies are evaluated as part of the DSM portfolio as a whole.

Pilot participants are selected based on the participants accepting program terms, monitoring requirements and meeting eligibility criteria, such as building type and its condition, appliance types, usage characteristics and location. The program requirements may vary from pilot to pilot depending on the objectives of the pilot and the technology being evaluated. Prior to the release of the rebate, those pilot participants must provide proof of payment, proof of install and respond to any survey data required.

The regulatory and accounting treatment of the DSM Innovative Technologies Program Area is the same as the overall C&EM Portfolio of offerings whereby the expenditure reports are filed annually and charged to a DSM deferral account that is amortized over ten years for both FEI

[61] T1: p. 41.

and FBC. All funding provided under the C&EM Portfolio meet Provincial requirements for adequacy and are in compliance with the Company's DSM Guiding Principles.

Since 2010, FEI received approval to dedicate a portion of DSM funds to evaluate innovative technologies while FBC received approval through the 2019-2022 Demand Side Management Expenditures proceeding. Table 1 breaks out approved funding from 2010 to 2022 compared to actual expenditures for FEI and Table 2 is for FBC. Details regarding the specific projects/programs offered across 2010-2018 along with a description and expenditure amount can be found in Attachment 73.7. Technologies that are planned to be evaluated from 2019 - 2022 can include, but are not limited to, transpired air collectors, recirculation demand controls, residential HVAC zoning, boiler cycling/zoning controls, commercial web-enabled thermostats, thermal bridging measures, rooftop unit controls and other technologies that meet the BC Energy Step Code Step 5 requirements, cold climate heat pumps, and connected home technologies.

Table 1: FEI DSM Innovative Technology Expenditure Summary

2010	$ 2,300,000	$ 5,959,000
2011	$ 4,669,000	$ 1,104,000
2012	$ 1,546,000	$ 394,000
2013	$ 1,502,000	$ 912,000
2014	$ 1,207,000	$ 522,000
2015	$ 1,218,000	$ 626,000
2016	$ 1,233,000	$ 757,000
2017	$ 1,218,000	$ 928,000
2018	$ 1,210,000	$ 1,183,000
2019	$ 2,043,000	n/a
2020	$ 2,202,000	n/a
2021	$ 2,631,000	n/a
2022	$ 3,062,000	n/a

Table 2: FBC DSM Innovative Technology Expenditure Summary

2019	$ 100,000	n/a
2020	$ 100,000	n/a
2021	$ 150,000	n/a
2022	$ 200,000	n/a

73.8 If not already provided in the previous IR response, please provide details of the innovative technologies or innovative initiatives funded through FEI's and FBC's DSM programs, including information on the following: (i) sources of the funds; (ii) method of collection; (iii) accounting and regulatory treatment of collected funds; (iv) disbursement process and project selection criteria; (v) key success indicators; and (vi) reporting requirements.

Response:

Please refer to the response to BCUC IR 1.73.7.

73.9 Please provide a detailed comparison of the proposed Innovation Fund and the innovative technologies funding through each of the DSM programs.

Response:

Please refer to Section C6.4.3.2 of the Application (page C-140) for a definition of activities that fall outside of DSM. The table below provides a comparison of the eligibility requirements for a technology, rate, action or program undertaken between the DSM Innovative Technologies funding and the Clean Growth Innovation Fund.

Funding Eligibility	DSM Innovative Technologies	Clean Growth Innovation Fund
To conserve energy or promote energy efficiency	Required	Not required
To reduce the energy demand a public utility must serve	Required	Not required
To shift the use of energy to periods of lower demand	Required	Not required
Fuel switching to natural or renewable gas	Not permitted	Permitted
Not commonly used in British Columbia	Required	Required
Load Growth	Not permitted	Permitted
DSM Portfolio Cost Effectiveness	Required	Not required
Reduces GHG Emissions	Not required	Required

73.9.1 Please explain how the Innovation Fund builds on the Innovative Technologies funding.

Response:

As discussed in the Application and illustrated in Figure C6-4, the Clean Growth Innovation Fund complements the Innovative Technologies funding and addresses crucial gaps. 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. In comparison, the Clean Growth Innovative Fund focuses on activities that cover the entire utility value chain, and are outside of demand side management, related to pre-commercial and commercial activities.

FortisBC has a successful and well-established Innovative Technologies program within its demand side management portfolio. The Clean Growth Innovation Fund builds on that success by utilizing similar management methodologies and by adding funding to existing initiatives where there may be benefits that meet the criteria for both funds.

For example, FortisBC is aware of micro-carbon capture technologies that not only scrub carbon from exhaust gases, but also recover waste heat. The carbon scrubbing benefit would fit within the mandate of the Clean Growth Innovation Fund and the waste heat recovery within the Innovative Technologies program funding.

73.9.2 Please explain why it would not be more appropriate for FortisBC to instead apply for additional DSM funding instead of the proposed Innovation Fund and rate rider.

Response:

As shown in Figure C6-4 of the Application, the Innovation Fund will be used to support innovative initiatives that would be ineligible, or only partly eligible, for DSM funding. Please also refer to the response to BCUC IR 1.73.9.1.

73.10 Please discuss the potential impacts on the following resulting from managing programs through different sources of funding (i.e. DSM and Innovation Fund/rate-rider):

- Administrative complexity;
- Ease of customer and stakeholder understanding;
- Internal review and reporting and complexity; and
- Transparency for regulatory reporting and review purposes.

Response:

The following response groups the first and third items, and the second and fourth items, as they are interconnected.

Administrative complexity + Internal review and reporting complexity

As described in the response to BCUC IR 1.73.9 series of questions, more than one fund is required to address funding gaps given the statutory limitations on what is eligible for DSM innovative technologies funding. It is possible that managing all activities under a single fund could be less complex to administer, review and report on than multiple plans. To capture efficiencies in managing both funds, FortisBC has established the governance committee structure shown in Figure C6-8 of the Application, which includes both the Clean Growth Innovation Fund and the DSM innovative technologies funding.

Ease of customer and stakeholder understanding + Transparency for regulatory reporting and review

FortisBC is amenable to communicating to customers and reporting at the Annual Review on all "innovation" funding as a whole rather than as two separate funds. FortisBC expects that there will continue to be a need for regulatory purposes to report on the Innovative Technologies program funding as part of DSM reporting requirements.

73.11 Please provide a detailed description of the projects and programs which fall within the GGRR. As part of this response, please provide the annual O&M and capital spending since the inception of the GGRR and what the spending has been for in each year. Please also provide the forecast annual O&M and capital spending and an accompanying description of the planned projects/initiatives to be undertaken during the proposed MRP term.

Response:

Prescribed undertakings under the GGRR enable FEI, and other public utilities in the Province, to invest in assets and programs to support objectives under the Clean Energy Act. Specifically, the GGRR enables investments in assets and incentive programs that enable reduction in GHG emissions in the transportation and remote power generation market segments in BC. The transportation market segment addressed by expenditures under the GGRR includes on-road medium and heavy-duty trucking, marine, rail locomotives and mine trucks. Remote power generation applications include remote communities and industrial customers to generate electricity by displacing higher GHG emitting fuels such as diesel fuel.

Furthermore, expenditures enabled under the GGRR are strictly applied to commercially available technologies and are not designed to support pre-commercial initiatives or investments. 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.

Expenditures for incentives under the GGRR are recovered from all non-bypass FEI customers through rates, while expenditures on infrastructure investments under the GGRR are recovered from participating NGT customers through rates that are approved by the BCUC.

The table below summarizes the actual expenditure by year for incentives under the GGRR, capital expenditure on NGT assets and O&M associated with NGT.

($000s)	2014	2015	2016	2017	2018
GGRR Incentives*	$9,966	$6,319	$4,767	$13,354	$10,074
NGT Capital	$5,816	$5,714	$5,857	$2,177	$1,744
NGT O&M	$484	$1,009	$1,205	$1,508	$2,099

**GGRR Incentive expenditures include expenditures on the following items as permitted under the GGRR: vehicle incentives, safety and maintenance shop upgrade incentives, admin/marketing/training expenditures*

As discussed in FEI's response to BCUC IR 1.2.5.3, FEI will prepare a forecast of O&M and capital related to investments of planned projects/initiatives over the MRP term in future Annual Review filings. Specifically, the forecast for 2020 will be included in FEI's Annual Review of 2020 Rates filing.

73.12 In consideration of the fact that FEI currently utilizes the GGRR provisions under the *Clean Energy Act* for certain capital investments which meet specific criteria for Prescribed Undertakings, please explain why an additional proposed funding source for innovation is necessary to achieve the objectives in the CleanBC Plan.

Response:

The expenditures permitted by the GGRR are described in the response to BCUC IR 1.73.11 and the type of expenditures contemplated in the Clean Growth Innovation Fund are described in Appendix C6-4 to the Application. The GGRR framework allows for infrastructure investments, incentives, administration, marketing, training and education related to certain commercial products and services that reduce greenhouse gas emissions in certain areas. The Clean Growth Innovation Fund allows for pre-commercial and commercial investments in innovative initiatives that are expected to accelerate the development of new, cleaner products and services. As such, investments in these innovative initiatives require a separate source of funding.

73.12.1 For each planned program/project under the proposed Innovation Fund, please explain why it could/would not already fall under various sections of the GGRR.

Response:

Please refer to the response to BCUC IR 1.73.12. The GGRR does not include any prescribed undertakings for investment in pre-commercial innovation, which is the primary purpose of the Clean Growth Innovation Fund and the activities described in Appendix C6-4 to the Application.

73.13 Aside from the proposed Innovation Fund, what alternative approaches to stimulating innovation activities to implement the Provincial (or Federal) Government's policies has FortisBC considered? Please explain in detail all of the approaches which were considered and why each approach was ultimately rejected.

Response:

As noted in Section C6.4 of the Application, FortisBC is already stimulating innovation activities through the DSM-enabled Innovation Technologies funding and GGRR-enabled funding for commercial NGT and RNG activities. In addition, FortisBC has been funding the NGIF through its Base O&M. FortisBC has not considered alternative approaches other than those identified.

73.13.1 Please compare and contrast the alternatives described in the above response, including the advantages and disadvantages for each option compared to the proposed Innovation Fund.

Response:

Primary differences in the alternative funding arrangements described in the response to BCUC IR 1.73.13 include:

- DSM innovative technologies is part of a separate application process, and the scope is constrained by the legislation, such as the definition of demand-side measures in the Clean Energy Act;
- Investments related to NGT and RNG under GGRR are limited by the scope of defined prescribed undertakings which do not include pre-commercial innovation expenditures; and
- Both DSM and GGRR expenditures are recovered through delivery (volumetric) rates rather than through a basic charge rate rider.

The primary disadvantage of the alternative approaches when considering their application to the Clean Growth Innovation Fund is that they are established under regulation for their specific purposes. The advantage of the Clean Growth Innovation fund is that it includes broad consideration of innovation and the advancement of technology and that its funding mechanism is designed to allocate costs to all customers equally.

73.14 Has FortisBC discussed other potential funding mechanisms with the Provincial Government, such as a province-wide approach, which could involve an innovation fund and funding mechanism that includes BC Hydro and/or other BC utilities? Please discuss.

Response:

FortisBC has discussed the MRPs, including general discussion of the Clean Growth Innovation Fund with the Ministry of Energy, Mines and Petroleum Resources. (Please refer to the response to BCUC IR 1.3.4 for a discussion of FortisBC's consultation on the Application). FortisBC continues to discuss opportunities for innovation and collaboration with the provincial government.

73.14.1 Please explain in detail the advantages and disadvantages of a province-wide funding approach.

Response:

The Clean Growth Innovative Fund is a province-wide funding approach insofar as it benefits FortisBC's customers throughout the Province.

Regarding the approach proposed in BCUC IR 1.73.14, ("an innovation fund and funding mechanism that includes BC Hydro and/or other BC utilities"), the primary potential disadvantage is that it reduces control and focus over innovation funds collected from FortisBC's customers and increases the potential for funds to be directed towards projects and initiatives that have no direct benefit to them.

Both the Provincial and Federal governments have had funding mechanisms that can be leveraged, but they are typically seeking partnership opportunities in order to spread their funding as far as possible. Examples of these mechanisms include the Provincial Innovative Clean Energy Fund (ICE) and the Federal contribution to the Natural Gas Innovation Fund (NGIF). The Clean Growth Innovation Fund would allow FortisBC to more effectively access these kinds of partnerships and ensure that funding was directed for those areas that most benefit our customers.

FortisBC has proposed a Clean Growth Innovation Fund which ensures benefits of innovation funding flow back to its customers and supports province-wide innovation projects and partnerships, provided they have a shared benefit for our customers. A guiding principle of the proposed Clean Growth Innovation Fund is to leverage partnerships with other organizations including governments, utilities, associations and innovative technology firms to provide greater access to capital, expertise and opportunities available.

73.14.2 Please explain in detail the advantages and disadvantages of having an external third-party administrator for an innovation fund and funding mechanism.

Response:

The disadvantage of a third-party innovation fund administrator, such as the NGIF, is that they may have an evaluation mechanism that results in different investment decisions than the members might make on their own. Conversely, the benefit of a third-party administrator like NGIF that accepts funding from multiple investors, is that FortisBC investments can be leveraged for innovations that have a common benefit to a number of investors. Accordingly, FortisBC believes that its proposed approach, which has the ability to include third-party administrators and direct partnerships with third-party innovation proponents, is the most flexible and practical.

73.15 Is FortisBC aware of whether BC Hydro has (or has proposed) a funding mechanism similar to FortisBC's proposed Innovation Fund and rate rider? Please discuss.

Response:

FortisBC is not aware of whether BC Hydro has (or has proposed) a similar funding mechanism.

74.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.2, p. C-132; Exhibit B-1-1, Appendix A5, p. 10

Investment in RNG

On page 10 of Appendix A5, FortisBC states the following:

> Growing BC's low-carbon fuel sector will require a number of actions from the province:
>
> - identify RNG as an essential component of the province's clean growth pathway
> - address regulatory barriers to expanding utility investment in RNG projects [*Emphasis added*]
> - streamline regulations to enable RNG production from agricultural waste
> - provide support to advance the commercial production of hydrogen as a form of RNG [*Emphasis added*]

74.1 In FortisBC's view, what are the regulatory barriers to expanding utility investment in RNG projects, and what actions are needed to address these barriers? Please discuss.

Response:

There is a clear policy environment in BC to promote the development of Renewable Natural Gas (RNG) projects. Since RNG supply acquisition and related utility investments constitute a prescribed undertaking under the GGRR, utility investments receive limited regulatory review based on projects complying with the criteria established by the GGRR including price and volume thresholds. The provincial government has also recently published the CleanBC Plan which further expresses the provincial government's desire to grow the supply and use of RNG.

To expand RNG supply consistent with the provincial goal of 15 percent renewable gas content, further increases in allowable price and volume are necessary, as well as broadening of the definition of renewable gases covered in the GGRR to include gases such as hydrogen. There is also clarity required on interpretation of some elements of the GGRR, such as how the ceiling price of $30/GJ applies to a biomethane project, rather than a biomethane supply contract.

The current CPCN threshold for non-GGRR biomethane projects appears to be inconsistent with the RNG objectives of the GGRR and the expanded CleanBC policy objective of achieving 15 percent renewable content in the gas supply stream. Given a $30/GJ ceiling price for RNG and very large supply targets, the current $5 million threshold for a non-GGRR CPCN is too low.

74.2 In FortisBC's view, what support is needed from the Provincial Government to support the advancement of the commercial production of hydrogen as a form of RNG, and how would that support impact FortisBC's need for the proposed Innovation Fund? Please discuss.

Response:

Policy and legislation support is needed from the Province to advance the commercial production of hydrogen. FortisBC understands the Province is currently developing a BC Hydrogen Roadmap, which will form the basis for such policy and legislative changes. Specifically, FortisBC anticipates the need for support in the following areas:

- Enabling regulation is needed to provide a legislative mandate to implement the CleanBC policy for renewable gases. Such regulation would need to provide flexibility in allowing the utilities to pursue innovation in achieving renewable gas and GHG reduction targets.
- Policy support is also needed to change and adapt existing technical regulations and to develop codes and standards for hydrogen injection at various blend concentrations.
- Additional financial support from government, in partnership with the Clean Growth Innovation Fund, is needed for R&D and pilot projects for the successful implementation of hydrogen.

74.3 Please generally discuss the availability and supply of raw biogas in BC, including where it can be harnessed, how it needs to be refined, and how it is injected into FEI's system.

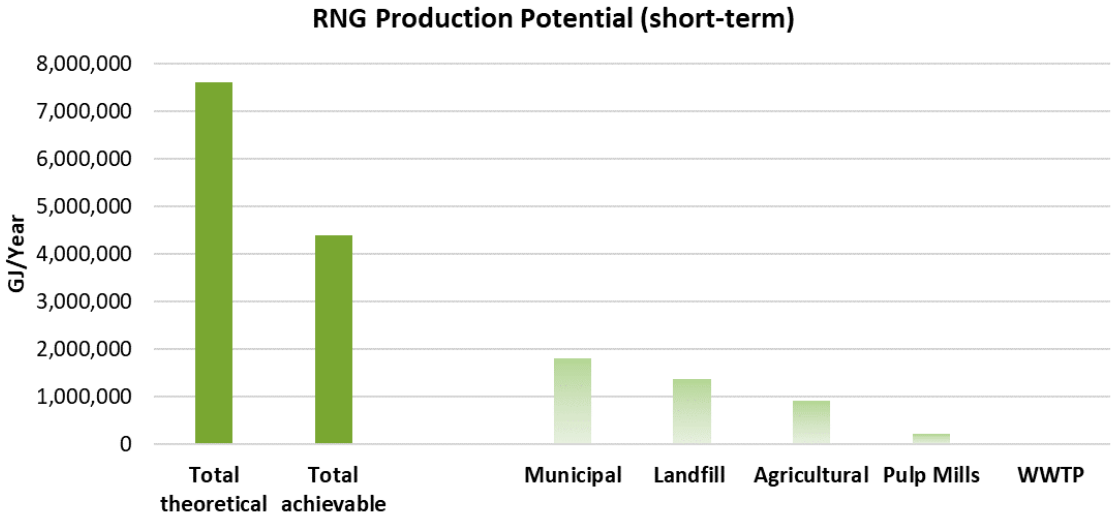
Response:

The supply potential study, prepared in 2016 by Hallbar for the Province of BC[62] indicated that there is between 8 and 12 PJ of RNG available in BC using existing methods for biogas

[62] Resource Supply Potential for Renewable Natural Gas in B.C. https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

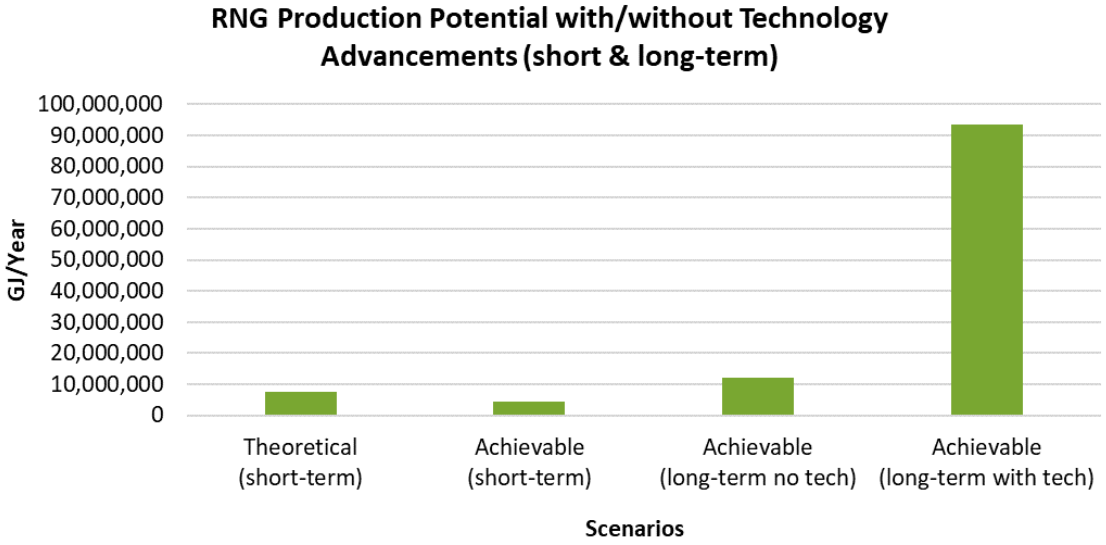
generation. This represents about 5 percent RNG content based on current natural gas use in BC, which is well short of the 15 percent policy target.

The study suggests that there are five primary sources of raw biogas that can be converted to RNG today and one future source. The sources of raw biogas available today (referred to as "conventional") are agricultural waste, commercial waste (food and food processing), municipal organic waste, and wastewater treatment plants and landfills. The future source of RNG is from wood-waste feedstock. Figure 3 from the Supply Potential Study (copied below for convenience) indicates the range of RNG in the short term (defined as before 2035) and shows the relative mix from the various sources in BC.



Conventional sources of raw biogas rely on a multi-step purification process which can vary by technology and feedstock source. This general process is currently being used in the five renewable gas plants operating within BC today.

The wood-waste process is currently under development and not commercially available, although it has the potential to increase RNG generation in BC to about 90 PJ annually according to the Hallbar study. Figure 2 from the study shows the relative potential in BC when considering wood-waste feedstock (see "Achievable (long-term with tech)").

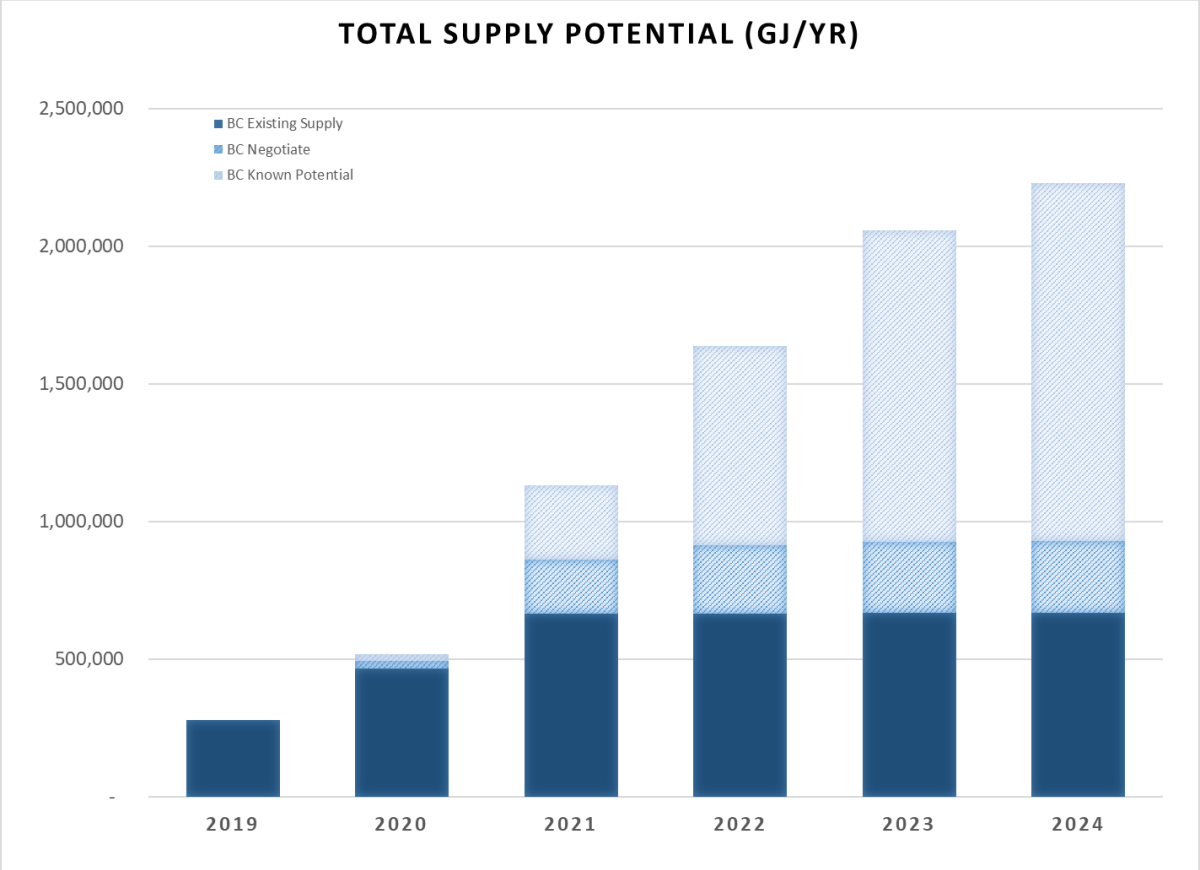


Despite the ongoing research and development of wood-waste technology, FEI believes that it will need to source RNG from outside of the province to achieve the 15 percent renewable gas policy goal by 2030. RNG sourced from outside of BC is both an expedient and an effective way to help reach the provincial government target. From a time-to-market perspective, there are shovel-ready projects in jurisdictions like Ontario that present an opportunity for BC and FEI's customers.

74.4 Please provide a high level forecast for the availability and supply of raw biogas in BC for the next five years.

Response:

FEI has developed a forecast for RNG Supply based on the projects which FEI has identified within BC. The figure below shows the existing RNG supply based on contracts that FEI has with suppliers, the potential supply from contracts under negotiation, and the potential beyond those categories. As discussed in the response to BCUC IR 1.74.3, the potential volume in BC, based on all possible opportunities, is much greater than the total amount shown in the figure.



74.5 Please discuss whether the recent amendments to the GGRR regarding RNG pricing provide FEI with a competitive advantage with regard to RNG supply.

Response:

FEI does not believe that the recent amendments to the GGRR provide a competitive advantage to FEI. Rather, the amendments provide a greater opportunity for a number of developers of RNG projects.

As FEI reviews a greater number of projects, it can more easily compare projects through an economic lens. This would imply that lower priced projects will be more attractive and ultimately could result in lower average prices for the acquisition of RNG.

The amendments have also provided an opportunity for FEI to broaden its view on the potential sources of renewable gas, such as supply from outside of BC. As a result of the higher volume

limit provided by the GGRR amendment and in order to identify new RNG supply opportunities and grow supply, FEI issued a Request for Expression of Interest (RFEOI) over the summer of 2018. The RFEOI resulted in more than thirty-three responses with a range of potential prices. The majority of the potential sources were from outside of BC.

Based on responses FEI received for its RFEOI, FEI sees an opportunity to secure RNG supply ahead of other jurisdictions, such as Alberta or Ontario, that do not have any current public plans to procure RNG. Because FEI is one of the first utilities to acquire RNG, it has the advantage of securing RNG at better prices than if it were competing for the gas with other jurisdictions.

The responses to FEI's RFEOI and the range of prices seen for acquisition of RNG would imply that the GGRR facilitated a more competitive landscape for RNG.

On page C-132 of the Application, FortisBC states the following:

> 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 5 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 10 FortisBC's gas system, 15 percent renewable gas would require approximately 30 petajoules 11 (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. [*Emphasis added*]

74.6 Please provide estimates along with supporting data for investments that FortisBC needs to make in innovation in order to achieve a 100-times scaling of renewable gas supply in the next 11 years.

Response:

The Companies cannot predict the amounting of funding in research and innovation that the Companies will require in order to achieve a 100-times scaling of renewable gas supply by

2030. The Companies will not be the sole source of funding for the development of the technologies needed to achieve these levels of renewable gas supply; funding will also be provided by governments and by other commercial entities, so the level of funding required from FortisBC will to some degree be dependent on the levels of funding and on funding criteria (for example the need for matching funds) for other funding programs. Also, the level and type of technology advancement cannot be predicted over an 11 year period. For example, funding required will be dependent on how quickly technology advances.

In Section C6 of the Application, and in Section 1.2 of Appendix C6-4 to the Application, FortisBC discusses the need for utility investment in innovation activities generally, and more specifically in renewable gases. FEI sees an immediate need for investments of $4.9 million annually in innovation activities over the proposed term for this MRP.

75.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section B1.4, pp. B-15 – B-17; Workshop Transcript, pp. 41, 50

Stakeholder Engagement

On page B-15 of the Application, FortisBC states the following:

> 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.

During the Workshop, FortisBC stated the following:

> Many of you in the room had the chance to already hear from me about this fund as we were developing it and I've been pleased by the feedback we've had so far.[63]
>
> …
>
> Aside from the stakeholder engagement we've already undergone, we haven't gone out and reached out to the public broadly. We do know that customers support clean technologies overall and so – and you know, our polling shows that customers, obviously, are interested in keeping rates reasonable but they are also interested in their utilities pursuing clean innovations.[64]

75.1 Please discuss FortisBC's consultation process specifically regarding the proposed Innovation Fund. Please provide the dates and the list of stakeholders (customers, Government, interveners, etc.) who participated in the consultation process.

Response:

The discussions with stakeholders regarding the proposed Clean Growth Innovation Fund were included as part of the overall consultation process regarding the Application. Please refer to FortisBC's response to BCUC IR 1.3.4 for detailed discussion of this process.

[63] T1: p. 41.
[64] T1: p. 50.

Please also refer to FortisBC's discussion in Section B2.5 of the Application (page B-59) regarding the Update on FortisBC Next Generation Rate Making Approach sessions held in October 2018.

FortisBC met with stakeholders regarding the Application where the proposed Clean Growth Innovation Fund was discussed, as follows:

Date	Stakeholder Organization
October 1, 2018	BCSEA
October 9, 2018	ICG
October 9, 2018	MoveUP
October 10, 2018	BCMEU
October 16, 2018	BCOAPO
October 16, 2018	CEC
October 17, 2018	BCUC Staff

Finally, FortisBC met with representatives from the Ministry of Energy, Mines and Petroleum Resources and the BC Business Council as part of the Application consultation process which included a discussion of the Clean Growth Innovation Fund.

75.1.1 Please explain if FortisBC conducted separate consultation processes for FEI and FBC. If no, please explain why not and whether separate consultation processes would be appropriate given the utilities' different operating environments.

Response:

FortisBC did not conduct separate consultation processes for FEI and FBC.

As the proposed Clean Growth Innovation Fund is designed to address both FEI and FBC's Innovative Technologies needs and that many of the stakeholder organizations and representatives were the same for both FEI and FBC (i.e. MEMPR, BCOAPO, MoveUP, CEC and BCSEA), a joint consultation process accomplished the same objective in providing a forum for stakeholders to consider a Clean Growth Innovation Fund while recognizing that FEI and FBC have differing operating environments.

75.2 Please discuss the information provided by FortisBC for each of FEI and FBC during the consultation process and the feedback received for each of FEI and FBC with respect to:

- The purpose and main objective of the Innovation Fund;
- Proposed methodology and quantum of the rate-riders; and
- Proposed areas of R&D and/or projects to undertake.

Response:

Following are three slides regarding the Clean Growth Innovation Fund used by FortisBC during the October 2018 Update on FortisBC Next Generation Rate Making Approach consultation sessions. Please refer to Appendix C3-1 of the Application for a complete copy of the material used.

Innovation funding principles

- Use a portfolio approach to diversify risks
- Leverage partnerships
- Manage portfolio centrally to ensure maximum value
- Pursue innovations with strong consumer interest and/or policy benefit
- Leverage FortisBC's regulated assets and expertise
- Focus on technologies that have focus on solutions that address challenges and opportunities unique to BC or are otherwise undeveloped

12

1

Innovation funding initiatives

- New RNG sources
- Using hydrogen to decarbonize natural gas
- EV charging technologies
- Carbon capture technologies
- Behind the meter
- Natural gas and hydrogen for transportation

13

2

3 The slides provided an overview of the purpose and objectives of the Clean Growth Innovation
4 Fund, the funding principles for the Fund, and areas of R&D and/or projects being considered.

The following are some of the questions and comments received from stakeholders during the MRP consultation sessions, focused mostly on clarification of the Clean Growth Innovation Fund:

- What does “manage portfolio centrally” under the guiding principles mean?
- Is the innovation initiatives mostly O&M expenditures?
- Is it hydrogen from electrolysis?
- How have you been engaging with customers to determine their interest in the R&D initiatives?
- Are any of the Innovation funding initiatives possible NRB opportunities later on?
- Is the proposed R&D funding going to be in addition to the GGRR funding? Will you be using a rate rider to fund the R&D activities?
- How does FortisBC’s proposed level of funding compare to other jurisdictions? What is the process you will be using to determine which initiatives to undertake?

In addition to the October 2018 sessions, FortisBC held a workshop on December 14, 2018 regarding the Review of Multi-Year Rate Plans and Cost of Service Regulation. As part of the workshop, FortisBC asked stakeholders a number of questions in an online survey. One of the questions was on the funding level per customer in support of Innovation Technologies.

Appendix C3 - Stakeholder Communications

Q5. Advancing the development of Innovative Technologies for the benefit of customers and to support government policy will be a key theme of FortisBC's next ratemaking application. FortisBC intends to apply for funding to support research and development and pilot programs. Please choose one of the following options indicating how much you think customers are willing to pay to support Innovation Technologies.

Total: 3 participants

		Total
	Total	3
1	Up to $5 per customer per year	1
		33%
2	Between $5 and $10 per customer per year	1
		33%
3	Greater than $10 per customer per year	1
		33%

The stakeholder responses (although limited) to question 5 above showed general support and willingness from customers in paying to support Innovative Technologies. Please refer to page

B-62 and Appendix C3-2 of the Application for further discussion and details of responses received.

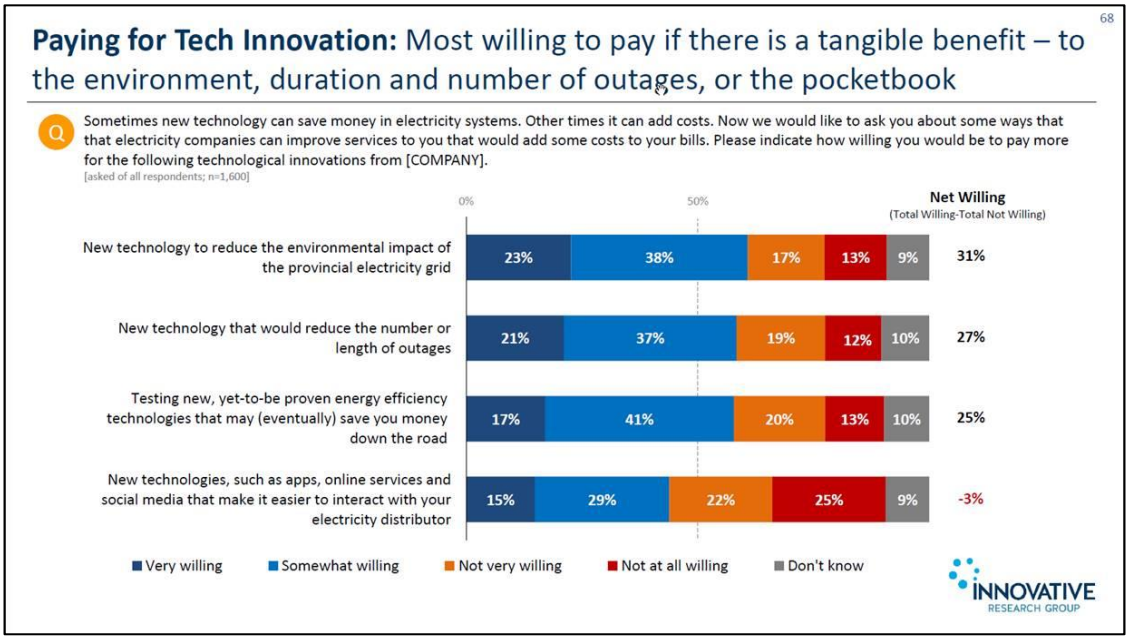
75.3 Please discuss to what extent the results of customer and stakeholder feedback were considered. Please provide specific references to the Innovation Fund's design and features as part of this response.

Response:

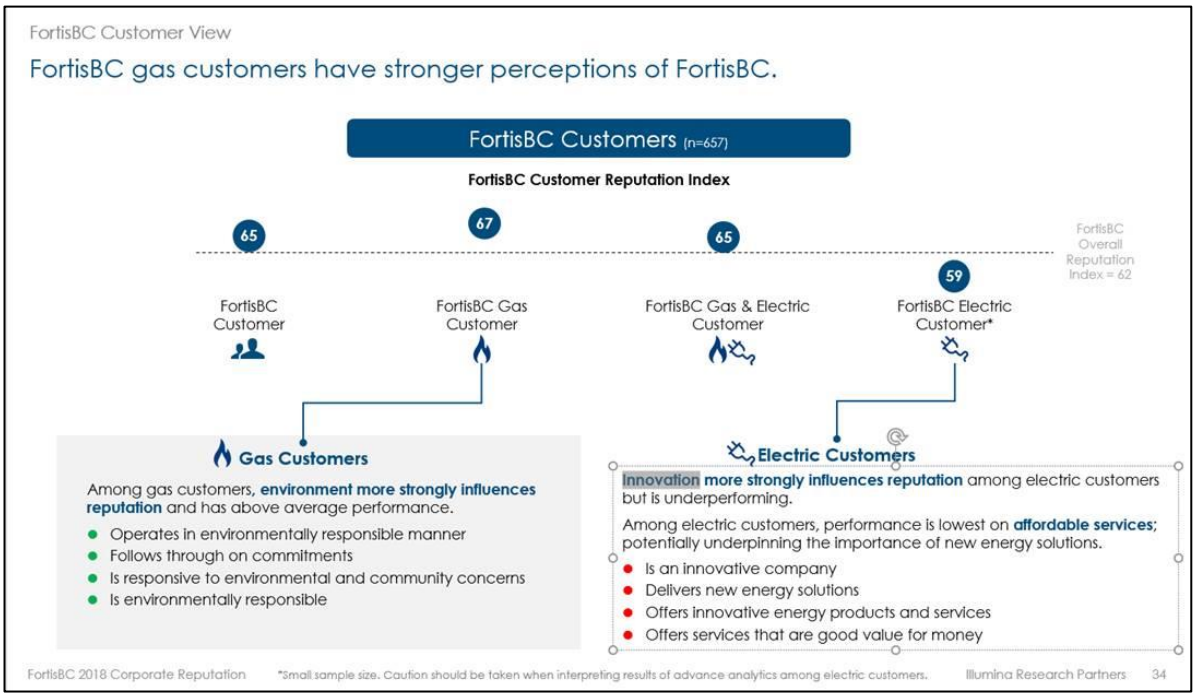
With respect to stakeholders referenced in the response to BCUC IR 1.75.2, there were a number of questions asked, but limited feedback provided to FortisBC. FortisBC is proposing a rate rider for the Clean Growth Innovation Fund that is in the lower range of the survey question posed to interveners regarding how much customers would be willing to pay (please refer to the response to BCUC IR 1.75.2).

Other feedback sources that were considered include:

- FortisBC Attitudes Survey show that customers are willing to pay for "innovation" if there is an environmental benefit. Environmental innovation is a key design feature of the Innovation Fund.



- FortisBC 2018 Corporate Reputation Presentation showing that "innovation" and "environment" are important to FortisBC customers. Environmental innovation is a key design feature of the Innovation Fund.



Please also refer to the response to CEC IR 1.33.2.

75.4 Please discuss FortisBC's plans to reach out to the public broadly with respect to the proposed Innovation Fund, specifically regarding how the fund will be collected, what it will be used for, and the bill impact to customers.

Response:

If approved, FortisBC will reach out to customers to ensure they are informed regarding the proposed Clean Growth Innovation Fund. We will use a variety of communication methods, including bill messages (both paper and electronic), information links on the secure online account portal and detailed information at fortisbc.com.

75.4.1 Please explain if FEI and FBC anticipate any negative reactions to the proposed rate-riders, and if so, how FortisBC will respond to and address such reactions.

Response:

FortisBC expects limited negative reaction to the proposed rate riders. However, to the extent that customers have concerns or questions about the rate rider, or any other charge on their bill, FortisBC will work directly with the customer through its call centre staff to address their concerns.

75.5 What is FortisBC's understanding of general customer acceptance for cost recovery of expenses within the delivery charge versus rate riders? What are the pros and cons of each method? How does FortisBC plan to address customer concerns with the billing mechanism? Please discuss and respond separately for each of FEI and FBC.

Response:

In the response below, FortisBC utilizes the term "volumetric rate" rather than "delivery rate" since the Innovation Fund applies to both FEI and FBC. FortisBC sets out below the two approaches for recovery of costs that would be applied to funding the Clean Growth Innovation Fund, if approved. There are no considerations that are different for FEI and FBC.

1. Add a rate rider to the fixed basic charges to accumulate the funds. The rate rider would be embedded in the basic charge on a customer's bill, similar to how other approved rate riders are included on a customer's bill.

2. Include the cost as a forecast in the Revenue Requirement. The cost would be embedded in the requested rate change and recovered through volumetric rates.[65]

FortisBC sets out below the differences between the two approaches – whether they are seen as pros or cons will depend on the objectives.

[65] FBC would also recover funds through their basic charge as it changes with approved rate changes.

Method 1:

- Is appropriate if the goal is to collect the same amount from all customers, which assumes that all customers should benefit equally from the amounts collected
- Greater transparency of costs and recoveries

Method 2:

- Is appropriate if the goal is to collect more from higher volume customers, which assumes that higher volume customers will benefit more
- Less variability in the amount recovered each year (rate will be set to recover exactly the amount forecast rather than varying depending on the number of customers in the year)

FortisBC believes that most customers do not understand the difference between why expenses are recovered through volumetric rates or through the fixed basic charge. Most customers are aware of cost increases in general, regardless of where they show up on their bill. As such, FortisBC does not anticipate concerns with respect to where the charge is applied (basic charge or volumetric charge), but that concerns, if any, will be related to the increase on a customer's bill. Should customers inquire about the increase to their bills, FortisBC would address customer concerns according to our typical practice, which is to provide our Customer Service Representatives with information on how they can respond to customer concerns of this nature.

76.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6, pp. C-128 – C-146; Exhibit B-1-1, Appendix C6

Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation

On page C-133 of the Application, FortisBC states the following:

> 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 "Regulatory Rationale for Ratepayer Funded Electricity and Natural Gas Innovation" prepared by Concentric Energy Advisors. 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.

As Appendix C6 to the Application, FortisBC provided a report prepared by Concentric Energy Advisors (Concentric) titled "Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation" (Innovation Report).

76.1 Please confirm, or explain otherwise, that the Innovation Report provided in Appendix C6, and referenced by FortisBC on page C-133 of the Application, was not prepared specifically for FEI or FBC.

Response:

Confirmed. As indicated on the title page of the report, the report was prepared for the Canadian Gas Association and the Canadian Electricity Association.

76.2 Please explain the specific purpose and objectives of the Innovation Report, including the terms of reference which were provided to Concentric when preparing this report.

Response:

The Canadian Gas Association (CGA) and the Canadian Electric Association (CEA) selected Concentric Energy Advisors (Concentric) to write the report contained in Appendix C6-1 of the Application, based on their knowledge, expertise and experience in understanding the issues facing energy utilities as well as their work with the CGA and CEA in the area of utility-led innovation since 2013.

The specific purpose of the report contained in Appendix C6-1 of the Application was to examine the role that Canada's utilities and regulators play in promoting innovation. In particular, the report was to assist in enhancing knowledge of innovation programs approved by regulators or otherwise mandated through policy direction across jurisdictions, including the supporting rationale or justification for innovation funding.

The scope of work was defined as:

1. Referring to the 2014 Concentric Report, Stimulating Innovation on Behalf of Canadas's Electric and Natural Gas Consumers Study, Attachment B[66], study of programs that are state or regulator mandated:
    a. The Commission or Board rationale for the original determination;
    b. A web link to the final decision of the stat or regulator where the full record of the proceeding can be accessed; and
    c. Any notable updates made by the state or regulator since it original decision approving a mandated fund, set aside or in rates levy/mechanism.
2. A Q&A with 5-6 regulators or fund CEO's leads (Ofgem, US states, ICE Fund, etc.) on the process from conception to reality on their innovation levy, discussing:
    a. The history and how it came to be;
    b. What challenges they faced;
    c. What considerations led them to approve the program (question for regulators), or positions that had the most influence on the regulator (question for fund leads);
    d. How the regulator is kept informed/engaged in how the money is spent and the overall governance structure established; and
    e. How they think the program is working.

[66] http://ceadvisors.com/wp-content/uploads/2015/10/CGA_CEA-Report.pdf

3. A summary of additional countries that are actively pursuing an innovation levy/mechanism (e.g., Australia – electric) and the outcome of their proceedings.

4. Referring to the 2014 Concentric Report, Stimulating Innovation on Behalf of Canadas's Electric and Natural Gas Consumers Study, Attachment A67, an update to Figure 2 (Funding Levels/Customer) – for researched programs.

Please also refer to the Introduction on page 8 of the Concentric report included in Appendix C6-1, for a discussion of the development of reports prepared by Concentric for the CEA and CGA leading up to this report.

76.2.1 As part of the above response, please explain why Concentric was chosen to prepare the Innovation Report.

Response:

Please refer to the response to BCUC IR 1.76.2.

[67] http://ceadvisors.com/wp-content/uploads/2015/10/CGA_CEA-Report.pdf.

77.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.3.3, pp. C-134 – C-137; Appendix C6-1

Evolution of Innovation Funding

On pages C-134 through C-137 of the Application, FortisBC describes three case studies which it states illustrate "the importance of collective responsibility in advancing innovation." The three case studies are: (i) the United Kingdom's Revenue using Incentives to deliver Innovation and Outputs (RIIO) Framework; (ii) New York State's Millennium Fund; and (iii) Ontario's Low Carbon Initiative Fund.

FortisBC further states on page C-134 of the Application that Ofgem, the regulator of energy network companies in the United Kingdom (UK), implemented the RIIO Framework in 2013 (RIIO-1).

77.1 Please provide a detailed comparison of the natural gas and the electric utility industry and operating environment in BC versus the UK. Please include as part of this response the number and size of natural gas and electric utilities compared to BC, and how FEI and FBC compare in terms of volumes delivered and number of customers to the UK utilities.

Response:

There are fourteen licensed electric distribution network operators (DNOs) in the UK which operate under six investor-owned corporations. Combined, the electric utilities provide approximately 307 TWh of energy to 28 million customers annually. Eight licensed gas DNOs operate under four investor-owned corporations in the UK, providing more than 3,500 PJs of natural gas to 23 million customers annually. These figures contrast with BC's operating environment. In BC there is one crown-owned electric utility as well as four investor-owned electric utilities and multiple, small-scale municipal utilities. As the second largest electric utility in the province, FBC provides approximately 3.3 TWh of electricity to 170,000 customers annually. There are two leading investor-owned natural gas utilities, as well as multiple smaller, municipal gas utilities in BC. FEI, the leading gas utility in the province, provides more than 200 PJs of natural gas to over 1 million customers annually.

Both electric and gas utilities in the UK operate under a competitive environment. Independent Connection Providers (ICPs) and licensed Independent Distribution Network Operators (IDNOs) can compete with Distribution Network Operators (DNOs) to connect new customers to the natural gas or electric grid. In BC, independent gas marketers can compete with natural gas distribution utilities to provide gas to customers; however, no such choice is provided for BC's electricity industry.

Utilities in both British Columbia and the United Kingdom are continually adapting to a shifting operating environment as a result of progressing decarbonization policy targets from their

respective governments. Major recommendations from the UK's Committee on Climate Change (CCC) were recently passed into law including a target for 80% GHG reductions below 1990 levels by 2050. Recent CCC recommendations emphasize policy action to develop low carbon heating, hydrogen, carbon capture and storage (CCS) and energy efficiency measures as a means to realize deep carbon emissions reductions.

In the UK, there has been significant political commitment to actively reduce carbon emissions and advance clean energy programs. This is present through key climate mandates such as legally binding carbon budgets, which cap national emissions on a five-year basis. As a result of these commitments, the UK has seen a 38% in GHG reductions from 1990 levels, a leading figure amongst developed nations, whereas jurisdictions such as BC have seen relatively static GHG emissions values over recent years. Comparably, BC's provincial climate action plan, CleanBC, sets a similar 2050 target for GHG reductions with a key emphasis on the decarbonization of buildings, energy efficiency and CCS technologies. CleanBC also contains a 15% renewable gas content requirement, which is considered as an aggressive, world leading climate action initiative. As a result of the climate policy context in both jurisdictions, utilities are seeking to rapidly decarbonize their respective energy supplies which will require significant investments in innovative technologies.

Task Item	British Columbia	United Kingdom
Key Climate Policy Mandates	• 80% GHG Reductions from 2007 Levels by 2050 (provincial) • DSM Regulation (provincial)- Public Utilities must include demand side measures that assist low-income households in reducing energy consumption, improve energy efficiency in rental properties, establish an education program and local communities in adopting more stringent building codes. • 15% Renewable Gas Content Requirement for Industrial and Consumer end-use applications (provincial) • BC Energy Step Code (Provincial) • Clean Fuel Stand (Federal)- Increase the use of lower carbon fuels, energy sources and technologies. • Climate Change Accountability Act (Provincial)-GHG Reductions 40 per cent below 2007 levels by 2030, 60 per	• 80% GHG Reductions from 1990 levels by 2050 • The Energy Company Obligation (ECO)- statutory scheme that places an obligation on energy suppliers to deliver energy efficiency and provide support to low income, vulnerable and fuel poor households. • Upgrade fuel poor homes to an energy performance certificate (EPC) rating of C or better by 2030 • Legally binding carbon budgets to cap emissions on a 5 year basis • CCC recommendation for a ban of new connections to the natural gas grid by 2025. This proposal is not currently legislated and is planned to go out for consultation this year. • CCC recommends increasing biomethane injection to the grid until 2030 (reaching 4% of current supply) to reduce short-term emissions • EU Emissions Trading System- EU-wide cap on the number of available carbon allowances. Current carbon allowances trading at £21.41/ton CO2e.

Task Item	British Columbia	United Kingdom
	cent by 2040, and 80 per cent by 2050 • Carbon tax (Provincial)- $40/ton CO2e	• Carbon Price Support (Domestically imposed)- capped at £18.08/ton CO2e until 2021
Mandate of the Utility Regulator	• Protects consumers and ensures prices are fair • Ensures utilities have the opportunity to get reasonable returns • Delivers Government programs[68]	• Protects consumers and ensures prices are fair • Promoting security of supply • Promoting sustainability • Delivering government programmes.[69]
Number of Licensed Electric Utilities	1 crown-owned utility, 4 investor-owned utilities, multiple small scale municipal-owned utilities.[70]	14 utilities operating under 6 investor-owned corporations.[71]
Number of Electric Customers	Approximately 170,000 (FortisBC)	Approximately 28 million
Annual Electricity Delivered	3.3 TWh per annum (FortisBC)	307 TWh per annum
Number of Licensed Gas Utilities	2 leading investor-owned utilities, multiple small scale investor-owned and municipal-owned utilities[72]	8 utilities operating under 4 investor-owned corporations[73]
Number of Gas Customers	Approximately 1 million (Fortis Energy Inc.)	Approximately 23 million
Annual Gas Delivered	200+ PJs per annum (Fortis Energy Inc.)	3,500+ PJs per annum

77.2 Please provide a detailed comparison of the regulatory environment in BC versus the UK with respect to natural gas and electric utilities. As part of this response,

68 https://www.bcuc.com/about/who-we-are.html.
69 https://www.ofgem.gov.uk/about-us/how-we-work.
70 https://www.bcuc.com/consumers/consumer-information.html.
71 https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network.
72 https://www.bcuc.com/consumers/consumer-information.html.
73 https://www.ofgem.gov.uk/gas/distribution-networks/gb-gas-distribution-network.

please compare Ofgem's role as a regulator and its mandate to the BCUC's role and mandate.

Response:

Item	BCUC - BC	Ofgem- UK
Are energy markets privatized – can consumers choose their energy providers?	There are two major energy providers, BC Hydro and FortisBC	Energy markets are privatized. [74]
Who do the regulators oversee?	Area of oversight include: Natural Gas utilities, Electricity utilities, intra-provincial pipelines, universal compulsory automobile insurance.[75]	Regulates natural gas and electricity. [i]
What is the role and mandate of the regulator?	The BCUC's mission is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. [76]	Ofgem's principal objective is to protect the interests of existing and future electricity and gas customers. This is done in a variety of ways: • Promoting value for money • Promoting security of supply and sustainability, for present and future generations of consumers, domestic and industrial users • The supervision and development of markets and competition • Regulation and the delivery of government schemes. [77]
How do the regulators engage stakeholders?	Most applications are considered through open public hearings and the public has an opportunity to participate in the hearings. [ii]	Engages with consumer organizations through forums such as the Consumer First Panel, energy industry, environmental groups, government and the city. Has working groups, events, and provides consultation. [iii]
How is the regulator funded?	The BCUC has been self-funded since 1988. Its costs are recovered primarily through a levy on the businesses it regulates. [78]	Recovers costs from licensed companies they regulate. Licensees must pay an annual license fee which is set to cover costs. [79]

[74] https://www.ofgem.gov.uk/sites/default/files/docs/2001/11/deregulation-of-supply-markets---slides-26-11_0.pdf
[75] https://www.bcuc.com/about/our-role.html
[76] https://www.bcuc.com/about/who-we-are.html
[77] https://www.ofgem.gov.uk/about-us/who-we-are
[78] https://www.bcuc.com/about/

Item	BCUC - BC	Ofgem- UK
Is there a complaint process for stakeholders?	The BCUC commonly receives complaints and inquiries about regulated energy utilities, as well as complaints regarding ICBC's basic automobile insurance rates.[80]	Provides consumers with transparent resources to educate themselves about energy, choose energy providers, provide feedback and complaints towards suppliers of energy. [81]
Who governs the regulator?	Governed by Utilities Commission Act. [82]	Is governed by the Gas and Electricity Markets Authority (GEMA). [iv]
What kind of judicial powers, if any does the regulator have?	Quasi-judicial entity. Can issue administrative penalties and investigate companies.[83]	Has the power to require disclosure of information, impose fines and enforcement orders on company where a breach has occurred. Ensures that companies comply with the law, can make orders to secure compliance. Cannot make laws. [84]

[79] https://www.ofgem.gov.uk/about-us/who-we-are/gas-and-electricity-markets-authority
[80] https://www.bcuc.com/consumers/utility-icbc-complaint-process.html
[81] https://www.ofgem.gov.uk/about-us/how-we-engage/engaging-consumer-issues.
[82] http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01#part1.
[83] https://www.bcuc.com/about/who-we-are.html.
[84] https://www.ofgem.gov.uk/about-us/how-we-work/our-approach-regulation.

Item	BCUC - BC	Ofgem- UK
What kind of sustainability initiatives does the regulator promote?	BCUC invites comments on projects from many different environmental organizations and also follows the energy objectives outlined in the Clean Energy Act and applies them to the utilities it regulates. BCUC is currently considering proposals for in-house sustainability funds like the Innovation Fund. [85]	Ofgem delivers renewable energy and social programmes on behalf of government. Their expertise lies in designing, setting up and delivering large scale programmes in the sustainable energy sector. These programmes are in fields as diverse as renewable heat, renewable electricity, energy efficiency and fuel poverty. Ofgem works with energy companies, consumer groups and other stakeholders, including the UK's elected representatives, to make sure policy targets are met in the most economical and consumer conscious way possible. [86] These are just some of the initiatives that are administered from Ofgem: • Low Carbon Network Fund – provides up to $500 million of funding to support projects for utilities that trial new technology, operating and commercial arrangements. • Innovation Competitions – companies can compete for funding for the research, development and demonstration of new technology. Initiatives like these are aimed at helping transition the UK to a low carbon economy. [87]

[i] https://www.ovoenergy.com/guides/energy-guides/ofgem.html
[ii] https://www.bcuc.com/get-involved/understanding-process.html
[iii] https://www.ofgem.gov.uk/about-us/how-we-engage
[iv] https://www.ofgem.gov.uk/about-us/who-we-are/gas-and-electricity-markets-authority

77.3 Please provide a detailed comparison of FortisBC's proposed Innovation Fund and the Ofgem RIIO Framework innovation stimulus, including the following:

- Method of collecting the funds from consumers;
- Who can access the funds and how the funds are accessed;

[85] https://www.bcauditor.com/sites/default/files/publications/reports/FINAL_BCUC.pdf.
[86] https://www.ofgem.gov.uk/environmental-programmes/environmental-programmes-ofgem-s-role-and-delivery-performance.
[87] https://www.ofgem.gov.uk/electricity/transmission-networks/network-innovation.

- How the funds are administered and managed;
- Selection criteria for projects to be funded; and
- Competitiveness of the funding award process.

Response:

The RIIO-1 Innovation Stimulus Framework provides funding to utilities and third parties that successfully implement new commercial and charging arrangements to help deliver a more sustainable energy sector. Funding is open to projects at any point in the innovation cycle. Participation in the funding scheme by network and non-network parties alike would be contingent on holding an 'Innovation License' which would authorize the holder to receive and, in the case of networks, disburse monies under the scheme. The RIIO-1 Innovation Stimulus is funded from the use of system charges through networks, which are recouped from consumers. The amount raised is a pass-through cost in the price controls of the regulated network companies.

Ofgem administers the innovation stimulus funding in two pots: one for electric and one for gas. From this point, funding is allocated into three tranches to cover distinct categories of projects: a Network Innovation Competition (NIC) for flagship projects, an up-front Network Innovation Allowance (NIA) for small-scale innovation projects and an Innovation Roll-Out Mechanism (IRM) to transition proven innovations to Business As Usual (BAU). The innovation funding is largely allocated through a competitive process. For each potential project, Network Operators or third parties submit a project outline during an initial screening process to Ofgem, who then decides which projects will advance to the full submission stage. While Ofgem makes the final decision on project submission, they do so with advice from an independent panel of experts.

The disaggregated nature of the UK's natural gas market has allowed many large-scale utility distribution companies the chance to operate within a competitive environment. Therefore, programs, such as Innovation Funds, require a centralized administrative process through a single governing body, such as the utility regulator. In comparison, FortisBC's Clean Growth Innovation Fund would be administered by FortisBC for innovation projects at all stages of the value chain to maximize the utilization of its natural gas and electric assets in an evolving climate policy context. With essentially one major natural gas utility in the province, the administration and management of innovation funding can be centrally managed under the purveyance of FortisBC. This will allow for greater coordination and efficient execution of project implementation.

Funding for FortisBC's stimulus would be collected through a basic charge rider. This would apply equally to customers across the gas network ($0.40/month) and the FBC electric service territory ($0.30/month) to ensure that all customers are covering the costs of innovation funding. The fund would receive feedback from an External Advisory Council to ensure that innovation projects are in alignment with the fund's purpose, objectives and guiding principles. Internally,

FortisBC's fund would be managed by an Executive Steering Committee and an Innovation Working Group with sector-specific experts from the gas and electric divisions. In contrast to the RIIO-1 Innovation Stimulus, FortisBC's fund would be allocated solely to the FortisBC companies. However, FortisBC would communicate the range of program outcomes to the BCUC in the Companies' annual reporting to ensure an accountable and transparent oversight process.

Item	FortisBC Innovation Fund	RIIO-1 Innovation Stimulus
Method of collecting funds from the consumer	Funding for FortisBC's stimulus would be collected through a basic charge rider. This would apply equally to customers across the gas network ($0.40/month) and the FBC electric service territory ($0.30/month)	The Stimulus is funded from the use of system charges through networks, which are recouped from consumers. The amount raised is a pass-through cost in the price controls of the regulated network companies
Who can access the funds and how the funds are managed	FortisBC can access the funds with the potential to award funding to private sector organizations, the public sector or research institutions moving forward.	Utilities and third parties that successfully implement new commercial and charging arrangements to help deliver a more sustainable energy sector. Participation is contingent on holding an 'Innovation License' which would authorize the holder to receive and, in the case of networks, disburse monies under the scheme.
How the funds are administered and managed	The fund would be administered by the FortisBC Companies. It would be internally managed by an Executive Steering Committee and an Innovation Working Group with sector-specific experts from the gas and electric divisions. The fund would receive feedback from an External Advisory Council to ensure alignment with the fund's guiding principles and objectives.	Ofgem administers the innovation stimulus funding in two pots: one for electric and one for gas. Funding is allocated into three tranches: a Network Innovation Competition (NIC) for flagship projects, an up-front Network Innovation Allowance (NIA) for small-scale innovation projects and an Innovation Roll-Out Mechanism (IRM) to transition proven innovations to Business As Usual (BAU).
Selection Criteria for Projects to be Funded	The fund applies to innovation projects at all stages of the value chain to maximize the utilization of FortisBC's natural gas and electric assets in an evolving climate policy context. Criteria for consideration would include GHG reduction potential, impact on ratepayers, technological readiness, additional third party funding availability as well as the number of potential partner organizations.	Funding is open to projects at any point in the innovation cycle intended to deliver a more sustainable energy sector. The fund seeks to support trials that may otherwise not take place within the price control framework. All project funds must generate learnings for all companies involved, and these learnings must be shared. NIA Criteria: Ofgem assesses the quality of the applicant's innovation strategy within their business plan. If the strategy passes assessment, Ofgem sets the NIA at 0.5-1.0%

Item	FortisBC Innovation Fund	RIIO-1 Innovation Stimulus
		of base revenue. NIC Criteria: Projects must have potential for carbon or other environmental benefits, consumer benefits and be of sufficient quality. IRM Criteria: Projects must demonstrate environmental benefit, long-term value for money, and material outputs or end-products to assess the roll-out.
Competitiveness of the Funding Award Process	FortisBC's fund would be initially allocated to the FortisBC companies, with the potential to award funding to or partner with private sector organizations, the public sector or research institutions moving forward. Dependent on the quality and number of partner organizations for potential projects, FortisBC would encourage a competitive funding award process and additional third party engagement.	Funding is largely allocated through a competitive process. For each potential project, Network Operators or third parties submit a project outline during an initial screening process to Ofgem, who then decides which projects will advance to the full submission stage (with advice from an independent panel of experts).

77.4 Please compare the benefits and risks to the utility and to ratepayers of FortisBC's proposed Innovation Fund versus the RIIO Framework innovation stimulus.

1 **Response:**

Item - Risks	Innovation Fund - FortisBC	RIIO - Ofgem
Lack of thorough review of projects	FortisBC's proposed Innovation Fund has three stages to develop projects which include extensive identification, evaluation, selection and execution. FortisBC has two separate bodies of oversight which includes an Innovation Working Group and an Executive Steering Committee, both are made up of FortisBC technical experts and executives to oversee the allocation of funds and project plans.	If companies have well-developed business plans, the application could be fast tracked. However, even fast-tracked companies have to undergo consultation with stakeholders before implementing projects.[88]
Insufficient consultation with outside stakeholders	Innovation Fund at FortisBC has an External Advisory Panel made up of stakeholders to provide insight and feedback on the companies' innovative initiatives on a periodic basis	If a company is fast tracked and can move on to the next step, consultation will still be required by stakeholders.
Potential stranded assets from new technology	Some of the projects that the Innovation Fund include RNG and Hydrogen which require extensive funding and can be utilized in our existing network. The Fund aims to minimize the likelihood of underutilization of the energy system by developing technologies that can utilize FortisBC's system to achieve decarbonization goals.	Companies will need to identify areas in RIIO model where work might be required to maintain their assets
Failed projects resulting in little advancement	Earlier stages of innovation cycles are speculative in nature and yield uncertain commercial returns, failures in terms of innovation attempts can help provide useful information for further research.	While not all projects will be successful, their costs will be fully analyzed by Ofgem and external committees [89]

[88] https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbookpdf.
[89] https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbookpdf

Item - Risks	Innovation Fund - FortisBC	RIIO - Ofgem
Potential customer interruptions or energy not supplied to customers	Projects will be explored on an experimentation basis and if disruption to customer energy services is required, it will be limited to small areas.	In the RIIO framework, companies are responsible for planning and managing operational risk. Managing this risk could mean that even if the company will incur higher costs in current periods, it can potentially mean that future costs will be reduced.
Encourages research in clean energy projects to lower GHG emissions	The Fund will assist FortisBC in addressing the expectation to reduce emissions and support transition to a lower carbon economy	RIIO Model is designed to encourage network companies to seek out innovative ways to come up with projects that have a positive impact
De-risk investments	In a risk averse industry, the Innovation Fund provides a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers.	De-risks investments for both customers and shareholders and helps establish business case for full-scale technology development and market adoption
Rewards good companies, punishes bad companies	This Fund only applies to FortisBC.	Poorly performing or inefficient utilities in RIIO could see rates of return below the cost of debt. This incents utilities to provide good information, deliver the outputs promised and provide customer service. Also rewards companies by decreasing regulatory burden. [90]
Helps meet customer demands and respond to needs of future customers	There are direct benefits to consumers that include improving the way they use their energy, control their energy use and derive benefit from it.	Secondary deliverables for companies include revising their approach if needed to reflect technological or political development while keep costs low for customers
Encourages cost of energy to be affordable	As energy demand and consumption is rising, more investment into innovation is required to keep costs affordable for customers	As energy demand and consumption is rising, more investment into innovation is required to keep costs affordable for customers[91]

[90] https://core.ac.uk/download/pdf/46713473.pdf

[91] https://ceadvisors.com/wp-content/uploads/2018/05/Concentric-Final-Innovation-Report-4.23.18.pdf

Item - Risks	Innovation Fund - FortisBC	RIIO - Ofgem
Provides low-risk experimentation	In a highly risk averse industry, the Innovation Fund provides a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers.	Costs spread out over transmission and distribution customers and investors which allows utilities to experiment in a low-risk environment. Investors and consumers will also share the benefits if companies deliver outputs for less money.
Incents utilities to be more transparent	FortisBC will be accountable to the BCUC in its administration and oversight of the Fund.	Companies will develop well-justified business plans, provide any requested data which will be scrutinized by Ofgem and external stakeholder committees. [92]
Decreases regulatory burden	Utilities like FortisBC need a flexible and distinct program for resourcing innovation to support the reduction in customer GHG emissions in a cost-effective manner	Speeds up regulatory process and frees time for utilities to spend more time running their business and continuing to improve outputs.
Increased focus on stakeholder engagement	Innovation Fund at FortisBC has an External Advisory Panel made up of stakeholders to provide insight and feedback on the companies' innovative initiatives on a periodic basis.	Engagement with stakeholders for proposed projects needs to be done along with engagement that is already being done on an ongoing basis. This is included in the RIIO objectives. [93]
Encourages companies to take leading role in sustainable energy sector	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	Companies will be proactive in seeking the best way to provide sustainable network services for the long term, be open minded about how best to deliver and innovate to achieve desired outcomes
Risk Assessments required to manage potential risk	As projects will be extensively reviewed by an external advisory panel, executive steering committee and technical working group, risk will also be one of the criteria assessed in evaluations.	Under RIIO framework, an assessment is required of potential risks in projects.

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2

[92] https://ceadvisors.com/wp-content/uploads/2018/05/Concentric-Final-Innovation-Report-4.23.18.pdf
[93] https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbookpdf

On page 16 of Appendix C6-1, Concentric states the following in the Innovation Report:

> In 2000, the NYPSC approved a surcharge intended to fund medium-to-long-term R&D by New York's investor-owned natural gas local distribution companies (LDCs) in response to a decision by the Federal Energy Regulatory Commission to phase out support for the Gas Research Institute through a surcharge on interstate pipeline deliveries. New York's LDCs pledged to work collaboratively to address common needs and avoid duplication of research activities. The NYPSC relied on a Staff recommendation to have funds directed to distribution activities, and not to upstream activities (i.e., supply and storage) or to improving end-use appliances that were considered competitive activities. <u>This effort came to be known as the Millennium Fund</u>. [*Emphasis added*]

77.5 Please provide the same analysis as was provided in response to IRs 77.1 through 77.4 above to compare the proposed Innovation Fund with New York's Millennium Fund.

Response:

The state of New York is served by six large investor owned utilities (central Hudson, ConEdison, National Grid, NYSEG, RG&E and Orange and Rockland), one large municipal utility (LIPA), and many smaller utilities. Consolidated Edison, or ConEd, is geographically the smallest of the investor owned utilities in New York, but it serves the largest number of customers (ConEd provides service to the city of New York).

One important difference between New York and BC electric utilities relates to generation assets. While FBC and BC Hydro are vertically integrated utilities with sizable generation assets in the rate base, virtually all New York utilities' generation assets were divested as part of the electricity industry restructuring. The incumbent power distributors, however, have retained the provider-of-last-resort obligation, and are procuring the power to meet this obligation through bilateral wholesale contracts with competitive suppliers. Most of the utilities physically purchase the majority of their required energy on the New York Independent System Operator (NYISO) Day-ahead market. NYISO is a non-profit organization responsible for managing New York's electric grid and its competitive wholesale electric marketplace. On the other hand similar to FEI, New York's gas distribution companies have no interest in gas commodity business; however, all of the gas companies continue to sell gas to those customers (with no mark-up) who choose to buy gas from utilities.

Another important difference between New York and BC relates to the role and function of New York State Energy Research and Development Authority (NYSERDA). NYSERDA is a public-benefit corporation with the mission to advance innovative energy solutions in ways that

improve New York State's economy and environment. Some of NYSERDA main objectives include increasing state's energy efficiency and conservation, growing the renewable and diverse energy supplies and protecting the environment. Since 1996, NYSERDA's budget is funded by ratepayers through System Benefit charge (SBC) program. The SBC is collected by investor-owned utilities from gas and electric customers in the State, and funds the majority of NYSERDA's programs. In contrast, such an organization does not exist in BC and most of the energy efficiency and conservation efforts, as well as other innovative solutions to decarbonize the BC economy, are managed by the utilities.

The structure of innovation funding in New York, through the Millennium Fund, displays similarities to FortisBC's Innovation Fund. The Millennium Fund provides funding for medium-to-long-term R&D projects conducted by New York's investor-owned natural gas utility companies. The regulator has mandated that funds must be limited to R&D for certain distribution activities and that funds must be allocated 80/20 to co-funded and internal R&D projects. However, the administration and management of the Millennium Fund is left largely under the jurisdiction of New York's investor-owned utilities to provide them with the flexibility required to incorporate R&D projects into their unique business circumstances. In comparison, FortisBC's Innovation Fund would be administered by the FortisBC Companies' for innovation projects at all stages of the value chain to maximize the utilization of its natural gas assets in an evolving climate policy context. Innovation funding would be centrally managed by FortisBC, allowing for greater coordination and efficient execution of project implementation.

Task Item	British Columbia	New York
Key Climate Policy Mandates	• 80% GHG Reductions from 2007 Levels by 2050 (provincial) • DSM Regulation (provincial)- Public Utilities must include demand side measures that assist low-income households in reducing energy consumption, improve energy efficiency in rental properties, establish an education program and local communities in adopting more stringent building codes. • 15% Renewable Gas Content Requirement for Industrial and Consumer end-use applications (provincial) • BC Energy Step Code (Provincial) • Clean Fuel Stand (Federal)- Increase the use of lower carbon fuels, energy sources and technologies. • Climate Change Accountability Act (Provincial)-GHG Reductions 40 per cent below 2007 levels by 2030, 60 per cent by 2040, and 80 per cent by 2050 • Carbon tax (Provincial)- $40/ton CO2e	• 40% GHG reductions from 1990 levels by 2030. 80% GHG reductions by 2050. • REV - Under the REV Order, utilities can increase revenues earned from serving as the distributed systems platform (DSP) provider under market-based earnings (MBE) • 70% of consumed electricity must come from renewable sources by 2030. • Proposal to mandate 100% clean electricity by 2040 • All new residential and commercial buildings must meet energy efficiency standards found in the 2015 International Energy Conservation Code. • 600 trillion btu (175.8 TWh) increase in statewide energy efficiency (at source) by 2030. • $3 billion for Renewable Energy and Clean Transportation in the Green Future Fund for renewable energy and clean transportation. • Regional Greenhouse Gas Initiative (RGGI)- 9 north-eastern states (including New York) operate under a regional cap and trade carbon pricing system. Approx. price of USD $5/ton CO2e.
Mandate of the Utility Regulator	• Protects consumers and ensures prices are fair. • Ensures utilities have the opportunity to get reasonable returns. • Delivers Government programs.[94]	• To ensure affordable, safe, secure, and reliable access to electric, gas, steam, telecommunications, and water services for New York State's residential and business consumers, while protecting the natural environment. • The Department also seeks to stimulate effective competitive markets that benefit New York consumers through strategic investments, as well as product and service innovations.[95]

[94] https://www.bcuc.com/about/who-we-are.html

[95] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/F2B657511FFEAED885257687006F3A95/$FILE/2017-18_annual_report_2018_08_07.final.pdf

Task Item	British Columbia	New York
Number of Licensed Gas & Electric Utilities	Electric: 1 crown-owned utility, 4 investor-owned utilities, multiple small-scale municipal-owned utilities. Gas: 2 leading investor-owned utilities, multiple small scale investor-owned and municipal-owned utilities.[96]	Electric & Gas: 6 investor-owned utilities, 1 large municipal-owned utility, many smaller utilities.[97]
Number of Electric Customers	Approximately 170,000 (FortisBC)	Unknown
Annual Electricity Delivered	3.3 TWh per annum (FortisBC)	143.2 TWh per annum
Number of Gas Customers	Approximately 1 million (Fortis Energy Inc.)	Unknown
Annual Gas Delivered	200+ PJs per annum (Fortis Energy Inc.)	1371 PJs per annum

In terms of regulatory environment and as indicated in table below, New York' and FortisBC' regulatory environment are comparable.

Item	FortisBC	Typical New York Utility
Test year	Use of forecast test years	Use of fully-forecasted test year
Rate making approach	Periodic indexed or forecast 5 year MRPs for revenue requirement determination with earning sharing mechanisms	3 year forecast MRPs with earnings sharing
Revenue decoupling	The utilities' revenue is decoupled from costs. The Companies' are protected from demand variation risk.	Full revenue decoupling offsets the effect on earnings of variations in sale for any reason
Incremental Capital	Treatment of major capital expenditures not funded through MRP outside the incentive framework	Utilities may implement riders to recover carrying costs on incremental expenditures associated with projects such as replacement of leak prone pipe
Deferral accounts	Use of deferral accounting for items such as taxes, pension and OPEB, debt expense and other non-controllable costs. History of using deferral accounts for rate smoothing purposes	Deferral accounting for items such as pension and OPEB, property taxes, debt costs, and major storm cost reserves. New York has a history of using deferral accounts for rate smoothing purposes

[96] https://www.bcuc.com/consumers/consumer-information.html
[97] https://power2switch.com/NY/

Item	FortisBC	Typical New York Utility
Stranded assets	Utilities have been historically able to recover the prudently incurred costs of their undepreciated costs	Utilities have been historically able to recover the prudently incurred costs of their undepreciated costs
Commodity price risk	Utilities are protected from commodity price risks through adjustment clauses.	Distributors are fully divested and protected from commodity risk. Adjustment clauses allow the utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier.

1

Item	FortisBC Innovation Fund	The Millennium Fund
Method of collecting funds from the consumer	Funding for FortisBC's stimulus would be collected through a basic charge rider. This would apply equally to customers across the gas network ($0.40/month) and the FBC electric service territory ($0.30/month)	Ratepayer funded surcharge, at a maximum rate of $0.0174/dth ($0.0165/GJ) through 2004. Firm transportation and sales is the source of funding for the program. Since 2004, R&D funding is on a voluntary basis by any utility that wants to participate.
Who can access the funds and how the funds are managed	FortisBC Companies can access the funds with the potential to award funding to private sector organizations, the public sector or research institutions moving forward. Funds would be managed at FortisBC's discretion in collaboration with potential partner organizations.	New York's investor owned natural gas utilities can access the funds in coordination with various public sector organizations and R&D entities. Funds are managed at the discretion of the utilities. New York's gas utilities have pledged to work collaboratively to guard against research duplication.
How the funds are administered and managed	The fund would be administered by the FortisBC Companies. It would be internally managed by an Executive Steering Committee and an Innovation Working Group with sector-specific experts from the gas and electric divisions. The fund would receive feedback from an External Advisory Council to ensure alignment with the fund's guiding principles and objectives.	Millennium Fund money is spent at the utilities' discretion. Funds must be allocated 80/20 to co-funded and internal R&D projects, respectively, to ensure funds are directed to the area of most need while also allowing utilities the discretion to fund R&D work particular to their unique business circumstances.

Item	FortisBC Innovation Fund	The Millennium Fund
Selection Criteria for Projects to be Funded	The fund applies to innovation projects at all stages of the value chain to maximize the utilization of FortisBC's natural gas and electric assets in an evolving climate policy context. Criteria for consideration would include GHG reduction potential, impact on ratepayers, technological readiness, additional third party funding availability as well as the number of potential partner organizations.	Medium-to-long-term R&D projects (activities that are at least 2- years removed from becoming commercial products) conducted by New York's investor-owned natural gas utility companies. Qualifying distribution activities for the fund includes pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. Activities that do not qualify include upstream activities such as supply and storage, and improvements to end-use appliances that are considered competitive activities. This position on end-use activities is considered an outlier compared to similar innovation frameworks established by comparable energy regulators.
Competitiveness of the Funding Award Process	FortisBC's fund would be initially allocated to the FortisBC companies, with the potential to award funding to, or partner with, private sector organizations, the public sector or research institutions moving forward. Dependent on the quality and number of partner organizations for potential projects, FortisBC would encourage a competitive funding award process and collaborative third party engagement.	Funding is open to all of New York's investor-owned local gas distribution utilities. Third party engagement on eligible projects can occur between local gas distribution utilities and organizations such as NYSEARCH, OTD, GTI or other research providers. A high level of collaboration is encouraged through the Millennium Fund.

1

Risks	FortisBC Innovation Fund	Millennium Fund
Stage of Innovation Cycle	The fund applies to innovation projects at all stages of the value chain to maximize the utilization of FortisBC's natural gas and electric assets in an evolving climate policy context. Inclusion of various components of the value chain reduces risk and spreads existing risk across various stages of the innovation cycle.	Long-term R&D projects, at least 2 years from commercialization, face potentially higher risk and higher cost implications in comparison to R&D that is closer to commercialization. The cost-benefit analysis that regulators typically apply to more traditional utility investments may not apply to long-term R&D.
Insufficient external stakeholder	Innovation Fund at FortisBC has an External Advisory Panel made up of stakeholders to provide insight and feedback on the companies' innovative	Third party engagement with public sector agencies and research institutions works to mitigate risk of insufficient stakeholder

Risks	FortisBC Innovation Fund	Millennium Fund
consultation	initiatives on a periodic basis.	consultation.
Potential stranded assets from new technology	Some of the projects that the Innovation Fund include RNG and Hydrogen which require extensive funding. These sources of energy will ensure that existing assets are utilized as stranded assets is a great risk to FortisBC as a company as well.	Funding emphasis on distribution activities such as pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. This helps de-risk concern over stranded assets for New York's local investor-owned gas utilities.
Potential customer interruptions or energy not supplied to customers	Projects will be explored on an experimentation basis and if disruption to customer energy services is required, it will be limited to small areas.	Utilities are responsible for managing operational risk. Managing this risk could mean that even if the company will incur higher costs in current periods, it can potentially mean that future costs will be reduced.

1

Benefits	FortisBC Innovation Fund	Millennium Fund
Encourages research in clean energy projects to lower GHG emissions	The Fund will assist FortisBC in addressing the expectation to reduce emissions and support transition to a lower carbon economy.	Provides additional R&D funding to explore long-term innovative solutions while encouraging utility collaboration and consideration to unique business circumstances.
Encourages cost of energy to be affordable	Up-front R&D investments help ensure long-term energy costs remain affordable for customers.	Up-front R&D investments help ensure long term energy costs remain affordable for customers.
Provides low-risk experimentation	In a highly risk averse industry, the Innovation Fund provides a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers.	Costs spread out over investor-owned utility distribution customers and investors allows for low-risk experimentation. Investors and consumers will also share the benefits if companies deliver outputs for less money.
Encourages companies to take leading role in sustainable energy sector	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.	Companies will be proactive in seeking the best way to provide sustainable energy services for the long term. Mid-to-Long term R&D fosters innovative measures to achieve desired outcomes.

2

3

On pages C-136 –C-137 of the Application, FortisBC states the following:

> In late 2017, Union Gas Limited, in its 2018 Cap and Trade Compliance Plan proposed a Low Carbon Initiative Fund (LCIF)…
>
> 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)…
>
> Union Gas proposed that the cost of the LCIF be recovered from customers as customers would benefit from the innovative technologies pursued… However, the cancellation of the Ontario Cap and Trade program in 2018 by the provincial government led to the suspension of the Ontario Energy 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.

77.6 Please provide the same analysis as was provided in response to IRs 77.1 through 77.4 above to compare the proposed Innovation Fund with the LCIF.

Response:

a. Comparison of natural gas and electric utility industry in BC and Ontario

Task Item	British Columbia	Ontario

Task Item	British Columbia	Ontario
Key Climate Policy Mandates	• 80% GHG Reductions from 2007 Levels by 2050 (provincial) • DSM Regulation (provincial)- Public Utilities must include demand side measures that assist low-income households in reducing energy consumption, improve energy efficiency in rental properties, establish an education program and local communities in adopting more stringent building codes. • 15% Renewable Gas Content Requirement for Industrial and Consumer end-use applications (provincial) • BC Energy Step Code (Provincial) • Clean Fuel Stand (Federal)- Increase the use of lower carbon fuels, energy sources and technologies. • Carbon tax (Provincial)- $40/ton CO2e • Climate Change Accountability Act (Provincial)-GHG Reductions 40 per cent below 2007 levels by 2030, 60 per cent by 2040, and 80 per cent by 2050	• Reduce emissions by 30% below 2005 levels by 2030 • Ontario Carbon Fund – This is an emissions reduction fund to encourage private investment in clean technology solutions. Funding of over $400 million • Ontario Reverse Auction ($50 million) allowing bidders to send proposals for emissions reduction projects to compete for contracts • Looking into incorporating Renewable Fuel Standard for gasoline, will lead to 5% reduction in GHG by 2020 • Planning on providing funding provided for fuel distributors for high-blend sustainable biofuels and infrastructure upgrades • Planning on piloting waste and agricultural methane as a fuel source • Electric Vehicle purchasing incentive • Electric and Hydrogen Advancement program – vehicle manufactures must participate • Low Carbon Innovation Fund[98]
Mandate of the Utility Regulator	• Protects consumers and ensures prices are fair • Ensures utilities have the opportunity to get reasonable returns • Promotes sustainability • Delivers Government programs	• Establish rates and prices that are reasonable to consumers and that allow utilities to invest in the system • Encourage higher performance from natural gas and electricity utilities and measuring progress • Making the customer's own usage easier to understand • Looking out for customer interests, investigating complaints and applying penalties • Thinking about long-term needs of energy sector[99]

[98] https://www.ontario.ca/page/climate-change
[99] https://www.oeb.ca/about-us/mission-and-mandate

Task Item	British Columbia	Ontario
Number of Licensed Electric Utilities	1 crown-owned utility, 4 investor-owned utilities, multiple small scale municipal-owned utilities	30-40 licensed electric utilities[100]
Number of Electric Customers	Approximately 170,000 (FortisBC)	Approximately 5.6 million[101]
Annual Electricity Delivered	3.3 TWh per annum (FortisBC)	About 137.4 TWh: - 60% nuclear - 25% Hydro - 6% gas/oil - 7% wind[102]
Number of Licensed Gas Utilities	2 leading investor-owned utilities	3 licensed gas utilities[103]
Number of Gas Customers	Approximately 1 million (Fortis Energy Inc.)	Approximately 3.7 million[104]
Annual Gas Delivered	200+ PJs per annum (Fortis Energy Inc.)	500+ PJ per year [105]

b. Detailed comparison of the regulatory environment in BC versus Ontario. Compares OEB and BCUC.

Item	BCUC – British Columbia	OEB - Ontario
Are energy markets privatized – can consumers choose their energy providers?	There are two major energy providers, BC Hydro and FortisBC	2 gas licensed utilities: Enbridge + Union Gas and EPCOR 30-40 licensed electricity utilities. Consumers are assigned providers based on where they live. [106]

[100] https://www.oeb.ca/industry/licensed-companies-and-licensing-information.
[101] Number obtained from emailing OEB.
[102] http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.
[103] https://www.oeb.ca/industry/licensed-companies-and-licensing-information.
[104] https://www.uniongas.com/about-us/company-overview.
[105] Data obtained from emailing OEB.
[106] https://www.oeb.ca/industry/licensed-companies-and-licensing-information.

Item	BCUC – British Columbia	OEB - Ontario
Who do the regulators oversee?	Area of oversight include: Natural Gas utilities, Electricity Utilities, Intra-provincial Pipelines, Universal compulsory automobile insurance.[107]	The Ontario Energy Board regulates Ontario's energy sector. We ensure that natural gas and electricity companies follow the rules.[108]
What is the role and mandate of the regulator?	The BCUC's mission is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. [109]	The OEB is an independent regulatory body that makes decisions and provides advice to the government in order to contribute to a sustainable, reliable energy sector and help consumers get value from their natural gas and electricity services. [110]
How do the regulators engage stakeholders?	Most applications are considered through open public hearings and the public has an opportunity to participate in the hearings. [i]	Engage using committees, consumer panels, sector forums and advisory roundtables. [111]
How is the regulator funded?	The BCUC has been self-funded since 1988. Its costs are recovered primarily through a levy on the businesses it regulates. [112]	Funded through licensing fees. All companies have to pay a fee.[113]
Is there a complaint process for stakeholders?	The BCUC receives complaints and inquiries about regulated energy utilities, as well as complaints regarding ICBC's basic automobile insurance rates.[114]	Customers can submit complaints about an energy retailer to the OEB. [115]

[107] https://www.bcuc.com/about/our-role.html.
[108] https://www.oeb.ca/about-us/mission-and-mandate/ontarios-energy-sector.
[109] https://www.bcuc.com/about/who-we-are.html.
[110] https://www.oeb.ca/about-us/mission-and-mandate.
[111] https://www.oeb.ca/about-us/who-we-are/stakeholder-and-consumer-groups.
[112] https://www.bcuc.com/about/.
[113] Information received by phone from the OEB.
[114] https://www.bcuc.com/consumers/utility-icbc-complaint-process.html.
[115] https://www.oeb.ca/consumer-protection/make-complaint.

Item	BCUC – British Columbia	OEB - Ontario
Who governs the regulator?	Governed by Utilities Commission Act [116]	Mandate and authority comes from the Ontario Energy Board Act, 1998, the Electricity Act 1998 and a number of other provincial statutes including: the Energy Consumer Protection Act 2012, The Municipal Franchise Act, the Oil, Gas and Salt Resources Act, and the Toronto District Heating Act. [117]
What kind of judicial powers, if any, does the regulator have?	Quasi-judicial entity. Can issue administrative penalties and investigate companies.[118]	Issues rules and codes that energy companies must follow, also provides general guidelines.
What kind of sustainability initiatives does the regulator promote?	BCUC invites comments on projects from many different environmental organizations and also follows the energy objectives outlined in the Clean Energy Act and applies them to the utilities it regulates. BCUC is currently considering proposals for in-house sustainability funds like the Innovation Fund. [119]	OEB developed the regulatory framework to support Ontario's cap and trade program. It requires natural gas utilities to develop plans to support the government's policy of reducing GHG emissions. [120]

[i] https://www.bcuc.com/get-involved/understanding-process.html.

c. Comparison of FortisBC Clean Growth Innovation Fund and LCIF Fund

This comparison is based on the archived information that was provided from the Ontario government website for the Low Carbon Innovation Fund (LCIF) which states that the fund was part of a previous government and is no longer accepting submissions for funding. The LCIF was funded by proceeds from the province's carbon market, which under the new provincial government is no longer present.[121]

Item	FortisBC Innovation Fund	LCIF – Low Carbon Innovation Fund

[116] http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01#part1.
[117] https://www.oeb.ca/about-us/mission-and-mandate.
[118] https://www.bcuc.com/about/who-we-are.html.
[119] https://www.bcauditor.com/sites/default/files/publications/reports/FINAL_BCUC.pdf
[120] https://www.oeb.ca/about-us/energy-policy-initiatives
[121] https://www.ontario.ca/page/low-carbon-innovation-fund

Item	FortisBC Innovation Fund	LCIF – Low Carbon Innovation Fund
Method of collecting funds from the consumer	Funding for FortisBC's stimulus would be collected through a basic charge rider. This would apply equally to customers across the gas network ($0.40/month) and the FBC electric service territory ($0.30/month)	Was funded by proceeds from the province's carbon market.
Who can access the funds and how the funds are managed	FortisBC Companies can access the funds with the potential to award funding to private sector organizations, the public sector or research institutions moving forward. Funds would be managed at FortisBC's discretion in collaboration with potential partner organizations.	Companies and entrepreneurs with innovative clean tech solutions, publically assisted Ontario Universities, Ontario college of applied arts and technology.
How the funds are administered and managed	The fund would be administered by the FortisBC Companies. It would be internally managed by an Executive Steering Committee and an Innovation Working Group with sector-specific experts from the gas and electric divisions. The fund would receive feedback from an External Advisory Council to ensure alignment with the fund's guiding principles and objectives.	Successful applicants are provided funds from two funding streams. The Technology Validation Stream and the Technology Demonstration Streams.
Selection Criteria for Projects to be Funded	The fund applies to innovation projects at all stages of the value chain to maximize the utilization of FortisBC's natural gas and electric assets in an evolving climate policy context. Criteria for consideration would include GHG reduction potential, impact on ratepayers, technological readiness, additional third party funding availability as well as the number of potential partner organizations.	Projects that require funding must be done in Ontario, have the potential to help Ontario meet its GHG reduction goals as part of the Climate Change Action Plan, and be completed within two years. Also must be able to commercialize technology solution in Ontario.
Competitiveness of the Funding Award Process	FortisBC's fund would be initially allocated to the FortisBC companies, with the potential to award funding to private sector organizations, the public sector or research institutions moving forward. Dependent on the quality and number of partner organizations for potential projects, FortisBC would encourage a competitive funding award process and collaborative third party engagement.	Competitive, distributed on an application basis to successful applicants.

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2 d. Compare risks and benefits to the utility and to ratepayers of FortisBC's proposed innovation
3 Fund versus LCIF Fund

Item - Risks	Innovation Fund - FortisBC	LCIF – Ontario[122]
Lack of thorough review of projects	FortisBC's proposed Innovation Fund has three stages to develop projects which include extensive identification, evaluation, selection and execution. FortisBC has two separate bodies of oversight which includes an Innovation Working Group and an Executive Steering Committee, both are made up of FortisBC technical experts and executives to oversee the allocation of funds and project plans.	All projects had strict guidelines in that they must be done in Ontario, have the potential to reduce GHG emissions as part of the climate Action Plan and must be completed within two years.
Failed projects resulting in little advancement	Earlier stages of innovation cycles are speculative in nature and yield uncertain commercial returns, failures in terms of innovation attempts can help provide useful information for further research.	LCIF Funding was provided for projects that had a proven technology application that had already been successful in a different sector/industry, but is unproven in the proposed application.
Encourages research in clean energy projects to lower GHG emissions	The Fund will assist FortisBC in addressing the expectation to reduce emissions and support transition to a lower carbon economy	LCIF was provide to help researchers, entrepreneurs and companies create and commercialize new, globally competitive, low carbon technologies that would help Ontario meet its GHG emissions reductions target.
Provides low-risk experimentation	In a risk averse industry, the Innovation Fund provides a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers.	All companies and entrepreneurs applying for funding must have funding commitments from other sources other than the Government of Ontario to de-risk investment.
Encourages companies to take leading role in sustainable energy sector	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	All projects must have the potential to help Ontario meet its GHG reductions goals as part of the Climate Change Action Plan. Only companies that would be working towards this goal would be applying for this fund.

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[122] https://www.ontario.ca/page/low-carbon-innovation-fund#section-4

78.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.5, pp. C-142, C-144 – C-145

Governance Structure

On page C-142 of the Application, FortisBC states: "The Companies will be accountable to the BCUC in its administration and oversight of the Fund."

On pages C-144 – C-145, FortisBC states the following:

> 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…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. [*Emphasis added*]

On page C-145 of the Application, FortisBC states the following:

> 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. [*Emphasis added*]

78.1 Please confirm, or explain otherwise, that the two bodies – the Group and the Committee – managing and overseeing the Innovation Fund are composed solely of FortisBC employees.

Response:

Confirmed.

78.2 Please provide details of the envisioned process and the role of each governance body in the Innovation Fund administration, management and accountability, including:

- Financial tracking of funds received and spent;
- Project proposal preparation;
- Project selection and fund disbursements;
- Project progress reporting;
- Project targets achievement evaluation; and
- Project halting and financing reallocations.

Response:

While not finalized and subject to change based on direction received from the BCUC, FortisBC provides below a description of the process and role of each governance body of the Innovation Fund with regard to the listed activities.

Stage 1 – Project Identification

FortisBC will become aware of potential funding opportunities in several ways, including:

- Proactively, through Call for Proposal
- Reactively, by becoming aware of potentially relevant innovation projects during the regular course of business:
  - Meetings with other Fortis utilities
  - External Advisory Council meetings
  - Industry events
  - Meetings with industry associations, technology vendors, academic institutions
  - Discussions with other utilities

Stage 2 – Project Selection

On a regular basis, Working Group meetings will be held to review new innovation projects to be included in the overall Innovation Fund portfolio. New innovation projects will not generally be reviewed individually, but as a group in a sub-portfolio. The same sub-portfolio will be reviewed with the External Advisory Council prior to a final investment decision being made as to which (if any) projects within the sub-portfolio will be approved for funding. Between two and four sub-portfolios are envisioned in any particular calendar year.

Individual project budgets, timelines and milestones for approved innovation projects will be identified at this stage.

Stage 3 – Project Management

On a regular basis, the Working Group will meet to review the progress and approve fund releases for all approved and active Innovation Fund projects.

Fund releases will be based on project proponents meeting:

- Pre-funding conditions
- Milestone events

In addition, the Working Group can:

- Approve new milestones and related funding amounts
- Cancel funding for projects
- Close completed projects

With respect to the specific activities identified in the question:

<u>Financial tracking of funds received and spent</u>

- This is the responsibility of the Working Group.

<u>Project proposal preparation</u>

- The Working Group will oversee the preparation of any Call for Proposal documents.

<u>Project selection and fund disbursements</u>

- The Working Group will do this in compliance with the strategic direction established by the Executive Steering Committee and will consider the feedback provided by the External Advisory Council.

<u>Project progress reporting</u>

- This is the responsibility of the Working Group.

<u>Project targets achievement evaluation</u>

- This is the responsibility of the Working Group.

Project halting and financing reallocations

- The Working Group will do this in compliance with the strategic direction established by the Executive Steering Committee and will consider the feedback provided by the External Advisory Council.

78.3 Please provide a high level estimate of the annual costs of the two governance bodies and provide this amount as a percentage of the overall Innovation Fund annual budget. Please explain how FortisBC proposes to recover these costs.

Response:

FortisBC expects to incur minimal incremental expenses to operate the governance bodies. When also considering costs for the External Advisory Council, annual amounts for meetings and related travel and support costs are expected to total less than $100 thousand (1.8 percent of total expenditures) across both FEI and FBC funds. These costs are included in the total funding and recovered by the proposed rate rider.

78.4 Please discuss the role of the External Advisory Council, if any, in the decision-making regarding the management and administration of the Innovation Fund.

Response:

FortisBC expects that the External Advisory Council to make recommendations which will be considered by the Working Group when making investment decisions.

78.4.1 Please discuss FortisBC's process for establishing the External Advisory Council.

Response:

FortisBC intends to canvas intervener groups for representation. In addition, FortisBC would like to have representation from academia and industry groups. A specific process for

contacting and selecting representatives will be established pending approval of the Innovation Fund.

78.4.2 Please provide an estimate of the annual costs for the External Advisory Council and provide this amount as a percentage of the overall Innovation Fund annual budget. Please explain how FortisBC proposes to recover these costs.

Response:

Travel and related meeting costs for the External Advisory Council are included as part of the funds established for governance activities. Please refer to the response to BCUC IR 1.78.3.

78.5 Please discuss whether any other costs, aside from the three governance bodies described above, will be incurred. If yes, please provide the amount of these annual costs and how FortisBC proposes to recover these costs.

Response:

FortisBC does not expect any other governance process costs aside from those described in the response to BCUC IR 1.78.3.

78.6 Please explain how FEI and FBC will report to the BCUC regarding the administration and oversight of the Innovation Fund.

Response:

FEI and FBC plan to report on administration and oversight of the Clean Growth Innovation Fund at the Annual Reviews.

79.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.6, pp. C-145 – C-146; FBC 2017 COSA and RDA Decision dated February 25, 2019, pp. 21, 3; BC Hydro 2015 RDA Decision dated January 20, 2017; Corix UBC NDES CPCN proceeding, Exhibit B-1-1, p. 2, Corix UBC NDES CPCN Decision dated December 12, 2014, pp. 30–32; Creative Energy NEFC CPCN proceeding, Exhibit B-1, pp. 75–75, Creative Energy NEFC CPCN Decision dated December 8, 2015, pp. 40–44

Accounting and Regulatory Treatment

On page C-145 of the Application, FortisBC states the following:

> FortisBC proposes customer RD&D funding annually that is expected to generate approximately $4.9 million for FEI and approximately $0.5 million for FBC…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…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.

79.1 Please explain, and provide supporting examples where applicable, if FEI and/or FBC have previously received BCUC-approval of the type of funding approach proposed for the Innovation Fund. Specifically, please explain if FEI and/or FBC have previously been approved to pre-collect amounts from ratepayers and record these amounts in a deferral account in advance of any costs being incurred and in advance of the specific purpose for the costs being identified.

Response:

FEI and FBC would not characterize the Clean Growth Innovation Fund request as a pre-collection in advance of costs being incurred, but rather as a mechanism designed to more closely match the collection of funds against the costs as they are incurred. FEI and FBC expect to incur the Innovation Fund costs over the term of the proposed MRPs and have identified the purpose of Clean Growth Innovation Fund in Section C6 of the Application and the main activities in Appendix C6-4. FortisBC's proposed approach is essentially the same as the normal process to forecast and recover of the Utilities' revenue requirement. Many other items are accounted for in deferral accounts and use rate riders, and this is standard utility practice.

The costs embedded in the utilities' annual revenue requirements are forecasts for the upcoming (test) year. Customer rates are set based on the forecast of these costs[123] and customers pay approved rates throughout the test year. The costs embedded in the test year revenue requirement and the recovery of those costs do not match as there are always timing differences between when the utilities receive revenue through rates and when expenditures occur. However, by setting rates based on test year forecasts, the matching of revenues and costs is as close as possible, thereby minimizing financing costs to customers for operating the utilities. From a timing of collection and expenditures perspective, the funding mechanism proposed for the Clean Growth Innovation Fund is no different, and the use of deferral accounts to address any timing issues is common. The use of rate riders is also a common industry practice. FEI has previously used rate riders for a number of purposes, including the current Revenue Stabilization Adjustment Mechanism (RSAM) and Biomethane variance rate riders.

Further, FEI and FBC would also not agree that funds are being collected in advance of the specific purpose for the costs being identified. The purpose is clear; it is only that specific initiatives have not been identified. Again, this is no different than having a funding envelope for O&M or for capital expenditures or for removal costs; the situation is not unique.

79.2 Please explain why it is not reasonable for FEI and FBC to utilize its current and commonly accepted cost recovery and deferral account approaches. Specifically, please explain why it would not be reasonable for FEI and FBC to seek approval of the Innovation Fund deferral account in this Application and to seek future approval for recovery of the balance in the deferral account through amortization of the deferral account.

Response:

When FortisBC requests approval of a deferral account in one application and then sets the recovery period in a later proceeding, it is usually due to the fact that, for many accounts, the amount of the costs are uncertain and the appropriate time period to match the costs to the benefits is also uncertain. Neither of these is true for the Clean Growth Innovation Fund.

FEI and FBC chose to seek approval for recovery of the balance through the rider mechanism in this Application, so that the rider amount can be applied equally to all customers upon approval, and remains constant for the MRP term.

[123] Among other things included in the revenue requirement such as revenue at existing rates.

79.2.1 As part of the above response, please discuss the pros and cons of the following approaches and, for each approach, please explain why such an approach would not be more appropriate than what is being proposed in this Application:

- Deferral account treatment similar to regulatory proceeding cost deferral accounts (e.g. FEI & FBC 2014-2019 PBR deferral accounts);
- Deferral account treatment similar to project development cost deferral accounts (e.g. FEI Transmission Integrity Management Capabilities CPCN Development Costs deferral account; FBC Preliminary and Investigative Charges deferral account);
- Deferral account treatment similar to DSM program spending (e.g. FEI EEC deferral account; FBC DSM deferral account).

Response:

Overall, the major issue FortisBC sees with all of the approaches listed is that they involve amortizing the deferral account balance, which results in recovery from customers according to their volumes (not all customers are treated the same). Other than that, the primary differences between the three deferral accounts listed are:

1. the time period of recovery; and
2. the first two deferral items discussed are for one-time costs, whereas both the DSM and the Clean Growth Innovation Fund are being set at a certain recovery amount for a period of time.

Deferral account treatment similar to regulatory proceeding cost deferral accounts (e.g. FEI & FBC 2014-2019 PBR deferral accounts).

These costs are usually incurred prior to the period that the application period covers (e.g., the majority of costs were incurred in 2013 for the FEI & FBC 2014-2019 PBR deferral accounts) and costs are amortized over the years covered by the application. This method is meant to match the recovery of the costs to the period to which the costs were applicable.

To adopt this method in terms of the timeframe of recovery of the innovation funding deferral, FEI/FBC would have to set a much longer recovery period for the account as the benefits would be expected to extend out for an unknown number of years. FEI/FBC do not believe a longer recovery period is required given the rate impacts over the five year total recovery period proposed, and extending the length of the deferral account recovery would result in a higher cost to customers.

Deferral account treatment similar to project development cost deferral accounts (e.g. FEI Transmission Integrity Management Capabilities CPCN Development Costs deferral account; FBC Preliminary and Investigative Charges deferral account).

These costs are usually incurred prior to the approval and decision to proceed with a capital project and the costs are amortized over a shorter time frame, usually in the one to three year range. This method is meant to ensure costs are recovered as soon as possible, without having a material rate impact on customers.

FEI/FBC are essentially adopting this timeframe for recovery of the innovation funding deferral account as they are recovering the costs from customers over one year. The only difference is that FEI/FBC are collecting the costs from customers in the same year the costs are incurred, rather than the following year.

Deferral account treatment similar to DSM program spending (e.g. FEI EEC deferral account; FBC DSM deferral account).

These costs are incurred on an annual basis and amortized over the following ten years. This method is meant to allocate the costs to the period of benefit of the DSM expenditures.

The pros and cons of this method are essentially the same as the regulatory proceeding cost method.

79.2.2 As part of the above response, please specifically explain why FortisBC considers it necessary to pre-collect funds through a rate-rider instead of utilizing its more standard approach for cost recovery.

Response:

Please refer to the responses to BCUC IRs 1.79.1 and 1.79.2.

In the FBC 2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA) Decision, the BCUC found overall that the method and results of FBC's 2017 COSA

Study reflect cost causation. The BCUC also made a number of determinations based on cost causality.[124]

In the British Columbia Hydro and Power Authority (BC Hydro) 2015 RDA Decision, the BCUC considered BC Hydro's study, rate design proposals, and proposals for its Electric Terms and Conditions. The BCUC made a number of findings based on principles of cost causation.[125]

Also in the BC Hydro 2015 RDA Decision, the BCUC considered the proposal for the Crisis Intervention Fund (later renamed the Customer Emergency Fund) and whether there was an economic or cost of service justification for this proposal, and the BCUC stated that "there can be some reasonably expected tangible benefits."[126]

79.3 Given the long-standing regulatory principles of cost causation, please discuss the regulatory justification for the proposed Innovation Fund for each of FEI and FBC.

Response:

The Companies Clean Growth Innovation Fund follows cost causation principles. The regulatory principles for cost causation not only include functionalization, classification and allocation of costs, but also direct assignment. When a cost is known to be caused by a certain customer group, directly assigning those costs to that group provides for the best allocation. As identified in Table C6-1 of the Application, the Clean Growth Innovation Fund spending will span the entire utility value chain and will provide cost-effective energy solutions to all customers. It is reasonable to expect that all customers will tangibly benefit from this work. Consequently, the mechanism by which FortisBC proposes to fund the Clean Growth Innovation Fund is fair and reasonable.

In the Corix Multi-Utility Services Inc. (Corix, CMUS) CPCN Application for Phase 1 of the Neighbourhood District Energy System at the University of British Columbia (Corix UBC NDES CPCN), Corix requested approval of a Carbon Emissions Rider, which it described as follows on page 2 of the application:

[124] FBC 2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA) Decision dated February 25, 2019, pp. 21, 35, 49.
[125] BC Hydro 2015 RDA Decision dated January 20, 2017, pp. 34-36.
[126] BC Hydro 2015 RDA Decision dated January 20, 2017, p. 97.

> It is proposed that during Phase 1, Corix will collect, in rates, a temporary rider called the Carbon Emissions Rider of $25 / tonne of GHG emissions. The rider is intended to ensure that initial customers served by temporary natural gas boilers contribute to the cost of future Alternate Energy Sources and to help mitigate potential changes in rates with the implementation of the Alternate Energy Sources. It is also intended to ensure that Corix has appropriate incentives to implement low carbon energy sources in the event natural gas prices stay low.[127]

In the Corix UBC NDES CPCN Decision, the BCUC found that the Carbon Emissions Rider (CER) did not satisfy the requirements of section 59 of the Utilities Commission Act (UCA). The BCUC rejected the CER and stated among things, the following:

> …the Panel has concerns about the appropriateness of pre-collecting what amounts to a contribution in aid of construction (CIAC). The Panel is not persuaded that sufficient need exists to require this pre-collection. There is no evidence that CMUS will be unable to completely fund the Phase 2 development, or that rates in Phase 2 will be so high that this CIAC is necessary…
>
> …Accordingly, the Commission Panel denies the inclusion of the Carbon Emissions Rider as part of CMUS' proposed rate design.[128]

79.4 Please provide a detailed comparison of FortisBC's Innovation Fund and rate rider requests with Corix's requested Carbon Emissions Rider.

Response:

FortisBC's proposed Clean Growth Innovation Fund and rate rider are not similar to Corix's requested Carbon Emissions Rider in any material aspect. The table below provides a detailed comparison between the two, showing that Corix's Carbon Emissions Rider is substantially different than FortisBC's proposal.

	FortisBC Innovation Funds and Rate Rider	Corix's Carbon Emissions Rider
Objective	To accelerate innovation of clean energy solutions in stages of pre-commercialization. The focus is providing cost effective, safe, and reliable solutions for FortisBC's customers while responding to climate policy aimed at GHG reductions	To pre-collect and offset the cost of future capital expenditures in UBC Neighbourhood District Energy System (NDES) Phase 2 for low-carbon alternative energy source.
Use of Funding	Funds to be collected and used during the proposed MRP term (2020 to 2024). Funding intended for	Funds were intended to be collected during UBC NDES Phase 1 (10 years from 2015 to 2024) but

[127] Corix UBC NDES CPCN proceeding, Exhibit B-1-1, p. 2.
[128] Corix UBC NDES CPCN Decision dated December 12, 2014, pp. 30-32.

	FortisBC Innovation Funds and Rate Rider	Corix's Carbon Emissions Rider
	research and development activities that aim to advance clean energy solutions from feasibility research stage to system testing, launch and operation stage as discussed in Section C6.4.3.4 of the Application. Please also refer to Appendix C6 for a list of specific activities that FortisBC intends to pursue with the funding. FortisBC does not expect to exceed the total funding level unless additional funding is approved by the BCUC. Furthermore, the funding is not meant for capital expenditures on currently commercially viable projects that would otherwise require separate BCUC approval. If, through research and development activities administrated under the Innovation Fund, pre-commercial technologies become technically and commercial viable as well as acceptable to FortisBC's customers and stakeholders in terms of cost effectiveness, safety, and reliability, FortisBC will seek approval for future expenditures for implementation, if necessary and subject to regulatory requirements at that time.	were not to be used until Phase 2. However, as discussed in BCUC decision (C-11-14) for the Corix's 2014 UBC NDES CPCN Application, the scope of UBC NDES Phase 2 is not defined and there is uncertainty of how and when Phase 2 will proceed. Furthermore, as per Corix's response to BCUC IR 1.26.1, Corix would consider continuing to collect the Carbon Emissions Rider from its customers if Phase 2 is uneconomical to proceed in 2024. In the event that a low carbon Phase 2 project is not available or feasible, Corix stated in its application that it might use the funds collected under the Carbon Emissions Rider to purchase external carbon offsets. The panel expressed concern with the generational inequity caused by the pre-collection of funds to be spent 10 years or more into the future. The panel was also not persuaded that sufficient need existed to require a pre-collection of funds as there was also no evidence that Corix would be unable to completely fund Phase 2 or that rates would be so high that a CIAC would be necessary.
Funding Level	Predictable and relatively fixed at $4.9 million for FEI and $0.5 million for FBC over the proposed term of the MRPs (2020 to 2024). FortisBC will seek BCUC approval for any additional funding required.	Variable as Corix's Carbon Emissions Rider is collected at a rate of $25 per tonne of GHG emission embedded into Corix's proposed levelized rates as per of the fuel costs, forecasted to escalate at the annual CPI. Therefore, the total amount collected for Corix's Carbon Emissions Rider depends on the consumption level of its customers, annual CPI, and the timing of Phase 2 as discussed in the Use of Funding above.
Design of Rate Rider	Fixed basic charge rate rider and equal for all customers at $0.40 per month for gas customers and $0.30 per month for electric customers. FortisBC believes it is fair that all customers fund innovation activities equally since all customer types, not just higher volume users, will experience the benefits.	Volumetric based on amount of energy used by customers at a rate of $25 per tonne of GHG emission, embedded into Corix's proposed levelized rates in $ per MWh. It creates a price signal which high volume users will pay for the Phase 2 capital expenditure more than low volume users
Term	Fixed – Over the proposed MRP period (2020 to 2024).	Uncertain – Assumed 10 years from 2015 to 2024; however, as discussed in Use of Funding above, Corix might continue to collect the Carbon Emissions Rider if UBC NDES Phase 2 is uneconomical to proceed in 2024 or Corix has not decided to use the funds to purchase external

	FortisBC Innovation Funds and Rate Rider	Corix's Carbon Emissions Rider
		carbon offsets.
End of Term Balance Treatment	Funds collected from customers not invested will be returned to customers at the end of the proposed MRP term (i.e. 2024).	Funds will not return to customers if not used in Phase 2. The Carbon Emissions Rider might continue if Phase 2 is uneconomical to proceed in 2024 or Corix decides to use the funds to purchase external carbon offsets. If Phase 2 occurs in 2024, Corix proposed to apply the total balance of the Carbon Emissions Rider as Contribution in Aid of Construction (CIAC) and amortize the balance over the life of the Phase 2 capital asset.
Benefits to Local Communities	As shown with potential innovation activities in Appendix C6, the Innovation Funds will create opportunities for local communities as FortisBC intended to work with private organizations locally in BC if available and also engage research labs at UBC and UNBC.	No benefit to local communities. Corix will accumulate and hold the funds collected under the Carbon Emissions Rider until Phase 2 occurs or Corix decides to use the funds to purchase carbon offsets if Phase 2 does not occur in 2024.
Reporting	FortisBC will be accountable to the BCUC in its administration and oversight of the Fund. FortisBC will provide an annual update on the progress on approved projects as part of its Annual Review process. For transparency, the Fund will be recorded in a non-rate base deferral account over the proposed term of the MRP.	Uncertain – Corix has not indicated in its Application if the Fund collected under the Carbon Emission Rider will be recorded in rate base or non-rate base deferral account.

79.5 Please explain whether any of the issues/concerns identified by the BCUC in the Corix UBC NDES CPCN Decision are applicable to FortisBC's requested Innovation Fund and rate rider. If yes, please explain how FortisBC's proposals address the issues/concerns raised by the BCUC. If no, please explain why not.

Response:

The issues/concerns identified by the BCUC in the Corix UBC NDES CPCN Decision are not applicable to FortisBC's proposed Clean Growth Innovation Fund and rate rider. Fortis provides below its comments on the four questions or criteria on which the BCUC based its determination to reject Creative Energy's Carbon Emissions Rider in its Corix UBC NDES CPCN Decision (Order C-11-14).

1. Does collecting amounts in rates now, to finance a construction of a subsequent phase give rise to issues of intergenerational equity?

This question was relevant to Corix's Carbon Emissions Fund and rate rider because it was a pre-collection of capital intended to offset the costs of uncertain future capital expenditures. In contrast, FortisBC's proposed Innovation Fund is to be collected and used over the term of the MRPs (2020 to 2024). The results of the Innovation Fund may ultimately give rise to future capital investments, but the capital costs of such a project would be collected from customers once an asset is in service, unlike the case with Corix's Carbon Emissions Fund and rate rider.

2. Is it reasonable to recover in rates amounts to offset potential costs of a phase around which uncertainty exists?

This question is not applicable to FortisBC's Innovation Fund and rate rider as FortisBC's Innovation Fund will not fund future projects around which uncertainty exists. The purpose of the Innovation Fund is to accelerate research and development activities on clean energy solutions during the proposed term of the MRPs. Specific examples of research and development activities as well as pilot projects are discussed in Appendix C6 of the Application.

3. Is it fair to levy the CER only on early connectors to the NDES?

This question is not applicable to FortisBC's Innovation Fund and rate rider as FortisBC's Innovation Fund is not used for capital projects to which there are early or later connectors. The Innovation rate rider will be collected from FortisBC's customers over the proposed MRP term and the accumulated fund will be used for research and development activities that benefits FortisBC customers now and into the future. All customers will benefit from the research and development activities.

4. Is it fair to levy an emission rider on emissions generated by carbon which has already been taxed by the provincial government?

The Innovation Fund rate rider is a fixed basic charge rider and is equal to $0.40 per month for FEI customers and $0.30 per month for FBC customers, which is designed to fund specific research and development activities. The Innovation Fund rate rider is not a volumetric based rate rider and it does not tie to customers' volume or GHG emissions like Corix's proposed Carbon Emissions Rider. FortisBC's Innovation Fund rate rider does not create a price signal similar to a form of carbon tax such that higher volume users will pay more for innovation due to their energy requirements.

79.6 Please explain, with specific reference to sections 59 and 60 of the UCA, why the proposed Innovation Fund and rate rider are appropriate.

Response:

As explained in FortisBC's responses to BCUC IRs 1.79.4 and 1.79.5, FortisBC's proposed Clean Growth Innovation Fund and rate rider are not similar in any material respect to Corix's Carbon Emissions Rider noted in the preamble above. As such, there are no similar concerns related to whether FortisBC's proposal satisfies the requirements of section 59 to 60 of the *Utilities Commission Act.* As detailed in Section C6 and Appendix C6-1 and C6-2 of the Application, investments in innovation/research and development have been approved by regulators in other jurisdictions and the public interest rationale for doing so is compelling. Investment in innovation will provide direct and tangible benefits to FortisBC's customers and are an increasingly important part of FortisBC's business due to the need to improve environmental performance.

FortisBC's proposed Clean Growth Innovation Fund and rate rider are appropriate with reference to section 59 and 60 of the UCA as follows:

- Per section 59(1)(a) and 59(5) of *Utilities Commission Act*, the Innovation Fund and rate rider are just and a reasonable for reasons such as the following:
    - The Innovation Fund will provide a direct benefit to customers by improving how they use and benefit from FortisBC's energy products and accelerating the pace of clean energy innovation. Prioritizing the role of innovation as part of FortisBC's core business also has the potential to increase the future net benefits derived from these investments beyond the original investment capital. Investments of this kind are aimed at increasing the overall cost effectiveness, safety and reliability of the solutions FortisBC offers its customers.
    - The Innovation Fund provides a means of demonstrating to customers the viability of new technologies, with a mind to providing cleaner and more affordable energy sources for the future.
    - The Innovation Fund mitigates the risk of future rate increases.
    - The proposed rate rider is a fair and reasonable charge for the nature and quality of the service provided by the utility as it only recovers the cost of the investment. The investments will be made in accordance with sound principles, the central management of funds and a robust governance model, which has been designed to prioritize collaboration and strategic investment. Any funds collected through the rate rider which are not used during the MRP term period will be returned to customers.

- Per section 59(1)(b) and 59(4)(b), the Innovation Fund and rate rider are not unduly discriminatory or unduly preferential. Under the proposal, each customer pays the same contribution to the Innovation Fund as all customers will benefit from the results of the Innovation Fund. The rate rider proposed by FortisBC has been calculated so as to avoid disadvantaging customers by remaining stable and predictable throughout the proposed MRP term.
- Per section 60(b)(1)(iii), FortisBC's proposed Innovation Fund and rate rider encourages FortisBC to increase efficiency, reduce costs and enhance performance, by allowing FortisBC to invest in research and development opportunities that will increase efficiency, reduce costs and enhance performance for the benefit of FortisBC's customers.
- Per section 60(1)(b.1), "the commission may use any mechanism, formula or other method of setting the rate that it considers advisable". Therefore, FortisBC's proposed rate rider is an acceptable type of rate to recover the costs of the proposed Innovation Fund. Please also refer to FortisBC's response to BCUC IR 1.79.1.

In the Creative Energy Vancouver Platforms Inc. (Creative Energy) Application for a CPCN for a Low Carbon Neighbourhood Energy System for Northeast False Creek and Chinatown Neighbourhoods of Vancouver (Creative Energy NEFC CPCN), Creative Energy requested approval of a Carbon Reduction Rider and Fund, which it described as follows on pages 75 and 76 of the application:

> Creative Energy will accumulate and hold the proceeds of this Carbon Reduction Rider in the so-called Carbon Reduction Fund (with interest, at the utility WACC). The Carbon Reduction Fund will be used by Creative Energy for carbon reductions on behalf of the NES customers per CoV's [City of Vancouver's] direction (if applicable) and as approved the Commission. The expected use of these funds is to offset the costs of implementing either the larger Fuel Switch or Franchise Area Low Carbon Solution.[129]

In the Creative Energy NEFC CPCN Decision, the BCUC stated the following:

> The Panel denies the creation of the Carbon Reduction Rider and associated Carbon Reduction Fund. While the Panel acknowledges there are certain differences between the proposed Carbon Reduction Rider and the previously denied Carbon Emissions Rider by Corix in the UBC NDES CPCN Application,

[129] Creative Energy NEFC CPCN Application, Exhibit B-1, pp. 75-76.

the similarities are significant. In both cases, the amount collected from pioneer ratepayers will be accumulated for future use. Under those circumstances, such a rider would be inconsistent with 'Cost of Service' rate design principles.[130]

79.7 Please provide a detailed comparison of FortisBC's proposed Innovation Fund and rate rider with Creative Energy's requested Carbon Reduction Rider and Carbon Reduction Fund.

Response:

The nature of and reasons for FortisBC's proposed Clean Growth Innovation Fund and rate rider are not the same as Creative Energy's requested Carbon Reduction Fund and Carbon Reduction Rider. Below is a table providing a detailed comparison between the two of various areas.

	FortisBC Innovation Funds and Rate Rider	Creative Energy's Carbon Reduction Funds and Rate Rider
Objective	To accelerate innovation of clean energy solutions in stages of pre-commercialization. The focuses is providing cost effective, safe, and reliable solutions for FortisBC's customers while responding to climate policy aimed at GHG reductions.	To pre-collect and offset the cost of future capital expenditures (Creative Energy's Energy Supply Phase 2) for a utility-wide fuel switching solution or Franchise Area Low-Carbon Solution.

[130] Creative Energy NEFC CPCN Decision dated December 8, 2015, pp. 40–44.

	FortisBC Innovation Funds and Rate Rider	Creative Energy's Carbon Reduction Funds and Rate Rider
Use of Funding	Funds to be collected and used during the proposed MRP term (2020 to 2024). Funding intended for research and development activities that aim to advance clean energy solutions from feasibility research stage to system testing, launch and operation stage as discussed in Section C6.4.3.4 of the Application. Please also refer to Appendix C6 for list of specific activities that FortisBC intended to pursue with the funding. FortisBC does not expect to exceed the total funding level unless additional funding is approved by BCUC. Furthermore, the funding is not meant for capital expenditures currently commercially viable that will otherwise require separate BCUC approval. If, through research and development activities administrated under the Innovation Fund, pre-commercial technologies become technically and commercial viable as well as acceptable to FortisBC's customers and stakeholders in terms of cost effectiveness, safety, and reliability, FortisBC will seek approval for future expenditures for implementation, if necessary and subject to regulatory requirement at that time.	Funds were intended to be collected during Creative Energy's Phase 1 (2016 to estimated 2020) but will not be used until Phase 2 (estimated 2020 and beyond). However, as discussed in BCUC decision in the Creative Energy's 2015 NEFC CPCN Application, Creative Energy's Phase 2 is not within the scope of the Application and therefore, uncertainty surrounding the actual energy requirement of Phase 2 which makes the actual use of the Carbon Reduction Fund undefined. Furthermore, as per Creative Energy's response to BCUC IR 20.9 in the 2015 NEFC CPCN Application, the Carbon Reduction Rider will continue to be collected from its customers as long as its future Phase 2 is not implemented. It is also important to note that, as per Creative Energy's application, the Carbon Reduction Funds could also be used by the City of Vancouver (COV) for projects outside of Northeast False Creek (NEFC) upon COV's requests which creates a possibility of NEFC customers might not be benefited from the Carbon Reduction Funds at all.
Funding Level	Predictable and fixed at $4.9 million for gas and $0.5 million for electric over the proposed MRP period (2020 to 2024). FortisBC will seek BCUC approval for any additional funding required.	Variable and uncertain as Creative Energy's Carbon Reduction Funding is collected at a rate of $25 per tonne of GHG emission in 2016 with escalation at annual CPI. Therefore, the amount collected for Create Energy's Carbon Reduction Fund depends on the consumption level of its customers, annual CPI, as well as the timing of Phase 2 as discussed in the Use of Funding above.
Design of Rate Rider	Fixed basic charge rate rider and equal for all customers at $0.40 per month for gas customers and $0.30 per month for electric customers. FortisBC believes it is fair that all customers fund innovation activities equally since all customer types, not just higher volume users, will experience the benefits.	Volumetric based on amount of energy used by customers at a rate of $25 per tonne of GHG emission (equivalent to $4.16 per MWh) with escalation at annual CPI. It creates a price signal which high volume users will pay for the Phase 2 capital expenditure more than low volume users.

	FortisBC Innovation Funds and Rate Rider	Creative Energy's Carbon Reduction Funds and Rate Rider
Term	Fixed – Over the proposed MRP period (2020 to 2024).	Uncertain – Will continue to collect Carbon Reduction Rider as long as Phase 2 is not implemented or COV has not required the use of the funding for its other low carbon projects outside of NEFC (i.e. not in Creative Energy's service areas).
End of Term Balance Treatment	Funds collected from customers not invested will be returned to customers at the end of the proposed MRP term (i.e. 2024).	Funds will not return to customers if not used in Phase 2. The Carbon Reduction Rider will continue as long as Phase 2 is not implemented. COV also can request the use of the funds for other low carbon projects that is outside of NEFC (no benefit to Creative Energy's customers) if Phase 2 is delayed significantly or indefinitely. If Phase 2 occurs, Creative Energy proposed to apply the total balance of the Carbon Reduction Fund as Contribution in Aid of Construction (CIAC) and amortize the balance over the life of the Phase 2 capital asset.
Benefits to Local Communities	As shown with potential innovation activities in Appendix C6, the Innovation Funds will create opportunities for local communities as FortisBC intended to work with private organizations locally in BC if available and also engage research labs at UBC and UNBC.	No benefit to local communities. Creative Energy will accumulate and hold the Carbon Reduction Fund until Phase 2 occurs or COV requests the use of the funds for other low-carbon project outside of NEFC.
Reporting	FortisBC will be accountable to the BCUC in its administration and oversight of the Fund. FortisBC will provide annual update on the progress on approved projects as part of its Annual Review process. For transparency, the Fund will be recorded in a non-rate base deferral account over the proposed term of the MRP.	Uncertain – Creative Energy has not provided reporting and accounting treatment of the Carbon Reduction Fund and Rate Rider. Creative Energy also have not indicated in its Application if the Fund will be recorded in rate base or non-rate base deferral account.

79.8 Please explain whether any of the issues/concerns identified by the BCUC in the Creative Energy NEFC CPCN Decision are applicable to FortisBC's requested Innovation Fund and rate rider. If yes, please explain how FortisBC's proposals address the issues/concerns raised by the BCUC. If no, please explain why not.

Response:

The issues/concerns identified by the BCUC in the Creative Energy NEFC CPCN Decision are not applicable to FortisBC's proposed Innovation Fund and rate rider. Below are a list of issues/concerns quoted from BCUC Order C-12-15 and Decision in the Creative Energy NEFC CPCN Application and the reasons that these issues/concerns are not applicable to FortisBC's proposal:

1. ***"The amount collected from pioneer ratepayers will be accumulated for future use. Under those circumstances, such a rider would be inconsistent with 'Cost of Service' rate design principles"***

   This concern identified by the BCUC on Creative Energy's Carbon Reduction Rider is not applicable to FortisBC. FortisBC's Innovation Fund is not collected from current ratepayers and accumulated for future use like Creative Energy's Carbon Reduction Fund and Carbon Reduction Rider, which is a pre-collection of capital intended to offset the costs of future capital expenditure. FortisBC's proposed Innovation Fund is to be collected and used over the MRP term (2020 to 2024). Therefore, there is no inconsistency with Cost of Service rate design principles.

2. ***"Uncertainty as to the purpose of the future deployment of the CRR (Carbon Reduction Rider)"***

   This concern identified by the BCUC on Creative Energy's Carbon Reduction Rider is not applicable to FortisBC. The use of FortisBC's Innovation Fund is well defined with specific examples of research and development activities and pilots projects discussed in Appendix C6. As stated in the Application, 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. These clean energy solutions are currently in the pre-commercialization stage and have the potential to be cost-effective, safe and reliable solutions for FortisBC's customers. In contrast, the purpose of Creative Energy's Carbon Reduction Rider is uncertain as it can be intended for Creative Energy's Phase 2, which is not defined when the Carbon Reduction Rider is charged to Creative Energy's customers, or used by COV for low carbon projects that are unrelated to NEFC (i.e. unrelated to Creative Energy's customers). In addition, the timing of Creative Energy's Phase 2 is undefined and can be delayed significantly or indefinitely.

3. ***"The appearance of the CRR acting as an additional form of taxation"***

   This concern identified by the BCUC on Creative Energy's Carbon Reduction Rider is not applicable to FortisBC. Unlike Creative Energy's proposed Carbon Reduction Rider, FortisBC's proposed Innovation Fund rate rider is not a volumetric charge and is not tied to customers' volume or GHG emissions. FortisBC's Innovation Fund rate rider is a fixed amount and is equal for all customers at $0.40 per month for gas customers and $0.30 per month for electric customers. FortisBC's Innovation Fund rate rider does not

create a price signal similar to a form of carbon tax such that higher volume users will pay more for innovation due to their energy requirements.

4. ***"Phase 2 is not within the scope of this application (Creative Energy's NEFC CPCN Application) and that Phase 2 Energy Supply is yet to be determined creates sufficient uncertainty in the Panel's view to raise concerns over the reasonableness of collecting the CRR from initial NEFC ratepayers to be held "in trust" by Creative Energy, particularly given the wording in the NEA which contemplates these funds could be used for other low carbon projects unrelated to the NEFC"***

This concern identified by the BCUC on Creative Energy's Carbon Reduction Rider is not applicable to FortisBC. As discussed above, FortisBC's Innovation Fund is collected and used over the MRP term. No funds will be held "in trust" or held for use in future phases. The fund will be used on research and development activities during the term of the MRP for clean energy solutions that are related to FortisBC's customers.

5. ***"There are other rate mechanisms available to deal with rate shock, if this issue arises when transitioning to Phase 2"***

This concern identified by the BCUC on Creative Energy's Carbon Reduction Rider is not applicable to FortisBC. The purpose of FortisBC's Innovation Fund and rate rider is not for potentially mitigating rate shock.

80.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.6, pp. C-145 – C-146

Reporting

80.1 Please discuss whether FortisBC considers it appropriate to establish performance targets and key success indicators to monitor and evaluate the progress and achievements of the Innovation Fund activities.

Response:

FortisBC believes it is important to establish clear criteria for each initiative funded by the Clean Growth Innovation Fund. However, measuring the completion of initiatives by performance targets or key success indicators may be difficult.

For example, funding may be allocated to establish a test facility for blending hydrogen into natural gas pipelines. The completion of the test facility is easy to measure by objective criteria, but a performance target or success indicator is more difficult to envision. The benefit to customers of such an initiative would ultimately be the safe and economical reduction of emissions in the FEI pipeline system.

Another example might be a project to study and reduce the fugitive emissions from LNG storage and transfer operations. Such a study is expected to yield useful results, but quantifying the amount of fugitive emission reduction expected before the study is performed is the reverse of the correct process.

So, while it may be possible to measure leading indicators of success in terms of completing projects on time, on budget and within scope, further lagging criteria could not be established on a broad basis in advance.

80.1.1 If no performance targets or key success factors are necessary, please explain why not. Please also discuss how ratepayers may be able to evaluate how the funds, as collected through the rate rider process, are being utilized.

Response:

Please refer to the response to BCUC IR 1.80.1. Ratepayers will be able to evaluate success by looking at the leading indicators in terms of completing projects on time, on budget and within

scope, and additionally, at the lagging indicators specific to individual innovation projects that have been completed and by the specific benefits that are expected to be achieved from each.

80.2 In the event that FortisBC was directed to establish performance targets and key success indicators to monitor and evaluate the progress and achievements of the Innovation Fund activities, please explain how FortisBC would address such a directive. As part of this response, please discuss how these targets and key success indicators would/should relate to the implementation of the CleanBC targets.

Response:

As described in the response to BCUC IR 1.80.1, it is probably possible only to establish simple project completion criteria. The contribution to CleanBC targets may be clear (as with the examples cited in the response to BCUC IR 1.80.1), but quantifying the contribution may be difficult or impossible.

FortisBC expects to report on the following items related to the Clean Growth Innovation Fund at the Annual Reviews, plus any other items as directed by the BCUC:

- Description and status of current projects;
- New initiatives granted funding and current initiatives granted additional funding;
- Completed project milestones; and
- Project benefits (if successfully commercialized).

As the innovative project portfolio is expected to be quite dynamic, it is not possible to set annual performance targets at a portfolio level. Individual projects within the portfolio will have specific criteria they need to achieve.

80.2.1 As part of the above response, please discuss how often such targets and indicators should be measured and reported (e.g. annually? quarterly?)

Response:

Please refer to the response to BCUC IR 1.80.2.

80.2.2 As part of the above response, please discuss whether these performance targets should be included in each of FEI and FBC's SQIs.

Response:

FortisBC does not believe that the innovative project completion results should be included in FEI and FBC SQIs. This is due to the fact that each innovative project may vary significantly in its purpose and success criteria (aside from completion). Further, the SQIs have a specific purpose in an MRP, which is tied to ensuring that any efficiencies and cost reductions in O&M and capital that are obtained do not result in a degradation of the quality of service to customers. The Innovation Fund does not measure this.

80.2.3 For those activities that may not have fully met each of the key success indicators identified at the onset, should there be a penalty to FortisBC? Please discuss.

Response:

No, it would not be reasonable to penalize FortisBC for individual innovation projects that do not achieve their expected milestones. It is the nature of research and development activities that not all projects will succeed, and as such a portfolio approach is used. The success of a research and development activity – such as the advancement of a new technology to commercialization – is not something in FortisBC's control, but is subject to the limits of current technological knowledge, whether a scientific or technological breakthrough will occur, and so on. FortisBC cannot be reasonably penalized for something of this nature.

80.2.4 Please discuss the timing of a potential final evaluation report (which may include an evaluation of the innovation activities and whether they

have met each of the proposed key success indicators identified at the onset). Should there also be a mid-term report? Please discuss why or why not.

Response:

FortisBC believes that the information that it will report in each of the Annual Reviews during the term of the proposed MRPs will be sufficient and that a final evaluation report and mid-term report would duplicate the information already provided.

81.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.5.1, pp. C-142 – C-143

Purpose, Objectives and Guiding Principles

On page C-143 of the Application, FortisBC describes the following guiding principle underpinning the design and operation of the proposed Innovation Fund:

> **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.

81.1 Please identify and discuss the "customer benefits" of the proposed Innovation Fund. As part of this response, please specifically address the following customer benefits: (i) cost effectiveness; and (ii) safety and reliability.

Response:

FortisBC provided a number of examples of customer benefits that were achieved from innovation funds in other jurisdictions in Section C6.3 and Appendix C6 of the Application.

These benefits cited include:

- **Gas Research Institute:** "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." (Application, p. C-133, lines 21-23).
- **Low Carbon Networks Fund:** "… 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." (Application, p. C-135, lines 21-23).
- **Low Carbon Initiative Fund:** "Customer benefits included abatement which can reduce customers' carbon and energy costs, as well as increasing customer choice for affordable energy options." (Application, p C-136, lines 31-33).

FortisBC believes that the proposed Clean Growth Innovation Fund will result in the type of benefits cited above, including a return on investment and improved energy choices.

FortisBC intends to positively impact safety and reliability by pursuing initiatives that will:

- Improve and reduce the cost of pipeline inspections;

- Address gas supply disruptions using demand response measures in addition to supply side measures; and
- Improve electric system reliability using storage and distribution generation technologies.

81.2 Please discuss what methods will be used to evaluate customer benefits relative to the customer investments in the proposed Innovation Fund. How will FortisBC demonstrate the costs and benefit to customers? Please explain.

Response:

Please refer to the response to BCUC IR 1.80.1. Not every innovative initiative will result in immediate benefits to customers. For those that do, FortisBC expects to report on these benefits at the Annual Reviews.

82.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section C6.4, p. C-142; Workshop Transcript, pp. 50–51

Forecast Clean Growth Expenditures

On page C-142 of the Application, FortisBC provides the following table:

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

FortisBC further states on page C-142 of the Application: "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."

On pages 50–51 of the Workshop Transcript, FortisBC stated the following:

> Yeah, in all cases – so I mean when we look at the commercial side of electric vehicles, for example, we'll be definitely pursuing government grants and we have received some already for station installation. On the pre-commercial, you know, on the actual R&D activities and demonstration activities, there is government funding available. It's not quite as easy to access but we'll certainly be pursuing it where it exists.

82.1 For each investment area identified in Table C6-2 of the Application, please provide the total maximum available government grants, if any (please include the maximum available grants from all levels of government).

Response:

It is not possible to state in advance the type or amount of government grants that may be available for the innovative activities that will be pursued. Funding programs change rapidly. However, based on the current environment and depending on the specific activity being pursued, funding for R&D activities or commercialization programs might be available from:

- Business Development Bank of Canada (federal);
- Natural Resources Canada (federal);
- Natural Sciences and Engineering Research Council (federal);
- BC Innovative Clean Energy fund (provincial);
- Impact Canada Challenges (federal); and
- Mitacs funding (not for profit).

In addition to the above, funding from provinces outside of BC may be available depending where research, development and demonstration activities take place.

82.2 For each identified investment area for the term of the proposed MRP, provide the following information (in table form, and separately for FEI and FBC):

- Estimated financing need for innovation activities;
- Estimated government grants to be received;
- Estimated funding from the Innovation Fund; and
- Total planned funding for the investment area (grants funding + Innovation Fund).

Response:

The estimated financing required for Innovation Activities, net of grants, in each investment area is provided in the response to BCUC IR 1.70.1. FortisBC has not estimated the amount of government grants expected in each area and therefore does not know the total planned funding amount for each investment area since this will depend on the amount of grants received. If grant funding is greater, then the total investment will be increased.

82.3 For each identified investment area (separately for FEI and FBC), please provide the innovation projects objectives and desired outputs.

Response:

Please refer to Appendix C6-4 of the Application for innovation project objectives and desired outputs.

82.4 For each investment area, and separately for FEI and FBC, please list specific projects which will be funded through the Innovation Fund.

Response:

Appendix C6-4 of the Application provides detailed objectives for projects. In some cases, FortisBC is aware of specific projects underway that could help achieve those objectives and may be eligible for funding. However, it cannot be determined at this time whether those projects will still be active, or whether other projects may be more appropriate, at the time that the Clean Growth Innovation Fund may be approved.

82.4.1 Please explain whether the Innovation Fund will be used to fund any of the ongoing research and pilot projects. If so, please identify those projects. Please also explain why pilot projects would not be appropriately categorized under the sections of the GGRR.

Response:

The Clean Growth Innovation Fund is not expected to fund existing research and pilot projects aside from those started with the Natural Gas Innovation Fund (NGIF). DSM-related pilot projects have a separate fund. FortisBC does not believe that pilot programs are generally supported by the GGRR (with the exception of certain electrification undertakings) and consequently none are underway. Please also refer to the response to BCUC IR 1.73.12.

82.5 Please explain the criteria which will be used for project prioritization and selection.

Response:

The criteria for project prioritization and selection have not yet been finalized, but are likely to include:

- Alignment with Innovation Fund objectives;
- Eligibility for government grants;
- Other funding arrangements;
- FortisBC contribution amount;
- Proponent management team; and
- Project plan and timelines.

82.6 Is FortisBC aware of any other private or public entities in (i) British Columbia and/or (ii) Canada conducting research in the identified investment areas? If yes, please identify and describe these entities and their research activities. Please also explain how FortisBC plans to address the potential issue of duplication of research.

Response:

Yes, FortisBC is aware that other entities are conducting research into the identified investment areas. FortisBC intends to partner with other entitles in all innovation activities.

Further, duplication of research toward the same goal can be beneficial. For example, FortisBC is aware that UBC is conducting research into using wood waste to create biomethane, and that other academic institutions and private companies in Canada are pursing similar projects which may increase the number of promising technologies. Similarly, it is possible that, with a key technology such as wood waste biomethane, FortisBC may fund multiple distinct projects in order to improve the probability of developing a commercially viable technology.

By establishing a central governing committee for expenditures and ensuring that the governing committee is as aware as possible of the research being conducted in each investment area, FortisBC intends to optimize the use of the Innovation Fund.

82.7 Please discuss under what circumstances activities/projects in one investment area could be halted and funds allocated from one investment area to another.

Response:

Potential reasons for halting a particular innovation project and redirecting funding are numerous and could include such factors as:

- Higher-priority research requires funding;
- A project may fail to achieve it objectives in a timely or cost effective manner;
- A key person may leave a project;
- A company may go bankrupt; or
- A commercial product becomes available that solves a particular area of research.

82.7.1 Please discuss the decision-making process and the role of all three governance bodies in a decision to re-allocate the funds from one area to another.

Response:

The decision-making process and role of the three governance bodies in a decision to re-allocate the funds from one area to another are as follows:

1. The role of the Executive Steering Committee will be to establish guidelines for the potential reallocation of funds.
2. The role of the External Advisory Council will be to make recommendations to the Working Group on the reallocation of funds.
3. Within the guidelines established by the Executive Steering Committee and considering the recommendations of the External Advisory Council, the role of the Working Group will be to make decisions regarding reallocation of funds.

82.8 If FortisBC's proposal to fund innovation through rate riders is not approved, would FortisBC proceed with its planned innovation activities in the identified investment areas?

Response:

FortisBC would be unable to proceed with the innovation activities in the identified investment areas due to a lack of funding within the index-based O&M proposed. Please also refer to the response to BCUC IR 1.26.10.

82.8.1 If yes, please explain how FortisBC would propose to recover the associated costs and whether, as an example, the cost recovery proposals would be based on the merits of the project(s) on a case-by-case basis.

Response:

Please refer to the response to BCUC IR 1.82.8.

82.8.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.82.8.

83.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, Section B1.2.5, p. B-7; Workshop Transcript, p. 44; FEI 2017 Long-term Gas Resource Plan (LTGRP) Decision and Order G-39-18, p. 23

Environmental Policy and Long-term Resource Plans

On page B-7 of the Application, FortisBC states the following:

> 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 (CO2) 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. 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.

On page 23 of the FEI 2017 LTGRP Decision, the BCUC stated the following:

> In the next LTGRP, the Panel directs FEI to address the implications for FEI's long-term resource and conservation planning of the 2018 CleanBC plan released by the Government of BC on December 6, 2018 and to provide an update on its analysis of GHG targets. In particular, the Panel expects that FEI should address the long term impacts to FEI of:
>
> - Initiatives targeting more energy efficient buildings, in terms of gas demand and FEI's DSM activities;
> - Requirements for 15 percent of natural gas consumption to be from renewable gas;
> - Industrial electrification, with respect to demand for natural gas;
> - How 2018 CleanBC's plans for clean transportation affect FEI's forecast for its NGT programs; and
> - Other initiatives to be developed by the Government of BC over the next 18 to 24 months.

83.1 Please explain why it would not be more appropriate for FortisBC to complete the analysis, as directed by the BCUC in the FEI 2017 LTGRP Decision, prior to requesting approval of the Innovation Fund and rate rider.

Response:

It is most appropriate for FortisBC to request approval of the innovative funding in this Application for the following reasons:

1. There is an undesirable opportunity cost in delaying the funding of studies into technology innovation that could help lower carbon emissions and improve service to customers until sometime after submission of the next LTGRP in 2022;
2. Aspects of the CleanBC Plan were sufficiently considered in the 2017 LTGRP such that further analysis and conclusions in the next LTGRP are not required in order to assess the merits of FortisBC's proposed Clean Growth Innovation Fund;
3. The Clean Growth Innovation Fund as described in the Application is intended to provide broad clean energy benefits to customers and should not be interpreted to address only those aspects of the CleanBC Plan identified in the captioned BCUC directive in the 2017 LTGRP Decision; and
4. It is unlikely that the main innovation activities relevant to resource planning identified in Appendix C6-4 would be considered inappropriate in the next LTGRP. The risk of needing to make adjustments to the Clean Growth Innovation Fund later in the MRP period are small compared to the potential opportunity cost of not being able to explore technology innovations until 2023 or later.

To explain further:

1. Seeking innovation funding now rather than later in the MRP horizon is prudent because stable innovation funding across the MRP horizon will enable the Companies to promptly and proactively begin to confront changes in their operating environment. Delaying the ability to participate in studies and investigations into innovative new technologies could delay the ability to implement some of those technologies that might prove successful in utilizing natural gas infrastructure to lower carbon emissions and/or improve energy service to customers. From past experience in LTGRP regulatory review processes, FortisBC would expect a decision on the next LTGRP in early to mid-2023. If FortisBC is made to wait until after the BCUC's decision on the next LTGRP in order to begin funding these studies and investigations, the earliest the Clean Growth Innovation Fund could have an impact on this important work would be sometime later in 2023. Given the urgency of the carbon emissions issue and the CleanBC target dates, as well as considering the few currently available alternatives for addressing carbon emissions and improving choice for customers, FortisBC believes it should have access to the Clean Growth Innovation Fund as soon as possible.
2. Although the CleanBC Plan is a recent policy document, the development of carbon reduction targets and regulations by the BC Government (for example the GGRR, and Demand-side Measures Regulation Amendments) have a longer history that have been

accounted for in developing FortisBC's proposal for a Clean Growth Innovation Fund. The overall direction of such GHG reduction policies has not changed since FortisBC submitted its most recent resource plans. The CleanBC Plan is another step in the Province's plan to reduce carbon emissions and the direction and possible future magnitude of the changes is clear enough today to assess the merits of the proposed Clean Growth Innovation Fund without waiting for the incremental analysis in the LTGRP directed by the BCUC. Further, while the LTGRP takes an integrated long term look at future scenarios, demand and need for resources, it is the work of the individual business units within FortisBC that use this longer term look, assess changes in their operating environment and determine what is needed in the nearer term. This shorter term needs-assessment by the FortisBC business units has been utilized in developing the proposed Clean Growth Innovation Fund and further long-term analysis as part of the next LTGRP is not necessary prior to establishing the Fund.

3. The Clean Growth Innovation Fund is intended to consider the issue of carbon emissions as a whole, and not just the items contained in the CleanBC Plan. Since the five bullets noted in the BCUC's directive refer to a subset of the considerations that the Clean Growth Innovation Fund is intended to address, delaying a decision on merits of the Clean Growth Innovation Fund until the next LTGRP process would unnecessarily delay consideration of other attributes of the Clean Growth Innovation Fund application. Examples of other considerations for the Clean Growth Innovation Fund that are not accounted for in the five bullet points in the BCUC's directive include carbon sequestration at the end use or from the atmosphere that could lower emissions from using natural gas. Other new technologies not yet considered could also become the subject of Clean Growth Innovation Fund expenditures and could inform future carbon reduction policies and initiatives rather than addressing only the current initiatives already defined in the existing CleanBC Plan.

4. Urgency is required in planning and implementing carbon reduction initiatives. The opportunity cost of delaying investigations into technology innovations that could utilize the natural gas infrastructure to reduce carbon emissions at reasonable costs is discussed in item 1 above. Alternatively, the risks of potentially needing to make changes to the Clean Growth Innovation Fund as further policy work by the government and further analysis by the utility for LTGRP or other initiatives takes place is relatively low. Given that the directional impact of the CleanBC Plan on FortisBC's business is already known (e.g. industrial electrification will reduce demand for natural gas), the analysis that the BCUC has directed FEI to complete for its next LTGRP is expected to only reinforce the need for the Clean Growth Innovation Fund. It might also provide insights that FortisBC could use to make adjustments to the implementation of the Clean Growth Innovation Fund. As such, waiting for the completion of the analysis in the next LTGRP holds greater risk in opportunity costs than do the relatively minor costs of making adjustments to the plan, if needed, once it is implemented.

83.1.1 Please explain the timeline for FortisBC to complete the analysis outlined in the FEI 2017 LTGRP Decision and to evaluate the funding needs required to meet the CleanBC requirements.

Response:

The BCUC has directed FortisBC to submit its next LTERP by the end of 2021 and the LTGRP by March 2022. The Companies' recent experience in regulatory proceedings for resource plans suggests that the BCUC's decisions on the LTERP and LTGRP will be available by late 2022 and early to mid-2023, respectively. Please also refer to the response to BCUC IR 1.83.1.

The results of various investigations to be undertaken using the Clean Growth Innovation Fund will be as important, or more important, an input into determining the cost of future decarbonization initiatives than will be the analysis FortisBC has been directed to include in its next LTGRP. Therefore, the Clean Growth Innovation Fund needs to be established as soon as possible, well before decisions on the next LTERP and LTGRP can be made.

On page 44 of the Workshop Transcript, FortisBC stated the following:

> To the extent those monies aren't spent in any particular year, we will be recording those differences in a deferral account, and to the extent that there is anything left at the end of the MRP period we'll be applying for dispensation of those unused funds.

83.2 Please explain why it would not be more appropriate, as opposed to requesting approval of the Innovation Fund and rate rider as part of this Application, to integrate the request for this fund/rate rider with FEI and FBC's long-term resource planning and to request approval through those applications.

Response:

Please refer to the responses to BCUC IRs 1.83.1 and 1.83.1.1.

H. SERVICE QUALITY INDICATORS

84.0 Reference: FEI SERVICE QUALITY INDICATORS

Exhibit B-1, Section C7.2, p. C-148; Exhibit B-1-1, Appendix C5-1, p. 2; FEI PBR Decision, p. 155

FEI's Proposed Service Quality Indicators

Page C-148 of the Application states: "[f]or 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."

84.1 Please further explain FEI's approach to reviewing and assessing the appropriateness of the existing Service Quality Indicators (SQI). As part of this response, please discuss the scope of the review, the review methodology and the key findings.

Response:

FEI's approach to reviewing and assessing the appropriateness of the existing SQIs was to build on the experience of the Current PBR Plan and the stakeholder feedback received. In reviewing the existing SQIs, FEI took into consideration feedback provided by stakeholders as part of the Annual Review process and also considered that there are fewer costs captured under an indexing formula in the proposed MRP than is the case in the Current PBR Plan.

As a result of stakeholder feedback, FEI added a new metric, Average Speed of Answer, an informational indicator to replace the existing Telephone Abandonment rate. Additionally, FEI's focus was on refining its existing suite of SQIs (i.e., updating benchmarks/thresholds) which have worked well in providing an appropriate balance of metrics focused on safety, reliability and responsiveness to customer needs. FEI also recognized there are a number of additional metrics and indicators that are being introduced elsewhere in the Application (i.e., Incentives).

FEI believes the current suite of SQIs have been appropriate and useful and will remain so for the term of the MRP in monitoring the performance of FEI to ensure that any efficiencies and cost reductions do not result in a degradation of service quality.

On page C-148 of the Application, FEI provides Table C7-1 which provides a comparison of FEI's current and proposed SQIs.

On page 2 of Appendix C5-1, FEI states that "[b]enchmarks typically reflect either industry standards or the Company's performance over recent prior periods".

84.2 For each SQI with a Benchmark and Threshold, please explain the methodology used to determine the benchmark (for example three-year average from 2010 to 2012, industry average etc.). Please provide the data used to calculate each benchmark.

Response:

Following is the requested FEI information for each existing SQI with an explanation of the methodology used to determine the existing approved benchmarks.

1

Indicators with Benchmarks	Current Benchmark	*2010* Annual Results	*2011* Annual Results	*2012* Annual Results	Approved Methodology
Emergency Response Time - Calls responded to within one hour	>= 97.7%	97.7%	97.9%	97.4%	Average of three year results from 2010 to 2012 as directed by BCUC.
Telephone Service Factor (Emergency) - Calls answered in 30 seconds or less	>= 95%	3 year average not applicable			Approved benchmark of 95% recognizes an appropriate balance between cost and services levels.
All Injury Frequency Rate	<= 2.08	2.66	1.66	1.91	Average of three year results from 2010 to 2012 as directed by BCUC.
Public Contacts with Gas Lines	<= 16	18	16	13	Average of three year results from 2010 to 2012 as directed by BCUC.
First Contact Resolution	>= 78%	3 year average not applicable			The current benchmark approved by the BCUC at 78 percent based on setting a target that was above the industry average for call centre performance (i.e. 2012 SQM 71%).
Billing Index	<= 5	3 year average not applicable			Approved Benchmark of 5 based on achieving specific performance for each of billing sub-measures (i.e. bill timeliness, etc.).
Meter Reading Accuracy - Number of scheduled meter reads that were read	>= 95%	3 year average not applicable			Approved benchmark of 95% based on service level required in meter reading contract.
Telephone Service Factor (Non Emergency) - Calls answered in 30 seconds or less	>= 70%	3 year average not applicable			Approved benchmark of 70% recognizes an appropriate balance between cost and services levels.
Meter Exchange Appointment Activity	>=95%	94.2%	96.5%	96.5%	95% based in part on the average of 2010 (94.2%), 2011 (96.5%), 2012 (96.5%) = 95.7%.

2

3

84.3 For each SQI with a Benchmark and Threshold, and using the methodology identified in the previous IR response, please calculate the benchmark based on FEI's performance over the recent period. For example, where a three-year average from 2010 to 2012 was used, the benchmark is to be recalculated based on the three-year average for the period 2016 to 2018.

Response:

Using the methodology identified in the response to BCUC IR 1.84.2, the following is the calculation of the proposed benchmarks for the metrics based on the FEI's performance over the recent period (i.e., average of 2016 to 2018 results). FEI also provides comments on the basis used for determining the proposed benchmark and for differences from a suggested three-year average approach for each metric. For some metrics, the methodology used and approved were based on factors other than performance in recent years.

1

Indicators with Benchmarks	**Current** Benchmark	***Proposed*** Benchmark	***2016*** Annual Results	***2017*** Annual Results	***2018*** Annual Results	***Average*** 2016 - 2018	Comments
Emergency Response Time - Calls responded to within one hour	>= 97.7%	>=97.7%	97.4%	97.8%	97.8%	97.7%	Proposed benchmark for MRP is based on 3 year average of 2016 to 2018 results.
Telephone Service Factor (Emergency) - Calls answered in 30 seconds or less	>= 95%	>=95%	98.5%	97.6%	97.9%	98.0%	Three year average methdology not applicable. Proposed benchmark of 95% recognizes an appropriate balance between cost and service level as was determined in the PBR proceeding.
All Injury Frequency Rate	<= 2.08	<= 2.08	2.13	1.36	1.74	1.74	Three year average methodology not applicable. Current benchmark remains appropriate as the Company assesses the trend and sustainability of recent years' safety performance.
Public Contacts with Gas Lines	<= 16	<=8	8	9	8	8	Proposed benchmark for MRP is based on 3 year average of 2016 to 2018 results.
First Contact Resolution	>= 78%	>=78%	81%	80%	83%	81%	Three year average methodology not applicable. The current benchmark approved by the BCUC at 78 percent based on setting a target that was above the industry average for call centre performance (i.e. 2012 SQM 71%). Recent industry average for call centre performance (i.e. 2018 was 70%) remains consistent with 2012 comparator.
Billing Index	<= 5	<=3	0.57	0.75	2.63	1.32	Proposed benchmark of 3 is reflective of most recent years' performance instead of existing benchmark of 5 which was based on achieving specific performance for each of billing sub measures. The 3.0 benchmark is consistent with the recent year's result of 2.63 experienced in 2018.
Meter Reading Accuracy - Number of scheduled meter reads that were read	>= 95%	>=95%	97%	96%	95%	96%	Three year average methdology not applicable. Proposed benchmark of 95% based on service level required in meter reading contract.
Telephone Service Factor (Non Emergency) - Calls answered in 30 seconds or less	>= 70%	>=70%	71%	71%	71%	71%	Three year average methdology not applicable. Proposed benchmark of 70% recognizes an appropriate balance between cost and service level as was determined in the PBR proceeding.
Meter Exchange Appointment Activity	>=95%	>=95%	96.9%	97.0%	96.3%	97%	Proposed benchmark of 95%, recognizing that average of recent years' performance is marginally higher.

2

In addition to the above comments, FEI believes the proposed benchmarks for the TSF (emergency) of 95 percent and the TSF (non-emergency) of 70 percent reflect that the desired service quality level considers the costs of providing that level of service. This was acknowledged in the 2014-2018 PBR proceeding by interveners and the BCUC. Accordingly, FEI believes that the same benchmarks approved for the Current PBR Plans continue to represent the appropriate balance between cost and service level.

For AIFR, the current benchmark remains appropriate as the Company assesses the trend and sustainability of recent years' safety performance. The AIFR results have improved in recent years, but they should be monitored and reviewed on a longer term and trend basis, before the existing benchmark is adjusted to reflect recent historical performance.

84.4 Where the benchmark calculated in response to the above IR exceeds the Current Benchmark identified in Table C7-1 of the Application, please discuss whether FEI considers it appropriate to adjust the benchmark accordingly.

Response:

Please refer to the response to BCUC IR 1.84.3.

84.4.1 If no, please explain why not and please explain under what criteria FEI would consider for adjusting the benchmark.

Response:

Please refer to the response to BCUC IR 1.84.3.

On page 155 of the FEI PBR Decision, the BCUC stated the following:

> In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

84.5 For each SQI with a Benchmark and Threshold, please confirm, or explain otherwise, whether FEI reviewed the appropriateness of the thresholds, taking into consideration the factors identified above.

Response:

Confirmed.

In the review process to determine the appropriateness of continuing to use the existing thresholds, FEI considered the factors as listed in the question, with a particular focus on considering the actual performance of the metric during the term of the Current PBR Plan. Less emphasis was placed on reviewing metric performance in other jurisdictions, recognizing the metric benchmarks and thresholds that have worked successfully for the Current PBR Plan reflect the particular circumstances and situation for FEI and the interests of the stakeholders involved.

84.5.1 If confirmed, please discuss the findings of FEI's review and explain how the findings were applied to the proposed SQIs.

Response:

Following is discussion of different metric thresholds and the rationale used by FEI in determining proposed changes to the existing thresholds.

	Current Threshold	***Proposed*** Threshold	Comments
Emergency Response Time - Calls responded to within one hour	96.2%	96.2%	Factoring in the actual performance from 2014 to 2018 suggests the same threshold as the existing threshold of 96.2% based on a benchmark of 97.7%. This is consistent with that the proposed benchmark based on recent years' performance is the same as the existing benchmark.
Telephone Service Factor (Emergency) - Calls answered in 30 seconds or less	92.8%	92.8%	Factoring in the actual performance from 2014 to 2018 suggests the same threshold as the existing threshold of 92.8% based on a benchmark of 95%.
All Injury Frequency Rate	2.95	2.95	Factoring in the actual performance from 2014 to 2018 suggests no significant change to the historical volatility for this metric. The benchmark and threshold remain appropriate as the Company assesses the trend and sustainability of recent years' safety performance.
Public Contacts with Gas Lines	16	12	The threshold has been lowered to 12 to reflect expected historical volatility going to back to about 2012.
First Contact Resolution	74%	74%	The threshold was established during the current PBR as the result of discussions between stakeholders and FEI. FEI believes the same threshold remains appropriate reflecting historical volatility observed.
Billing Index	<=5	5	The existing threshold of 5 remains appropriate as it is based on achieving specific performance for each of billing sub measures.
Meter Reading Accuracy - Number of scheduled meter reads that were read	92%	92%	Factoring in the actual performance from 2014 to 2018 suggests the same threshold as the existing threshold of 92% based on a benchmark of 95%.
Telephone Service Factor (Non Emergency) - Calls answered in 30 seconds or less	68%	68%	The threshold was established during the current PBR as the result of discussions between stakeholders and FEI. FEI believes the same threshold remains appropriate reflecting historical volatility observed.
Meter Exchange Appointment Activity	93.8%	93.8%	The threshold was established during the current PBR as the result of discussions between stakeholders and FEI. FEI believes the same threshold remains appropriate reflecting historical volatility observed.

1

84.5.2 If not confirmed, please discuss why the appropriateness of the thresholds were not assessed, explaining under what circumstances FEI would consider reviewing the thresholds.

Response:

Please refer to the response to BCUC IR 1.84.5.1.

84.6 Please discuss whether, in its review of the existing SQIs, FEI considered adopting any new SQIs.

Response:

In reviewing its existing SQIs, in addition to the replacement of the current informational SQI Telephone Abandonment Rate with the new informational SQI Average Speed of Answer, FEI considered adopting additional Safety related measures to complement the existing AIFR metric used to measure employee safety. FortisBC is looking into introducing other indicators of safety performance, which are leading indicators that capture the presence of "safety" and occurrence of proactive activities like safety observations and inspections. Further work on investigating this new approach to measuring safety performance through both lagging and leading indicators is required. FortisBC has not progressed enough to be in a position to propose new safety related measures at this time.

FortisBC believes its existing suite of SQIs have worked well in providing an appropriate balance of metrics focused on safety, reliability and responsiveness to customers' needs. As a result, our focus has been on refining the existing suite of SQIs and not necessarily on adding new SQIs. Further, adding more SQIs does not necessarily contribute meaningfully to the monitoring of the utility's overall performance so that there is no degradation of service quality during the term of the proposed MRP.

84.6.1 If yes, please provide details of any SQIs considered and the reasons for their ultimate rejection.

Response:

Please refer to the response to BCUC IR 1.84.6.

84.6.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.84.6.

85.0 Reference: FEI SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C4-2; pp. 1, 18, 29; Appendix C5-1, p. 1

SQI Selection Criteria

On page 1 of Appendix C5-1, FEI states the following:

> In developing the proposed suite of Service Quality Indicators for the current Application, the criteria used to establish the SQIs for the past PBR plans in 1998, 2004 and 2014 were considered, as FEI believes that the criteria are still appropriate. The criteria are presented in Table A:C5-1-1 below.

Table A:C5-1-1: Criteria for the Design and Selection of SQIs

ID	Criterion	Description
1	Value to customers	The indicator must represent a service or service attributes that customers value.
2	Controllable	Only those indicators over which the Company has control should be included. SQIs should not be linked to exogenous events over which the actions of the Company's employees have little or no influence.
3	Cost effective	The information collection activities associated with the indicator must be cost effective.
4	Simple and transparent	The indicator should be simple to administer and results should be easy to understand and interpret.
5	Traceable and Quantifiable	The indicators should have been previously tracked to ensure they are stable over time. The indicators must be quantifiable.
6	Flexible	The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

In Appendix C4-2, FEI provides a jurisdictional analysis of MRPs and states the following:

> Specifically Alberta's second generation PBR plans for natural gas and electric distributors, the Ontario Energy Board's (OEB) renewed regulatory framework for Ontario's electric distributors, the Enbridge Gas Distribution (EGD) and Union Gas Amalco incentive rate-setting plan in Ontario, Hydro Quebec Distribution's (HQD) and Hydro Quebec Transmission's (HQT) first generation PBR plans are discussed in the following sections.

On page 18 of Appendix C4-2, FEI states that the OEB's Renewed Regulatory Framework for Electricity (RRF) Distributors employs a "comprehensive set of performance outcomes and uses a scorecard approach to effectively organize performance information in a manner that facilitates evaluations and meaningful comparisons."

The scorecard design includes four performance areas as summarized in Table A:C4-2-7:

Table A:C4-2-7: Performance Areas in Electricity Distributor Scorecard[16]

Performance Area	Description	Measures
Customer focus	Services are provided according to identified customer preferences	Includes indicators such as First contact resolution (FCR), Calls answered on time, Appointments met on time, Billing accuracy, Customer satisfaction surveys
Operational effectiveness	Continuous improvement in productivity and cost performance is achieved; utilities deliver on system reliability and quality objectives;	Includes safety (serious incident index, level of compliance with safety regulation, Level of public awareness), system reliability (SAIFI, SAIDI) , asset management (DSP implementation progress) and cost control (cost per km of line and per customer) metrics
Public policy responsiveness	Utilities deliver on obligations mandated by government	Conservation and demand management as well as connection of renewable generation metrics
Financial performance	Financial viability is maintained; savings from operational effectiveness are sustainable	Financial ratios related to utilities' liquidity (current ratio), leverage (total debt to equity ratio) and profitability

Further on page 29 of Appendix C4-2, FEI discusses the SQIs for the OEB's Union Gas and Enbridge Distribution Amalco Incentive Rate-Setting Plan:

> Consistent with Renewed Regulatory Framework document developed for electric distributors, the utilities proposed to use a single scorecard to measure and monitor performance over the rebasing period. The scorecard metrics included a combination of existing metrics, service quality indicators and best practice metrics. The utilities argued that the use of existing SQIs would help ensure that Amalco's progress can be compared relative to its past.
>
> The OEB determined the scorecard as proposed by the utilities is reasonable and therefore can be used for Amalco's [Incentive Regulation] plan. The OEB further determined that in addition to the SQIs, the Amalco should include two unit cost metrics for total cost per customer and total cost per KM of distribution pipeline.

85.1 Please explain whether, as part of FEI's review of the SQI selection criteria, FEI considered adjusting or adopting new criteria as a result of the information gathered as part of the jurisdictional review.

Response:

This response applies to similar questions asked for FBC including BCUC IR 1.90.5, 1.90.5.1 and 1.90.5.2.

The criteria presented in Table A:C5-1-1 are general guiding principles to consider in the selection and design of its SQIs. Criteria 2 to 6 as a group provide guidance more on

administrative aspects to be considered in selecting an SQI (i.e., cost effective, simple and transparent, traceable and quantifiable, etc.). Criteria 1 provides overall general guidance in selecting SQIs that customers value. In its jurisdictional comparison research undertaken, for the Alberta and Ontario jurisdictions, FortisBC did not find equivalent criteria stated explicitly. However, FortisBC believes that its broad selection criteria would apply in the other jurisdictions.

Regarding the actual areas for performance measurement used, there are similarities between its areas for performance measurement and those found in Alberta and Ontario. For example, common across the three jurisdictions are metrics focused on Customer Service and System Reliability. The following is an overview of the areas of focus for FortisBC, Ontario and Alberta.

FortisBC (FEI and FBC)

FortisBC historically has had, and is proposing to continue, a balanced suite of metrics that measures:

- Safety;
- Responsiveness to Customers Need; and
- Reliability.

The choice of these areas of focus and the specific SQIs to monitor what matters to FortisBC customers have evolved over time, reflecting BCUC direction and stakeholder and FortisBC input.

Ontario

In Ontario, the OEB has established performance outcomes that it expects utilities to achieve in four distinct areas:

- Customer Focus: services are provided in a manner that responds to identified preferences;
- Operational Effectiveness: continuous improvement in productivity and cost performance achieved; and utilities deliver on system reliability and quality objectives;
- Public Policy Responsiveness: utilities deliver on obligations mandated by government; and
- Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

Alberta

In Alberta, the AUC's Rule 002 sets out the minimum service standards and reliability performance monitoring for electric and natural gas distribution companies. The performance standards include:

- Reporting on customer meter reading and billing accuracy;
- Tariff billing accuracy;
- Work completion performance measures;
- Worker safety performance measures;
- Interruption duration and frequency thresholds; and
- Post-final adjustments processed by month in accordance to Section 5 of Rule 021 for electricity service.

FortisBC's proposed metrics are broadly aligned with the measures in Alberta and Ontario. The exception is Ontario's performance area on "Public Policy Responsiveness: utilities deliver on obligations mandated by government." For this performance area, FortisBC has proposed its Targeted Incentives focused on encouraging adoption of cleaner, lower emissions energy solutions and contributing to the realization of energy and emissions goals of government.

FortisBC has not completed a comprehensive comparison of its SQIs compared to the Alberta and Ontario jurisdictions as its approach to reviewing and assessing the appropriateness of the existing SQIs was to build on the experience of the Current PBR Plan and the stakeholder feedback received. Each jurisdiction's performance metrics reflect the particular circumstances and requirements of the jurisdiction. While useful to review other jurisdictions for consideration, there is no one size fits all solution across all the jurisdictions.

The current suite of SQIs have been appropriate and useful over the Current PBR Plan and remain so for the term of the proposed MRP to ensure that any efficiencies and cost reductions do not result in a serious degradation of service quality.

85.1.1 If yes, please discuss the items considered and provide reasons for their ultimate rejection.

Response:

Please refer to the response to BCUC IR 1.85.1.

85.1.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.85.1.

85.2 Please explain whether FEI identified the SQIs used for any of the jurisdictions reviewed and, if yes, please provide a summary of the SQIs for each applicable jurisdiction and discuss whether FEI considered adopting any of the SQIs identified.

Response:

Please refer to the response to BCUC IR 1.85.1.

85.2.1 For any SQIs common to FEI and other jurisdictions identified in the jurisdictional review, please provide a table comparing FEI's SQI results and those of the other utilities. Please comment on FEI's results compared to other utilities.

Response:

Please refer to the response to BCUC IR 1.85.1.

86.0 Reference: FEI PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

Exhibit B-1-1, Appendix C5-1, p. 11

Meter Reading Accuracy

On page 11 of Appendix C5-1, FEI provides the following table:

Table A:C5-1-11: Results during the PBR Plan for Meter Reading Accuracy

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Meter Reading Accuracy	97.0%	97.5%	96.9%	96.2%	95.4%	95%	95%	92%	92%

86.1 The results for the Meter Reading Accuracy SQI indicate a downward trend for the period 2014 to 2018. Please provide reasons for the downward trend and discuss FEI's proposed mitigation strategy for improvement over the proposed MRP term.

Response:

The results for Meter Reading Accuracy indicate a slight downward trend for the period 2016 to 2018, relative to 2014 and 2015, where this SQI measured the highest; however, the performance for all years remains within the threshold and at the benchmark

FEI believes recent declines in meter reading accuracy may be related to staffing issues Olameter was experiencing during this time as well as significant weather events. FEI and Olameter are currently working together to ensure Olameter meets its contractual obligations.

87.0 Reference: FEI PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

Exhibit B-1-1, Appendix C5-1, pp. 13–14

Customer Satisfaction Index (CSI)

On pages 13 and 14 of Appendix C5-1, FEI explains that it has "used the Customer Satisfaction Index (CSI) to assess overall customer satisfaction with the company's natural gas service" and that it is "planning to review the CSI index scoring and methodology."

87.1 Please explain when FEI is intending to review the CSI index scoring and methodology.

Response:

FEI expects to review the CSI index scoring and methodology later in 2019.

87.1.1 In the event that FEI's review of the CSI index scoring and methodology is revised as a result of the review, please explain whether FEI anticipates that these changes will be made during the proposed MRP term.

Response:

FEI is uncertain at this time whether changes to the Customer Satisfaction Index (CSI) scoring and methodology will occur and, if so, the timing of such changes. To the extent that FEI identifies that changes to the CSI scoring and methodology during the MRP term would be beneficial, FEI would bring this forward at an Annual Review for consideration.

88.0 Reference: FEI PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

Exhibit B-1-1, Appendix C5-15, pp. 15–16; FEI PBR Decision, p. 149

Telephone Abandonment Rate

With reference to the Telephone Abandonment Rate on page 15 of Appendix C5-1, FEI states that it "proposes to replace the existing metric with another Informational Indicator, Average Speed of Answer (ASA)."

On page 16 of Appendix C5-1, FEI provides the following table:

Table A:C5-1-15: FEI Average Speed of Answer (2014 – 2018) in seconds

Description	2014	2015	2016	2017	2018
Combined	34.05	36.70	39.62	33.97	35.23
Emergency	11.64	8.46	8.32	8.75	7.46
Non-Emergency	35.62	38.91	42.52	36.49	37.58

88.1 Please provide details of FEI's internal targets for the ASA. As part of this response, please discuss whether the results provided in Table A:C5-1-15 meet the targets.

Response:

FEI has not set an internal target for Average Speed of Answer (ASA) as this is an informational indicator that supports the TSF. FEI has used ASA to support the monitoring of TSF, providing further analysis of trends and outcomes of TSF, rather than regarding ASA as a standalone metric with its own target. The 2018 results for ASA were consistent with prior years, with the combined average emergency and non-emergency ASA being less than 40 seconds year over year.

88.2 Please explain whether, as part of its jurisdictional review, FEI identified the use of ASA as an SQI in any other jurisdiction.

Response:

The jurisdictional review did not include ASA. This is because ASA was considered in the context of an informational indicator and was not contemplated as an indicator with thresholds and benchmarks for the reasons discussed in the response to BCUC IR 1.88.3.

88.2.1 If yes, please provide details of the ASA used in other jurisdictions and provide a table comparing FEI's ASA for 2014 to 2018 against the ASA of other utilities identified in the jurisdictional review.

Response:

Please refer to the response to BCUC IR 1.88.2.

88.3 Please explain why FEI proposes that the ASA be an Informational Indicator as opposed to an Indicator with Benchmarks and Thresholds.

Response:

FEI and FBC have proposed ASA as an Informational Indicator as opposed to an indicator with benchmarks and thresholds for several reasons:

- The existing suite of indicators with benchmarks and thresholds have worked well and provide a good indication of the ability of FEI and FBC to be responsive to customer needs. As such, there is no need to expand with additional indicators. More specifically, the contact centre sites are managed and resourced to meet TSF and First Contact Resolution (FCR) targets. TSF and FCR combined together provide a holistic measure of service quality achieved within the contact centres.
- The Companies considered ASA in the context of being a replacement for an existing informational indicator. The ASA is proposed to be a replacement for the Telephone Abandonment Rate because it addresses some of the challenges and limitations of the Telephone Abandonment Rate.
- ASA is a complimentary informational indicator to the TSF and is used as such within the contact centres. ASA and TSF are both time-based indicators and determined from the same pool of data; however, while ASA provides a picture of the average speed of answer, the TSF provides a measure of service quality for the vast majority of customers (i.e. 70% of customers experience their calls answered within 30 seconds or less). Thus, ASA would be duplicative, have limited value, and require additional context as a stand-alone indicator with thresholds and benchmarks.

88.4 Please explain how the ASA is measured. As part of this response, please discuss whether FEI uses call menus, whether the ASA is measured once a customer is placed in a specific queue and what constitutes an "answer" (i.e. must a phone call be answered by a person or is it considered answered if an automated message is received).

Response:

ASA measures the time it takes for a customer to speak to a Customer Service Representative (CSR) after they select a menu option in the IVR, and are placed in a specific queue. ASA is calculated by the sum of the total time a caller waits for a CSR to pick up their call in the Emergency or Non-Emergency queues divided by the total number of calls that were answered by CSRs in those queues.

A call is considered to be answered when a customer is connected with a CSR. If a caller receives an automated message such as a callback offer, it will not be considered answered until it reaches a CSR.

On page 149 of the FEI PBR Decision, the BCUC stated that it "considers [the Telephone Abandonment Rate] to be a useful measure in determining the level of service failure."

88.5 Please explain whether FEI believes that the ASA SQI will be a useful measure in determining the level of service failure, and if yes, please explain how. If no, please explain how FEI will determine the level of service failure in the absence of the Telephone Abandonment Rate SQI.

Response:

For the purpose of this response, FEI has interpreted service failure to refer to a situation where the TSF has not been met.

FEI believes that ASA provides complimentary information to the TSF and because of this will provide additional insight on the 30 percent of calls that are not answered in thirty seconds or less (for non-emergency). For example, the TSF could be achieved, but year over year the

average speed of answer may be increasing. This would indicate that the average wait times for 30 percent of the calls are increasing.

However, a customer abandoning a call or average wait times increasing cannot automatically be considered service failures. For example, a customer may abandon a call for several reasons, one of which being that they received the information they were looking for through the IVR. In addition, a customer may experience slightly longer wait times than average but may still receive service in a prompt manner and have their concern resolved.

88.6 Please confirm, or explain otherwise, whether FEI will continue to record the Telephone Abandonment Rate.

Response:

Yes, FortisBC will continue to monitor and record the Telephone Abandonment Rate.

88.6.1 If confirmed, please explain whether FEI would be amenable to continuing to report the Telephone Abandonment Rate during the proposed MRP term.

Response:

FortisBC will continue to monitor Telephone Abandonment Rate, but will not report on it, as the Company believes ASA provides better information with respect to the overall level of service quality as compared to the Telephone Abandonment Rate and is a suitable replacement as an informational indicator.

89.0 Reference: FEI PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1, Section A1.3, p. A-12; Section C7.2, p. C-150

Greenhouse Gas (GHG) Emissions

On page C-150 of the Application, FortisBC states the following:

> 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 has proposed its inclusion in the Targeted Incentives section (see Section C8 Incentives). Additionally, the Companies recently published a new Sustainability Report which will be published annually, and includes GHG emissions information. The 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.

On page A-12 of the Application, FortisBC states the following:

> 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.

89.1 Please discuss whether, in light of FEI's proposed Clean Growth Innovation Fund, FEI would consider it appropriate to adopt SQIs to assess the fund's performance. Please explain why or why not.

Response:

As discussed in the responses to BCUC IRs 1.80.1 and 1.80.2.2, using service quality metrics to assess performance would not be well suited for the proposed Clean Growth Innovation

Fund. The initiatives and technologies being contemplated under the Fund are diverse and will be at different stages of research and development. Given their evolving nature and uncertainty, establishing appropriate benchmarks and targets would be challenging. While it may be possible to measure leading indicators of success in terms of completing projects on time, on budget and within scope, further lagging criteria could not be established on a broad basis in advance.

Instead of relying on performance metrics to gauge performance, FortisBC is proposing a governance structure including a Working Group, Executive Steering Committee and the External Advisory Council; a disciplined Project Development process; along with annual reporting that will be used to manage the overall performance of the Fund.

FortisBC also notes that the purpose of the SQIs in an MRP is quite different than the Innovation Fund.

89.1.1 Please outline the potential SQIs and metrics that could be used to assess the fund's performance.

Response:

Please refer to the response to BCUC IR 1.89.1.

90.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1, Section C7.3, p. C-151; Exhibit B-1-1, Appendix C5-2, pp. 1–2

Choice of Benchmarks

On pages 1 and 2 of Appendix C5-2, FortisBC states the following:

> Benchmarks are reference points against which levels of service quality can be compared. The objective of SQIs is to ensure that FBC continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. Therefore, in setting SQI benchmarks, it is necessary to consider whether customers are willing to pay for additional improvements in the indicators, as incremental costs for achieving further improvements increase as the limit of the indicator is approached. Benchmarks typically reflect either industry standards or the Company's performance over recent prior periods.

90.1 Please describe the industry standards which the proposed SQIs are benchmarked against and provide any benchmark or thresholds used by other utilities/jurisdictions.

Response:

Many of the SQIs proposed for FBC are the same as in the Current PBR Plan. As a result, FBC's approach in reviewing the appropriateness of the SQIs benchmarks and thresholds was focused on reviewing the metrics' performance during the Current PBR Plan to determine if updates to the benchmarks/thresholds were necessary. As FBC's recent performance would be a better measure of an acceptable level of service at an acceptable level of cost to our customers, there was limited benchmarking of metrics compared to industry standards.

The only SQI where there was a comparison to industry standards performed was in support of the FCR where FBC confirmed that its FCR performance remained considerably above the industry's performance for energy call centre reported at 70% for 2018.

FBC believes it is appropriate to base the proposed benchmarks on performance in recent years rather than comparing to general industry standards because the benchmarks are then reflective of the costs required by FBC provide the service levels. This is consistent with the BCUC's decision for the Current PBR Plan where the BCUC determined that setting the benchmark based on the last three-year period establishes the benchmark at a level that is reflective of the costs required to provide the level of service.

On page C-151 of the Application, FBC provides the current and proposed SQIs in Table C7-5.

90.2 Please discuss whether, in the event that a sustained under-investment resulting in serious degradation of service levels occurred, the impact of such an occurrence would likely be uncovered during the five-year MRP term through a decrease in SQI performance. Please specifically consider impacts to SAIDI and SAIFI in this response.

Response:

A sustained under-investment resulting in serious degradation of service levels would likely have a negative impact on both SAIDI and SAIFI during the five-year MRP term. Reducing or eliminating investment in sustainment programs (such as Condition Assessments, Line Rehabilitations, Right of Way maintenance, etc.) would lead to an increasing rate of equipment-related failures and tree contact events. The end result would be an increase in both SAIDI and SAIFI. The overall impact would depend on both the magnitude and duration of under investment, but would likely have a measurable impact during the five-year MRP term. To mitigate against this, FBC has a number of sustainment programs that support the ongoing safety and reliability of the electric system. As such, FBC does not envision that such a scenario will arise.

90.2.1 If no, please discuss the likely length of time that a sustained under-investment would need to persist to affect a marked decrease in SQI performance.

Response:

Please refer to the response in BCUC IR 1.90.2.

90.2.2 If a marked decrease in SQI performance would not likely be seen for a period of time longer than five years, please discuss the importance of consistency in which SQIs are reported over many PBR/MRP terms in

order to identify trends. Please also comment on how changing SQIs would affect the ability to identify trends.

Response:

Where the impact of any change in investment strategies or operating practices may not be fully realized over a single PBR/MRP term, it is important to maintain consistency in which SQIs are reported in order to identify longer-term trends against an established baseline of performance. For example, changing the methodology used to calculate the reported results for a metric will make it difficult to detect any trends in performance, as the results would no longer be an "apples to apples" comparison.

A recent example of this would be regarding the results reported for the reliability SQIs, SAIDI and SAIFI. The implementation of the Outage Management System in 2017 affected the way that outage data is tracked through an automated system and contributed to higher values being reported. As a result of this change to how SAIDI and SAIFI are being reported, FBC believes it is important to use a sufficient period of time (3 year average) where the results are on an "apples to apples" basis in order to determine appropriate benchmarks.

Additionally, consistency in the choice of SQIs is important to enable the identification of trends in the performance of individual metrics and the overall service level provided for customers. Any change in the choice of the SQIs can present a challenge to identifying trends over multiple PBR/MRP terms. FBC recognizes, though, there may be a need to add or replace SQIs as circumstances changes over time. An example of this is the proposed addition of the new informational Interconnection Utilization metric in response to concerns expressed by FBC's Wholesale Municipal customers concerning the reliability of the system.

90.3 Please explain whether FBC considered any other SQI indicators other than those discussed in the Application.

Response:

Please refer to FEI's response to BCUC IR 1.84.6, which applies equally to FBC.

90.4 Please discuss whether, in its review of the existing SQIs, FBC considered adopting any new SQIs other than those discussed in the Application.

Response:

Please refer to the response to BCUC IR 1.90.3.

90.4.1 If yes, please provide details of any SQIs considered and the reasons for their ultimate rejection.

Response:

Please refer to the response to BCUC IR 1.90.3.

90.4.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.90.3.

90.5 Please explain whether, as part of FBC's review of the SQI selection criteria, FBC considered adjusting or adopting new criteria as a result of the information gathered as part of the jurisdictional review performed in Appendix C4-2.

Response:

Please refer to the response to BCUC IR 1.85.1.

90.5.1 If yes, please discuss the items considered and provide reasons for their ultimate rejection.

Response:

Please refer to the response to BCUC IR 1.85.1.

90.5.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.85.1.

90.6 Please explain whether FBC identified the SQIs used for any of the jurisdictions reviewed and, if yes, please provide a summary of the SQIs for each applicable jurisdiction and discuss whether FBC considered adopting any of the SQIs identified.

Response:

Please refer to the response to BCUC IR 1.85.1.

90.6.1 For any SQIs common to FBC and other jurisdictions identified in the jurisdictional review, please provide a table comparing FBC's SQI results and those of the other utilities. Please comment on FBC's results compared to other utilities.

Response:

Please refer to the response to BCUC IR 1.85.1.

90.7 Please provide a table showing the historical SQI performance and benchmark and threshold levels during the Current PBR Plan term for each SQI and informational indicator.

Response:

Please see the table below showing the historical SQI performance and benchmark and threshold levels during the Current PBR Plan term for each SQI and informational indicator.

1

Indicators with Benchmarks and Thresholds		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold	*2014* Results	*2015* Results	*2016* Results	*2017* Results	*2018* Results
Safety	**Emergency Response Time** - Calls responded to within two hours	>= 93%	90.6%	>=93%	90.6%	91%	92%	97%	93%	94%
Safety	**All Injury Frequency Rate**	<=1.64	2.39	<=1.64	2.39	2.58	2.52	1.97	1.27	1.28
Responsiveness to Customer Needs	**First Contact Resolution**	>= 78%	72%	>=78%	74%	73%	76%	79%	80%	82%
Responsiveness to Customer Needs	**Billing Index**	<= 5	<=5	<=3	5	2.34	0.39	0.57	0.15	0.29
Responsiveness to Customer Needs	**Meter Reading Accuracy** - Number of scheduled meter reads that were read	>= 97%	94%	>=98%	95%	98%	96%	99%	99%	99%
Responsiveness to Customer Needs	**Telephone Service Factor** - Calls answered in 30 seconds or less	>= 70%	68%	>=70%	68%	48%	71%	70%	70%	72%
Reliability	**System Average Interruption Duration Index - Normalized**	<= 2.22	2.62	TBD	TBD	2.09	2.15	2.18	2.76	3.10
Reliability	**System Average Interruption Frequency Index - Normalized**	<= 1.64	2.50	TBD	TBD	1.39	1.49	1.51	1.56	1.62
Informational Indicators										
Responsiveness to Customer Needs	**Customer Satisfaction Index**	n/a	n/a	n/a	n/a	8.1	8.1	8.2	8.2	8.3
Responsiveness to Customer Needs	**Average Speed of Answer in seconds (replaces Telephone Abandonment Rate)**	n/a	n/a	n/a	n/a	225.78	49.07	48.48	48.71	48.64
Reliability	**Generator Forced Outage Rate**	n/a	n/a	n/a	n/a	1.7%	0.1%	0.8%	0.6%	0.4%
Reliability	**Interconnection Utilization**	n/a	n/a	n/a	n/a	99.99%	99.94%	99.99%	99.95%	99.96%
Eliminated	**Telephone Abandonment Rate (replaced by Average Speed of Answer)**	n/a	n/a	n/a	n/a	12.4%	2.7%	3.9%	4.7%	5.3%

2

3

90.8 Please explain the implications under the proposed MRP to FBC and to ratepayers if one or more of FBC's SQIs fall below the indicated benchmark. Please compare these implications to the Current PBR Plan.

Response:

FBC is proposing no changes to the existing approved process for interpreting metric performance that exists in the Current PBR Plan where performance for one or more of FBC's SQIs do not meet the benchmark and fall outside of the threshold. The process that introduced the use of SQI performance ranges for interpreting metric performance is outlined in the agreement titled the "Consensus Recommendation" approved by the BCUC in Order G-14-15 dated February 4, 2015[131].

Also, similar to the Current PBR Plan, 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 FBC, may result in a reduction to the share of earnings sharing retained by FBC, 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 FBC), instead of the standard 50 percent.

90.9 Please explain the implications under the proposed MRP to FBC and to ratepayers if one or more of FBC's SQIs fall below the indicated threshold. Please compare these implications to the Current PBR Plan.

Response:

Please refer to the response to BCUC IR 1.90.8.

[131] https://www.ordersdecisions.bcuc.com/bcuc/orders/en/119407/1/document.do.

91.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C5-2, pp. 7–8

Billing Index

On page 8 of Appendix C5-2, FortisBC describes the Billing Index in Tables A:C5-2-7 and A:C5-2-6.

FortisBC further states the following on page 8 of Appendix C5-2: "Reflective of the recent historical performance and efficiencies achieved by the Company in producing bills, FBC proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0."

91.1 Considering the results achieved during the Current PBR Plan term, please explain whether it would be appropriate to adjust the Benchmark and Threshold values for the Billing Index even lower than the values proposed in this Application.

Response:

FBC believes that the Benchmark and Threshold values for the Billing Index are appropriate as proposed in the Application.

The proposed benchmark and threshold levels take into consideration that there are a combination of factors reflected in the index, which may create larger fluctuations if issues occur even if they may be relatively minor. For example, a weather event or unplanned information system outage may cause unexpected impacts to billing processes.

In addition, the proposals are consistent with FEI and reflect that all customers should have similar experiences with respect to billing services. Finally, the proposed levels reflect a high level of service quality overall with a benchmark of 3 equating to 97 percent of bills delivered within 2 days to Canada Post, 97 percent of customers billed within two business days of the scheduled billing date, and 99.95 percent of bills completed accurately.

92.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C5-2, p. 9

Meter Reading Accuracy

On page 9 of Appendix C5-2, FortisBC states the following:

> This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:
>
> $$\frac{\text{Number of meters read}}{\text{Number of scheduled meters for reading}}$$

92.1 Please explain how many meters are read in-person and how many are read remotely electronically.

Response:

Approximately 3 percent of FBC's meters are read in-person and 97 percent are read electronically.

92.1.1 Please explain why remote electronic meter reading performance is considered valid as an SQI. As part of this response, please clarify why remote electronic meter reading would not have 100 percent scheduling performance and 100 percent accuracy.

Response:

FBC considers remote electronic meter reading to be a valid SQI.

Automatic meter reading does not have 100% performance and accuracy for several reasons. For example, some customers still request manual reads, and some meters are radio-off by design due to their location that does not allow for a proper signal to be sent into the FBC system. In addition, failures can occur due to weather or system issues.

Having a target that tracks these instances ensures that FBC is accountable for obtaining meter readings in both manual and automatic reading situations.

92.1.2 Please explain if other Canadian utilities with smart meters use meter reading performance as an SQI.

Response:

The following examples describe the use of metrics of a similar nature to FBC's Meter Reading Accuracy measure, in Alberta, Ontario and for BC Hydro in BC.

Alberta

In Alberta, both electric distribution and gas utilities operate under PBR regimes and have an SQI reporting framework set out in the AUC's Rule 002 (Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors)[132]. The AUC's Rule 002 sets out quarterly and annual SQI reporting requirements and includes, among a series of other SQIs, meter reading metrics for both electric distribution and gas utilities. The meter reading metric(s) for electric distribution utilities are described in section 4.1 of Rule 002, with subsection 4.1.1 being the most similar to FBC's proposed metric. Some, but not all, of Alberta electric distribution utilities have AMI. EPCOR and Fortis Alberta are examples of electric distribution utilities that have AMI.

Ontario

Ontario's electric distribution utilities (66 utilities in 2017) are all operating under PBR (the OEB 4th Generation IR framework) and have to track their results annually using a scorecard of 20+ measures (as mandated by the OEB[133]). Smart meters were mandated by the Ontario government and have been in place across the province a number of years. The OEB scorecard includes a "Billing Accuracy" metric but not a specific meter reading metric.

British Columbia - BC Hydro

Although BC Hydro has full AMI deployment, it is not operating under a PBR regime.

Regarding a measure of meter reading performance, BC Hydro makes the following statement at page 5F-34 of its F2020-F2021 Revenue Requirement Application:

> BC Hydro's meter reading performance targets are to issue at least 99 per cent of bills using actual meter readings and to issue no more than 0.5 per cent of bills on billing system estimates for consecutive billing periods. These metrics are

[132] AUC Rule 002: http://www.auc.ab.ca/regulatory_documents/Consultations/2015-01-01-Rule002.pdf.
[133] OEB Scorecard - Performance Measure Descriptions – see page 2 for Billing Accuracy measure https://www.oeb.ca/oeb/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf.

generally comparable to FortisBC's approved Service Quality Indicator of Meter Reading Accuracy of 97 per cent.

Although BC Hydro does not propose, if placed on a PBR regime by the BCUC, to adopt a similar meter reading performance metric to FBC's Meter Reading Accuracy measure[134], their use of a similar metric for internal performance targets suggests there is value in the measure.

[134] BC Hydro F2020-F2021 Revenue Requirement Application, page 11-57.

93.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C5-2, pp. 11–12

Telephone Abandonment Rate

On page 11 of Appendix C5-2, FortisBC provides the following table:

Table A:C5-2-11: Results during the PBR for Telephone Abandonment Rate

Description	2014	2015	2016	2017	2018
Telephone Abandonment Rate	12.4%	2.7%	3.9%	4.7%	5.3%

Further on page 11 of Appendix C5-2, FortisBC states: "FBC proposes to replace the existing metric with another Informational Indicator, Average Speed of Answer (ASA)."

On page 12 of Appendix C5-2, FortisBC provides the following table:

Table A:C5-2-12: FBC Results during the PBR Plan for Average Speed of Answer (in seconds)

Description	2014	2015	2016	2017	2018
Average Speed of Answer	225.78	49.07	48.48	48.71	48.64

93.1 Please explain how the telephone abandonment rate is determined.

Response:

The Telephone Abandon Rate is calculated by the number of calls abandoned by the customer before speaking to a customer service representative divided by the total calls received.

93.2 Please explain whether FBC considered keeping the Telephone Abandonment Rate and adding the Average Speed of Answer SQI.

Response:

The Companies do not consider that it would be reasonable to keep the Telephone Abandonment Rate and add the ASA informational SQI. As discussed on pages 11-12 of

Appendix C5-2, it is not possible to know with certainty what trends the Telephone Abandonment Rate relate to. It therefore should not be kept as an informational SQI. Please also refer to the response to BCUC IR 1.88.3, for further discussion of why FBC is proposing to replace the Telephone Abandonment Rate with ASA.

93.3 Please provide details on FBC's internal targets for the ASA. As part of this response, please discuss whether the results provided in Table A:C5-2-12 meet the targets.

Response:

In the past, FBC has not set an internal target for ASA as this is an informational indicator that supports the TSF. That is, FBC has used ASA to support the monitoring of TSF, providing further analysis of trends and outcomes of TSF, rather than regarding ASA as a standalone metric with its own target.

The 2018 results for ASA were consistent with prior years with the average ASA being less than 50 seconds year over year. ASA for 2014 was impacted by labour disruption.

93.4 Please explain whether, as part of its jurisdictional review, FBC identified the use of ASA as an SQI in any other jurisdiction.

Response:

Please refer to the response to BCUC IR 1.88.2.

93.4.1 If yes, please provide details of the ASA used in other jurisdictions and provide a table comparing FBC's ASA for 2014 to 2018 against the ASA of other utilities identified in the jurisdictional review.

Response:

Please refer to the response to BCUC IR 1.88.2.

93.5 Please explain why FBC proposes that the ASA be an Informational Indicator as opposed to an SQI with Benchmarks and Thresholds.

Response:

Please refer to the response to BCUC IR 1.88.3.

93.6 Please explain how the ASA is measured. As part of this response, please discuss whether FBC uses call menus, whether the ASA is measured once a customer is placed in a specific queue and what constitutes an "answer" (i.e. must a phone call be answered by a person or is it considered answered if an automated message is received).

Response:

Please refer to the response to BCUC IR 1.88.4.

93.7 Please explain whether FBC believes that the ASA SQI will be a useful measure in determining the level of service failure, and if yes, please explain how. If no, please explain how FBC will determine the level of service failure in the absence of the Telephone Abandonment Rate SQI.

Response:

Please refer to the response to BCUC IR 1.88.5.

93.8 Please confirm, or explain otherwise, whether FBC will continue to record the Telephone Abandonment Rate.

Response:

Please refer to the response to BCUC IR 1.88.6.

93.8.1 If confirmed, please explain whether FBC would be amenable to continuing to report the Telephone Abandonment Rate during the proposed MRP period.

Response:

Please refer to the response to BCUC IR 1.88.6.1.

FBC will continue to monitor the Telephone Abandonment Rate, but will not report on it as FBC believes ASA provides better information with respect to the overall level of service quality as compared to the Telephone Abandonment Rate and is a suitable replacement as an informational indicator.

94.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C5-2, pp. 12–14

Reliability SQIs

On page 12 of Appendix C5-2, FortisBC states the following:

> FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronic Engineers (IEEE) method of normalizing reliability statistics by excluding "major events"….. Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

94.1 Please explain how the SAIDI and SAIFI SQIs would differ if all major outages were added to the calculation, instead of only outages one minute or longer in duration.

Response:

Consistent with common utility practice in Canada, FBC's reliability statistics include all outages one minute or longer. In reporting its SQIs, FBC also excludes outages resulting from major events, which are defined by IEEE as those exceeding the 2.5 Beta threshold, and is a common method of normalizing system outages. FBC does not consider momentary outages (less than one minute in duration) to be major outages.

If FBC reported non-normalized statistics by including outages that qualify as "major events", both indices would increase depending on the frequency and severity of the major events in any given year.

94.1.1 Please explain the pros and cons of reporting SAIDI and SAIFI with major outages included and whether such a change would be appropriate.

Response:

All major outages that qualify as "major events" are currently collected and studied separately by FBC. This is used to help inform decisions around design practices and to improve operational response during these events.

The main benefit of removing major events from the reported SAIDI and SAIFI values is that it provides more stability in the data and allows FBC to focus investment decisions and operating practices in areas that most benefit "normalized" customer reliability.

If major events were included in the reported values they would introduce a greater amount of variability from year to year for the reported SAIDI and SAIFI values. This would make it increasingly difficult to measure the quality of service provided by FBC as it relates to reliability. Major events are primarily driven by severe weather, forest fires, etc. that occur in random locations that are outside the control of FBC and that may not reflect year over year performance.

Given the above, FBC does not believe a change in reporting for SAIDI and SAIFI is appropriate.

94.2 Please explain how the SAIDI and SAIFI SQIs would differ if outages less than one minute in duration were added to the calculation.

Response:

Both SAIDI and SAIFI indices would increase to some degree if outages less than one minute were added to the calculation. These interruptions are typically restored by an automatic reclosing device and are of very short duration (five to fifteen seconds).

FBC has not historically tracked this data so is unable to quantify what the impact would be to the SAIDI and SAIFI values. However, FBC believes the impact would be relatively minor.

94.2.1 Please explain the pros and cons of reporting SAIDI and SAIFI with outages less than one minutes in duration included and whether such a change would be appropriate.

Response:

Momentary outages were not tracked historically since often these outages went unreported by customers. With the implementation of the AMI and the ADMS systems, FBC now has the ability to track and report on these outages without relying on customer feedback.

Since the overall impact is somewhat unknown and provides limited value, FBC does not believe a change in reporting is appropriate.

On page 13 of Appendix C5-2, FortisBC states the following regarding SAIDI results:

> Starting in 2017 and in 2018, the results have been influenced by the implementation of the Outage Management System (OMS), a system used to record distribution outages based on the outage start time. The OMS replaced a manual system and has automated the tracking and reporting of outage data through integration with the FBC AMI system….With the change in OMS and a different definition to the outage start time, the reported outage times have increased, causing SAIDI values reported to increase, even though there has been no change in the Company's operating practices….To adjust for the influence of the OMS on the higher SAIDI results reported, FBC proposes to update the existing SAIDI three year rolling average benchmark. For the next MRP, starting 2020, FBC will have three full years of SAIDI results available (i.e. 2017, 2018, 2019) incorporating the impact of the OMS. As the 2019 SAIDI results will not be available until early 2020, FBC will be providing the proposed benchmark based on a three year rolling average and the threshold for the next MRP in early 2020.

94.3 Please explain whether FBC considered using any other benchmarking methods for reporting on SAIDI. For example, reporting using a five-year average, two-year average, or annual results (i.e. not averaged).

Response:

FBC did not consider other benchmarking methods for reporting on SAIDI and notes that the proposed method to determine a benchmark for SAIDI based on a three-year average of results is consistent with the BCUC's determination at page 149 of the FBC 2014-2018 PBR Decision, as follows:

> The Panel agrees with BPCSO that setting the benchmark based on the last three-year period for which annual data was available (2010, 2011 and 2012) establishes the benchmark at a level that is reflective of the costs required to provide this level of service.

FBC believes the existing three-year average approach to determining the SAIDI benchmark continues to be appropriate and as a result did not consider other methods for determining the appropriate SAIDI benchmark to use.

As outlined in Appendix C5-2 page 13, line 29, for reporting of the actual results, FBC has proposed to revise the basis from the current three-year rolling average approach to a current year only approach. A current year results focus is a clearer indicator of the Company's performance in a given year than one based on a three year rolling average. Additionally, a current year results focus is generally easier to understand.

94.4 Please provide FBC's two-year average SAIDI results for 2017-2018.

Response:

Provided below are the annual results for the requested period along with the calculated two-year average for 2017-2018.

Service Quality Indicator		2017 Actual	2018 Actual
Annual	System Average Interruption Duration Index - Normalized	4.05	3.15
2 Year	System Average Interruption Duration Index - Normalized	N/A	3.60

94.4.1 Please explain whether FBC would consider using this result as a benchmark for the proposed MRP.

Response:

For consistency with how previous benchmarks were set, FBC prefers to wait for the 2019 year-end SAIDI result and move forward at that time with a benchmark calculated based on a three-year rolling average. Given the timing of a decision in this proceeding, waiting for the 2019 year-end SAIDI results will not introduce any lag into the process.

94.4.2 Please explain whether FBC would consider using a two-year rolling average result for the first year of the proposed MRP, then revert to a three-year rolling average for the subsequent years of the MRP term.

Response:

FBC is unclear of the benefit to establishing a benchmark for the year 2020 based on a two-year average instead of waiting to the end of 2019 to calculate a benchmark based on a three-year average using 2017, 2018 and 2019 annual results. For consistency in the interpretation of results, FBC prefers to use a three-year rolling average based on 2017, 2018 and 2019 annual results to establish the SAIDI benchmark to use during the MRP term. There is no reason to adopt a two-year approach for one year and then move back to a three-year approach.

On page 14 of Appendix C5-2, FortisBC states the following regarding SAIFI results:

> From 2014 to 2018, the results have been better than the benchmark. Similar to SAIDI, the SAIFI results in 2017 and 2018 have been influenced by the implementation of the OMS, although to a lesser degree….To adjust for the influence of the OMS on the higher SAIFI results reported, FBC proposed to update the existing SAIFI three year rolling average benchmark. For the next MRP, starting 2020, FBC will have three full years of SAIFI results available (i.e., 2017, 2018, 2019) incorporating the impact of the OMS. As the 2019 SAIFI results will not be available until early 2020, FBC will be providing the proposed benchmark based on a three year rolling average and the threshold for the next MRP in early 2020. In addition, FBC proposes to revise the basis for the actual results reported from the current three-year rolling average approach to a current year only approach. A current year results focus approach is a clearer indicator of the Company's performance in a given year than one based on a three year rolling average. Additionally, a current year results focus is generally easier to understand.

94.5 Please explain why FBC is proposing to wait for the 2019 SAIFI results to compose its three-year average for the benchmark, given its statement that moving to the OMS has not had much influence on SAIFI results.

Response:

To clarify, FBC stated on page 14 of Appendix C5-2 that "…SAIFI results in 2017 and 2018 have been influenced by the implementation of the OMS, although to a lesser degree" should be interpreted the same as "…both the 2017 annual and 2018 year to date SAIFI results have been influenced, although to a lesser degree, by the implementation of the OMS".

FBC believes that there has been an impact to SAIFI from the implementation of the OMS, just to a lesser degree relative to SAIDI. Given this, FBC believes it is prudent to delay setting a new SAIFI benchmark, similar to that proposed for SAIDI, until the 2019 year-end results are available.

94.5.1 Please explain whether FortisBC would consider calculating its benchmark three-year average using the results from 2016, 2017 and 2018.

Response:

FBC would prefer to wait until the 2019 year-end SAIFI results are available to establish the new benchmark using three years of data (2017, 2018 and 2019) following implementation of the OMS, for the same reasons as discussed in the BCUC 1.94.4 series of responses regarding SAIDI.

94.5.2 Please provide the three-year average SAIFI results for 2016 through 2018.

Response:

Provided in the table below are the 2016 to 2018 annual SAIFI results along with the three-year average SAIFI result of 1.62 based on 2016 through 2018 annual results.

Service Quality Indicator		2016 Actual	2017 Actual	2018 Actual
Annual	System Average Interruption Frequency Index - Normalized	1.34	1.78	1.73
3 Year	System Average Interruption Frequency Index - Normalized	N/A	N/A	1.62

94.5.3 Please provide the two-year average SAIFI results for 2017 and 2018.

Response:

Provided below are the annual results for the requested period along with the calculated 2 year average for 2017-2018.

Service Quality Indicator		2017 Actual	2018 Actual
Annual	System Average Interruption Frequency Index - Normalized	1.78	1.73
2 Year	System Average Interruption Frequency Index - Normalized	N/A	1.76

The two-year average SAIFI result for 2017 and 2018 is 1.76.

95.0 Reference: FBC PROPOSED SERVICE QUALITY INDICATORS

Exhibit B-1-1, Appendix C5-2, pp. 15–16

Municipal Wholesale Customers Service Quality

On page 15 of Appendix C5-2, FortisBC states the following:

> In response to concerns brought forward by the BCMEU that the SQIs were not prepared in contemplation of the specific concerns of wholesale customers, FBC proposes to establish a new informational service quality indicator to monitor the level of service provided to the municipal wholesale customers (i.e. City of Penticton, City of Summerland, City of Grand Forks and City of Nelson).
>
> The new metric, "Interconnection Utilization", is a measurement of the time that an interconnection point was available and providing electrical service to these customers. There are twelve points of interconnection combined between the four customers as shown in the table below:

Table A:C5-2-15: Interconnection Points

Customer	Point of Interconnection
City of Nelson	Rosemont Substation
	Coffee Creek Substation
City of Penticton	Huth Avenue Substation (13kV)
	Huth Avenue Substation (8kV)
	Waterford Substation
	Westminister Substation
	R.G. Anderson Substation
City of Summerland	Summerland Substation
	Trout Creek Substation
City of Grand Forks	Ruckles Substation (DB1)
	Ruckles Substation (DB2)
	Donaldson Drive

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

Further on page 16 of Appendix C5-2, FBC provides the following table summarizing the historical results for Interconnection Utilization since the start of the Current PBR Plan term:

Table A:C5-2-16: Results during the PBR Plan for Interconnection Utilization

Description	2014	2015	2016	2017	2018
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%

FortisBC states the following on page 16 of Appendix C5-2:

> As an example of the calculation shown above for 2018, these interconnection points were providing service for 105,082 hours out of the available 105,120 hours, at an Interconnection Utilization performance level of 99.96 percent. From 2014 to 2018, the results have been stable from year to year.

95.1 Please explain whether FBC considered any other reporting mechanisms as an SQI for the reliability of its interconnections to its wholesale customers. If yes, please explain why these other mechanisms were ultimately rejected. If no, please explain why not.

Response:

FBC considered providing other metrics such as SAIDI and SAIFI specific to the Municipal Wholesale customers, but this was rejected due to a lack of access to historical customer counts for the interconnections required for the calculation. The Interconnection Utilization metric was chosen because it is simple, easy to understand, and the data required was readily available.

95.2 Please explain what level of Interconnection Utilization FBC is (i) contractually obligated to provide and (ii) what level FBC considers as acceptable to provide to its wholesale customers.

Response:

Regarding standards of performance, FBC's agreements with the various wholesale customers generally state the following:

> …FortisBC shall perform the Services with skill, care and diligence consistent with Good Utility Practice and consistent with directions from the Commission,

including the quality performance standards, if any, approved by the Commission from time to time…

FBC strives for the same high level of service to each of its customers, regardless of whether they are wholesale or direct.

95.3 Please explain FBC's wholesale customers' level of satisfaction with the Total Outage Time they currently experience on their interconnections.

Response:

To the best of FBC's knowledge, wholesale customers are satisfied with the reliability of the interconnections. The one exception is Nelson Hydro's interconnection at Coffee Creek substation.

Both Nelson Hydro and FBC customers have raised concerns regarding the reliability of supply along the east and west shore of Kootenay Lake. FBC has completed a number of initiatives aimed at increasing the reliability of supply in the region and is currently evaluating other options.

95.4 Please explain what steps FBC could take to improve the Interconnection Utilization statistics.

Response:

FBC regularly reviews its reliability performance for both our direct and wholesale customers and prioritizes system upgrades accordingly. Specifically, the City of Nelson has raised concerns with the reliability at its point of supply at Coffee Creek in the Kootenay Lake region. This substation is primarily served by 30 Line, which is operated as a radial feed and is routed through remote and rugged terrain and which is subject to outages due to severe weather and contacts from trees outside of the right of way. FBC has completed, or is in the process of completing, several upgrades to address these concerns, including the 30 Line Rehabilitation Project shown in Table C3-32 and improvements to the 30 Line right of way included in Table C3-33. FBC is also in the process of evaluating future options meant to improve the reliability of the supply to the region.

95.5 Please provide, in a table similar to Table A:C5-2-16, the total outage time for each of the 12 interconnection points listed in Table A:C5-2-15 for the years 2014 through 2018.

Response:

Please see the table below for the total outage time in hours for each of the twelve interconnection points listed in Table A:C5-2-15 for the years 2014 through 2018. Overall, the reliability performance has been strong with the exception of Coffee Creek.

As stated in BCUC IR 1.95.4, the Coffee Creek substation is primarily served by 30 Line, which is operated as a radial feed and is routed through remote and rugged terrain and which is subject to outages due to severe weather and contacts from trees outside of the right of way. FBC has completed, or in the process of completing, several upgrades to address the concerns at Coffee Creek, including the 30 Line Rehabilitation Project shown in Table C3-32 and improvements to the 30 Line right of way included in Table C3-33. FBC is also in the process of evaluating future options meant to improve the reliability of the supply to the region.

The outages to the City of Grand Forks experienced in 2017/2018 were mainly driven by an equipment failure, third party interference where a forestry worker damaged a transmission line and the extreme flood event in May 2018. The City of Summerland also experienced an extended outage at Summerland and Trout Creek in 2018 due to a motor vehicle accident that damaged the transmission supply to those substations.

Customer	Point of Interconnection	2014	2015	2016	2017	2018
City of Nelson	Rosemont Substation	0.00	0.00	0.00	2.38	0.63
	Coffee Creek Substation	5.32	52.36	6.26	51.18	22.67
City of Penticton	Huth Avenue Substation (13kV)	0.00	0.00	0.00	0.00	0.00
	Huth Avenue Substation (8kV)	0.00	0.00	0.00	0.00	0.00
	Waterford Substation	0.00	0.00	2.13	0.00	0.00
	Westminister Substation	1.74	7.31	0.00	0.00	0.00
	R.G. Anderson Substation	0.00	0.00	0.90	0.00	0.00
City of Summerland	Summerland Substation	0.45	0.00	0.00	0.00	4.39
	Trout Creek Substation	0.81	0.00	0.00	0.00	1.36
City of Grand Forks	Ruckles Substation (DB1)	2.97	0.00	1.18	5.24	8.89
	Ruckles Substation (DB2)	2.97	0.00	1.18	5.24	8.89

Customer	Point of Interconnection	2014	2015	2016	2017	2018
	Donaldson Drive	4.05	0.00	0.00	0.00	3.52

95.6 Please explain whether the figure of 105,120 available hours is derived from the total number of hours in a year, times the number of connections (12). Please provide the total number of hours in a year used in FBC's calculation. As part of this response, please explain whether the annual total operating hours is adjusted for leap years.

Response:

Correct, the figure of 105,120 available hours is derived from the total number of hours in a year, times the number of interconnections (12). The total hours are adjusted for leap years such as 2016 where the available hours per interconnection increases from 8,760 hours to 8,784 hours.

I. INCENTIVES

96.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3, pp. C-157 – C-159; Exhibit B-1-1, Appendix C8, p. 2

Exhibit B-3, Workshop Presentation, Slide 31

Targeted Incentives

On page C-157 of the Application, FortisBC states the following:

> 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.

96.1 For each of the targeted incentives listed in Table C8-1 on page C-159 of the Application, please explain why pursuit of these targets is not part of FortisBC's regular business plan, and therefore already compensated by the approved rate of return.

Response:

The Targeted Incentives listed in Table C8-1 of the Application are not being compensated by the approved rate of return. The approved rate of return is based on the Fair Return Standard, the legal test applied to ensure that investors receive the opportunity cost on their investment represented by the rate of return investors could expect to earn elsewhere without bearing more risk. FortisBC's fair return is not based on carrying out a regular business plan; rather, under the Utilities Commission Act, the BCUC must approve rates that provide FEI and FBC a reasonable opportunity to earn a fair and reasonable return.

The Targeted Incentives FortisBC has proposed in its MRPs are a part of the ratemaking mechanism that is conceptually separate from the approved rate of return. The proposed MRPs are a form of performance or incentive ratemaking designed to provide incentives to the utilities to achieve certain objectives. As stated in Section 60 of the Utilities Commission Act, the BCUC must have due regard to setting a rate that "encourages public utilities to increase efficiency reduce costs and enhance performance" and "may use any mechanism, formula or other method of setting the rate that it considers advisable".

The level of performance embedded in each of the Targeted Incentives listed in Table C8-1 of the Application represents performance above and beyond conventional service and creates positive value for customers. In other words, the Targeted Incentives have been designed to create outcomes above what is normally expected in the regular course of business. It is just and reasonable for the BCUC to approve a ratemaking plan that includes such incentives as they encourage FEI and FBC to enhance their performance, will benefit customers, and are aligned with the public interest.

96.2 Please clarify whether the currently approved ROE and capital structures for FEI and FBC are still reflective of and aligned with the current "challenges and opportunities" that FEI and FBC face in their operating environments. Please respond separately for each of FEI and FBC.

Response:

For clarity, FEI and FBC have both proposed Targeted Incentives to expand their focus to addressing the emerging challenges and opportunities in their operating environments. The reward for achieving a Targeted Incentive has been proposed as an ROE adder for simplicity and transparency and is not necessarily related to utility risk.

The appropriateness of FEI and FBC's authorized ROE and capital structures is not addressed in this Application. Rather, their authorized ROE and capital structures are determined through separate cost of capital proceedings which would examine, among other things, the appropriate balance of risk and reward and financial market considerations. Any future cost of capital proceedings will take into account both the current rate making structure in place and other changes in the Utilities' operating environment in determining any required adjustments to the cost of capital.

Please also refer to the response to BCUC IR 1.29.3.

96.2.1 If yes, please explain why targeted ROE-based incentives are appropriate.

Response:

Please refer to the response to BCUC IR 1.96.2.

96.2.2 If no, please explain whether there are other regulatory options/processes to address this issue and, if so, why these other regulatory options/processes would not be more appropriate than the proposed approach of targeted incentives.

Response:

Please refer to the responses to BCUC IRs 1.29.3 and 1.96.2.

96.3 If the proposed targeted incentives were not approved, would FortisBC still pursue these targets? Please explain why or why not and address each incentive separately.

Response:

FortisBC would pursue each of the targets in the absence of approval in order to address the emerging challenges and opportunities in its operating environment. However, in the absence of approval of the Targeted Incentives, FortisBC would be less likely to achieve the targets or the same level of performance as it would with Targeted Incentives. This is due to the lack of an incentive to undertake the extraordinary efforts and investment of resources required to achieve these outcomes, the resulting shift in focus to traditional incentives and service quality, and the lack of BCUC endorsement of the targets as priorities to be addressed during the term the MRPs.

The table below provides further information on why the Utilities would pursue the Targeted Incentives in the absence of approval:

Company	Incentive	Pursue in the absence of approval?	Why / Why Not?
FEI	Growth in renewable gas	Yes	Aligned with climate policy, beneficial for customers and the utility, and is in the public interest.
	Growth in NGT	Yes	
	GHG Emissions Reductions (Customer)	Yes	

Company	Incentive	Pursue in the absence of approval?	Why / Why Not?
	GHG Emissions Reductions (Internal)	Yes	Aligned with climate policy, beneficial for customers, and is in the public interest.
	Customer Engagement	Yes	Beneficial for customers.
FBC	Customer Engagement	Yes	Beneficial for customers.
	Growth in Electric Vehicle Transportation	Yes	Aligned with climate policy, beneficial for customers and the utility, and is in the public interest.
	Power Supply Incentive	Yes	Beneficial for customers and is aligned with a focus on cost efficiency.

96.4 Is FortisBC aware of any Canadian peers who have similar incentives? If so, please list each utility/jurisdiction and describe the incentives, with supporting references where possible.

Response:

FortisBC is not aware of any other Canadian peer utilities who currently have similar targeted incentives mechanisms. Other jurisdiction, such as the U.K., California, New York, Illinois and Hawaii, however, are using targeted incentive mechanisms. The report in Appendix C8 of the Application, *Utility Performance Incentive Mechanisms, A Handbook for Regulators*, includes detailed case studies of the U.K., California and New York experiences. The report describes how regulators are turning to targeted incentive mechanisms to better align utility regulatory and financial incentives with the public interest, stating (at page 6):

> This report describes how regulators can guide utility performance through the use of performance incentive mechanisms (sometimes referred to as PIMs). Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources. The ultimate objective of performance metrics and incentives is to better align utility regulatory and financial incentives with the public interest.

Given the policy environment in B.C., FEI believes that looking to jurisdictions such as the U.K., California and New York is appropriate, and that B.C. utilities and the BCUC should be leaders

in using targeted initiatives to better align the incentives under utility ratemaking plans with the public interest.

Synapse Energy Economics Inc.'s report on page 2 of Appendix C8 describes one of the potential pitfalls of Performance Incentive Mechanisms as "Unintended consequences" and states the following:

> Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.

96.5 Please describe the safeguards which FEI and FBC have in place to mitigate the risk described in the above preamble.

Response:

FortisBC has continually demonstrated its commitment to maintaining a high level of service quality to its customers and intends to continue to focus on the traditional areas of its business under its proposed MRPs, as it has in the past. Further, FortisBC's proposed MRPs include a balanced and diverse set of penalties, incentives and safeguards that mitigate against any risk that FEI or FBC would shift attention away from performance areas that do not have incentives:

1. A broad range of service quality indicators are included in the MRPs to ensure that an appropriate level of service is maintained by FBC and FEI. Failure to meet the benchmark thresholds could represent a degradation in service quality and may result in a penalty. Both FEI and FBC have established a strong record of maintaining service quality to customers.

2. Traditional incentives are included in the MRPs to promote a continuous focus on cost efficiency. Specifically, FEI and FBC will have an incentive to contain annual index-based O&M to a level at or below that calculated under the gross O&M per customer amount, and contain Regular capital spending 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.

3. Targeted incentives have been added to broaden the Utilities' focus on addressing the emerging challenges and opportunities in FortisBC's operating environment, which align the incentives in the MRPs with the public interest.

4. FortisBC has proposed to continue with the robust Annual Review process designed by the BCUC for FEI's and FBC's Current PBR Plans, which provides an opportunity for ongoing evaluation of FEI's and FBC's performance under the MRPs. If FEI or FBC were shifting focus away from certain areas of its business, there would be an annual opportunity for corrective measures to be taken by the BCUC over the term of the MRPs.

Regardless, and as indicated at the outset of this response, this will not be an issue as FortisBC will maintain its focus on all performance areas under the proposed MRPs.

On page C-158 of the Application, FortisBC states the following:

> 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.

96.6 Please provide the maximum achievable ROE if all targets are successfully achieved for FEI and FBC and the associated rate impact under this scenario. Please explain and provide all supporting calculations.

Response:

For FEI, the maximum achievable ROE resulting from the Targeted Incentives over the proposed MRP term is 9.10 percent (35 BPS over the currently approved ROE) if all targets are successfully achieved. The associated delivery rate impact under the maximum achievable ROE scenario is approximately $0.041 per GJ (or 1.02 percent). For a typical FEI residential customer with consumption of 90 GJ per year, the delivery rate impact is equivalent to approximately $3.71 per year.

For FBC, the estimated upper range achievable ROE resulting from the Targeted Incentives over the proposed MRP term is 9.54 percent (39 BPS over the current approved ROE) if all targets are successfully achieved. Please note that for FBC, the incremental ROE per year from the Power Supply Incentive (PSI) is dependent on the actual level of power supply mitigation each year, which in turn depends on the market environment, system conditions, and FBC's ability to capitalize on mitigation opportunities from a highly volatile market. Accordingly, FBC cannot project a maximum power supply mitigation that could occur over the proposed MRP term. However, in an effort to be responsive, FBC has used the highest actual power supply mitigation achieved over the past 5 years (2014 to 2018) of approximately $23 million to

determine an upper range estimate of ROE as requested. Please also note that FBC will only achieve an incremental ROE for the PSI when the actual power supply mitigation exceeds $7.5 million. The associated rate impact under the upper range achievable ROE scenario is $0.689 per MWh (or 0.62 percent). For a typical FBC residential customer with consumption of 990 kWh per month (11,880 kWh per year), the upper range rate impact is equivalent to approximately $8.18 per year.

Please refer to the tables below for the calculation of the rate impacts and maximum achievable ROE per year for FEI and the estimated upper range achievable ROE per year for FBC.

FortisBC notes that the associated rate impacts shown in the tables below do not include the associated benefits related to achieving the Targeted Incentives. For example, growth in NGT for FEI will create offsetting revenue, which is a net benefit to FEI's customers. Please refer to the response to BCUC IR 1.96.7 for an explanation of the benefits of the proposed Targeted Incentives.

Please also note that, as discussed in Section C8.4 of the Application, FortisBC proposed that the Targeted Incentives (with the exception of the PSI) will be calculated on a final and full-year basis. Therefore, the impact will be included in the annual review two years subsequent (e.g. 2020 performance will be known in 2021 and will be evaluated in the Annual Review for 2022 rates). For PSI, as discussed in Section 3.3 of Appendix C7, FBC will include a forecast of the incentive in its annual review applications with the final benefit-sharing amount to be trued up in the subsequent year. However, for simplicity FortisBC has shown the rate impacts in the same year that the Targeted Incentives have been met in the table below.

FEI:

Line	Particular	Reference	2020	2021	2022	2023	2024
1	**Targeted Incentives (BPS)**						
2	Growth in RNG	Table C8-1 of Application	10	10	10	10	10
3	Growth in NGT	Table C8-1 of Application	10	10	10	10	10
4	GHG Emissions Reductions (Customer)	Table C8-1 of Application	5	5	5	5	5
5	GHG Emissions Reductions (Internal)	Table C8-1 of Application	5	5	5	5	5
6	Customer Engagement	Table C8-1 of Application	5	5	5	5	5
7	Total (Maximum Achievable)	Sum of Line 2 to 6	35	35	35	35	35
8							
9	**Return on Equity (ROE)**						
10	Base	BCUC Order G-193-15	8.75%	8.75%	8.75%	8.75%	8.75%
11	Targeted Incentive (Max)	Line 7 / 100	0.35%	0.35%	0.35%	0.35%	0.35%
12	**Total (Maximum ROE)**	**Line 10 + Line 11**	**9.10%**	**9.10%**	**9.10%**	**9.10%**	**9.10%**
13							
14	2019 Approved Rate Base ($000s)	Compliane Filing G-10-19 (January 30, 2019)	4,496,946	4,496,946	4,496,946	4,496,946	4,496,946
15	FEI Equity Ratio		38.50%	38.50%	38.50%	38.50%	38.50%
16							
17	2019 Approved Delivery Margin - Non-Bypass ($000s)	Compliane Filing G-10-19 (January 30, 2019)	814,155	814,155	814,155	814,155	814,155
18	2019 Approved Volume Forecast - Non-Bypass (TJ)	Compliane Filing G-10-19 (January 30, 2019)	201,573	201,573	201,573	201,573	201,573
19	2019 Effective Delivery Rates ($/GJ)	Line 17 / Line 18	4.039	4.039	4.039	4.039	4.039
20							
21	**Incremental Revenue Requirement**						
22	ROE (Targeted Incentive)	Line 14 x Line 15 x Line 11	6,060	6,060	6,060	6,060	6,060
23	Income Tax (27%)	(Line 22 / (1-0.27)) x 0.27	2,241	2,241	2,241	2,241	2,241
24	Total Incremental Revenue Requirement ($000s)	Line 22 + Line 23	8,301	8,301	8,301	8,301	8,301
25							
26	**% Increase from 2019 Approved Delivery Margin**	**Line 24 / Line 17**	**1.02%**	**1.02%**	**1.02%**	**1.02%**	**1.02%**
27	Delivery Rate Impact from 2019 Approved ($/GJ)	Line 19 x Line 26	0.041	0.041	0.041	0.041	0.041

FBC:

Line	Particular	Reference	2020	2021	2022	2023	2024
1	**Targeted Incentives (BPS)**						
2	Customer Engagement	Table C8-1 of Application	5	5	5	5	5
3	Growth in EV Transportation	Table C8-1 of Application	5	5	5	5	5
4	Power Supply Incentive (High Range)	Line 11	29	29	29	29	29
5	Total (Maximum Achievable)	Sum of Line 2 to 4	39	39	39	39	39
6							
7	**Power Supply Incentive**						
8	Estimated Mitigation - High Range ($000s)	Estimated based on 2018 Actual	23,000	23,000	23,000	23,000	23,000
9	Customer Share	$7.5M + 0.9 x (Line 8 - $7.5M)	21,450	21,450	21,450	21,450	21,450
10	FBC Share	Line 8 - Line 9	1,550	1,550	1,550	1,550	1,550
11	Power Supply Incentive - BPS (High Range)	Line 10 / (Line 18 x Line 19) x 10000	29	29	29	29	29
12							
13	**Return on Equity (ROE)**						
14	Base	BCUC Order G-193-15	9.15%	9.15%	9.15%	9.15%	9.15%
15	Targeted Incentive (Max)	Line 5 / 100	0.39%	0.39%	0.39%	0.39%	0.39%
16	**Total (Maximum ROE)**	**Line 14 + Line 15**	**9.54%**	**9.54%**	**9.54%**	**9.54%**	**9.54%**
17							
18	2019 Approved Rate Base ($000s)	Compliane Filing G-246-18 (March 15, 2019)	1,341,946	1,341,946	1,341,946	1,341,946	1,341,946
19	FBC Equity Ratio		40.00%	40.00%	40.00%	40.00%	40.00%
20							
21	2019 Approved Revenue Requirement ($000s)	Compliane Filing G-246-18 (March 15, 2019)	370,534	370,534	370,534	370,534	370,534
22	2019 Approved Volume Forecast (GWh)	Compliane Filing G-246-18 (March 15, 2019)	3,319	3,319	3,319	3,319	3,319
23	2019 Effective Rates ($/MWh)	Line 21 / Line 22	112	112	112	112	112
24							
25	**Incremental Revenue Requirement**						
26	Power Supply Incentive (FBC Share)	Line 10	1,550	1,550	1,550	1,550	1,550
27	ROE (Targeted Incentive, excl. PSI)	Line 18 x Line 19 x (Line 2 + Line 3) / 10000	537	537	537	537	537
28	Income Tax (27%)	(Line 27 / (1-0.27)) x 0.27	199	199	199	199	199
29	Incremental Revenue Requirement ($000s)	Sum of Line 26 to 28	2,285	2,285	2,285	2,285	2,285
30							
31	**% Increase from 2019 Approved Revenue Requirement**	**Line 29 / Line 21**	**0.62%**	**0.62%**	**0.62%**	**0.62%**	**0.62%**
32	Rate Impact from 2019 Approved ($/MWh)	Line 23 x Line 31	0.689	0.689	0.689	0.689	0.689

96.7 With reference to each specific target, please explain the basis for FortisBC's determination of the appropriate incentive amount (i.e. 10 BPS, 5 BPS). As part of this response, please explain why the Customer Engagement targeted incentive amount is the same for FEI and FBC, particularly in light of how O&M costs are allocated between FEI and FBC.

Response:

To determine the appropriate incentive for each Targeted Incentive, FortisBC considered a combination of three factors including:

- The benefits flowing to end users, ratepayers, and society;
- The difficulty in achieving the target; and

- A minimum threshold required to make pursuit of the incentive material.

The benefits flowing to end users, ratepayers and society from the achievement of the Targeted Incentives and their difficulty are detailed in the following tables:

FEI		
Opportunity	**Benefits (End User, Ratepayer, and Societal)**	**Difficulty in Achieving Targets**
Growth in Renewable Gas	✔ Reduced emissions ✔ Avoidance of higher cost decarbonization alternatives (electrification)	Target represents an approximate 20-fold increase in contracted renewable gas volumes (~0.3 PJ in 2018 to 6.0 PJ in 2024)
Growth in Natural Gas Transportation	✔ Reduced emissions ✔ Positive impact on rates (via delivery margin) ✔ Reduced operating costs	Target represents a 3.5-fold increase in NGT consumption (~2.0 PJ in 2018 to 7.0 PJ in 2024).
GHG Emissions Reduction (Customer)	✔ Reduced emissions ✔ Positive impact on rates (via delivery margin) ✔ Reduced operating costs	Targets represent a 1.03 fold increase in conversions within a period of expected declines in housing construction (average of 2,612 conversions per year for 2014-2018 to 2,700 for 2020-2024).
GHG Emissions Reduction (Internal)	✔ Reduced emissions	Targets represent a decrease in internal emissions of approximately 8% (2017-2019[135] average to be reduced by 50 tCO_2e/PJ by 2024).
Enhance Customer Engagement	✔ Increased customer engagement and convenience	Target represents a 1.93-fold increase in customer adoption of digital communication channels (29% for 2016-2018 to 56% in 2024).

FBC		
Opportunity	**Benefits (End User, Ratepayer, and Societal)**	**Difficulty in Achieving Targets**
Enhance Customer Engagement	✔ Increased customer engagement and convenience	Target represents a 1.41-fold increase in customer adoption of digital communication channels (22% for 2016-2018 to 31% in 2024).
Growth in Electric Vehicle	✔ Reduced emissions ✔ Support Zero Emissions Vehicle	Targets are to be developed pending the outcome of the EV Charging Inquiry.

[135] For the purposes of this calculation, a starting point of 645 tCO_2e/PJ was used as the 2017-2019 average is not yet known.

Transportation		Mandate	
Power Supply Incentive	✔	Further optimization of power supply costs	Sharing only begins above a $7.5 million benefit threshold.

For those benefits that can be quantified, FortisBC performed a cost-benefit analysis to ensure that the benefits exceed the costs for each incentive and to scale the incentive reward as noted in the considerations above. Please note that enhancing customer engagement was not quantified, as the associated benefits are qualitative. Please also refer to the response to BCOAPO IR 1.92.7.1. In addition, Growth in Electric Vehicle Transportation was not quantified because the targets have not yet been developed.

Targeted Incentives	Analysis Period (yrs)	NPV of Benefits ($000s)	NPV of Cost of Service Impact ($000s)	Gross Benefits/(Costs) ($000s)	NPV of Proposed Incentive - Equivalent BPS ($000s)	Net Impact to Customers Benefit/(Costs) ($000s)
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = (d) + (e)
Growth in Renewable Gas (RNG)	10	666,708	(536,315)	130,393	(10,088)	120,305
Growth in NGT	10	459,458	(40,171)	419,287	(10,088)	409,199
GHG Emissions Reduction (Customer)	15	282,714	(29,891)	252,823	(5,044)	247,780
GHG Emissions Reduction (Internal)	20	9,608	-	9,608	(5,044)	4,564

The cost-benefit analysis for the PSI mechanism is different from other Targeted Incentives. The formula for sharing eligible mitigation benefits shares eligible mitigation benefits over $7.5 million at a rate of 90 percent to customers and 10 percent to FBC. [136] Accordingly, the majority of any benefits generated flow to the customer as illustrated in the table below. Specifically, the table shows a "high range" scenario with $23 million in eligible mitigation benefits per year versus a "low range" scenario with $7.5 million in eligible mitigation benefits per year. In the "low range" scenario, all benefits flow to the customer.

Targeted Incentives	Analysis Period (yrs)	NPV of Benefits ($000s)	NPV of Cost of Service Impact ($000s)	Gross Benefits/(Costs) ($000s)	NPV of Proposed Incentive - Equivalent BPS ($000s)	Net Impact to Customers Benefit/(Costs) ($000s)
Power Supply Incentive	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = (d) + (e)
High Range	5	90,630	-	90,630	(6,549)	84,081
Low Range	5	31,689	-	31,689	-	31,689

FortisBC assigned 10 BPS to the renewable gas and NGT Targeted Incentives based on their level of benefit to end users, ratepayers and society and their associated level of difficulty.

With regard to the minimum threshold for both FEI and FBC, FortisBC considered 5 BPS as the minimum threshold required to make pursuit of the incentives material. Using the 2019

[136] MRP Application, Section C8.3.7, Pages C166-167.

approved rate base and equity thickness for each utility, the equivalent reward for 5 BPS is approximately:

- FEI: $4,497 million x 38.5% x 5 BPS = $0.865 million
- FBC: $1,342 million x 40.0% x 5 BPS = $0.268 million

As demonstrated above, the incentive reward for customer engagement of 5 BPS is the same for FEI and FBC; however, the reward in dollar terms is scaled relative to the size of each utility's equity portion of rate base. The ROE adder methodology used for Targeted Incentives is transparent, simple, and provides a reward that is relative to the size of the utility.

Please refer to Attachment 96.7.

During the Workshop, FortisBC provided an example of how the targeted incentives would be calculated, using the NGT basis point incentive as an example (Exhibit B-3, Slide 31). It appears that the calculation of the reward for the achievement of the annual targets and the MRP Target is the same regardless of "how much" the targets are exceeded by (i.e. it is based on a trigger).

96.8 Please provide FortisBC's rationale for the proposed targeted incentive award calculation and why it should only be based on a trigger point.

Response:

With the exception of the PSI, which has its own distinct calculation, FortisBC's rationale for designing the Targeted Incentive structure based on a binary outcome or "trigger point" was as follows:

- The proposed "trigger point" incentive structure is transparent and simple. FortisBC considered an incentive structure in which the reward gradually increases with positive value added, but considered that this approach was more complex and therefore less transparent.
- The proposed "trigger point" incentive structure incents FortisBC to strive to reach a stretch target that is above and beyond what would otherwise be expected, and that will provide material benefits to customers. This structure should mitigate any perception that FEI or FBC were being rewarded for undertaking ordinary course business.
- Under the proposed "trigger point" incentive structure, end users, ratepayers and society receive the benefits of FEI's and FBC's efforts even if the target is not achieved.

- The proposed "trigger point" incentive structure can include a reward that is material enough to align interests of the Companies with the interests of customers and society.

FortisBC is not opposed to considering alternate structures. For example, FortisBC recognizes that a potential downside of the proposed approach is that FortisBC may lose focus on a particular objective if it becomes clear that the target is not achievable. For this reason, a more graduated incentive structure (akin to the PSI) could potentially be more effective in some situations.

On page C-158 of the Application, FortisBC states the following:

> 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.

96.9 Please confirm, or explain otherwise, that pursuit of these targets requires additional investment in capital and O&M.

Response:

Confirmed. However, O&M and capital requirements vary by incentive and project. As an example, an RNG supply project may, or may not, require an investment in capital. Where pursuit of targets will be funded out of indexed-O&M or FEI's Growth capital, the Companies will have an incentive to manage their overall costs to within inflation. Where the pursuit of targets are funded out of costs that are forecast, the BCUC will have an opportunity to review any proposed spending.

96.9.1 If confirmed, please estimate FEI and FBC's planned O&M and capital spending related to each target during the MRP term. Please identify how the O&M and capital spending will be treated within the MRP (i.e. formula O&M, regular capital, flow-through O&M or capital, etc.).

Response:

The following table identifies the treatment of O&M and capital costs within the MRPs. Please note that:

- For items noted as "forecast annually", FEI and FBC will include a forecast of those items in the Annual Review for 2020 Rates, and in subsequent Annual Reviews.
- For items noted as "index-based O&M", FEI and FBC has not prepared a forecast of these items, as they will be managed within the index-based O&M.
- For items noted as "Regular capital forecast", FEI and FBC have not specifically identified spending related to these items as part of the capital forecast. This is because increased customer engagement and reduced emissions are often secondary drivers or benefits of a capital project whereas the capital forecast has been prepared at the project / program level of definition.
- There may be incremental costs to comply with legislatively mandated federal, provincial and municipal climate policy that are proposed to be forecast annually (and are not included in index-based O&M or in the current capital forecast) that have the effect of reducing internal emissions.

FEI		
Opportunity	**O&M**	**Capital**
Renewable Gas	Forecasted annually (flow-through O&M)	Forecasted annually (flow-through capital)
NGT	Forecasted annually (flow-through O&M)	Forecasted annually (flow-through capital)
Emissions – Internal	Index-based O&M	Regular capital forecast
Emissions – Customer	Index-based O&M	Index-based growth capital
Customer Engagement	Index-based O&M	Regular capital forecast
FBC		
Opportunity	**O&M**	**Capital**
Customer Engagement	Index-based O&M	Regular capital forecast
EV Charging	Forecasted annually (flow-through O&M)	Forecasted annually (flow-through capital)
Power Supply Incentive	Index-based O&M	Additional capital is not anticipated

96.10 Please explain how providing incentives for additional capital and O&M spending is consistent with the principles of an incentive-based rate plan.

Response:

As discussed in the response to BCUC IR 1.96.1, targeted incentives are a form of performance or incentive ratemaking designed to provide incentives to utilities to achieve certain objectives which have been proposed as part of the overall MRP. The achievement of these objectives will require effort on behalf of the utilities along with necessary investments in O&M and capital. As an example, the expansion of RNG supply requires FEI to invest time and effort identifying and developing new RNG projects, which will eventually require O&M and, in some cases, capital funding as they are constructed and put into service. As noted in the response to BCUC IR 1.96.7, the benefits of achieving these targets outweigh their costs.

Further, as explained in Dr. Makhom's report in Appendix C4-1 of the Application, the concept of incentive rate plans is not limited to a cost cutting perspective:

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

96.11 Please explain how the proposed Clean Growth Innovation Fund is connected to each of FEI and FBC's targeted incentives. Please address each incentive, if applicable, in this response.

Response:

The purpose of the Clean Growth Innovation Fund is 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 FortisBC's customers. While technology breakthroughs, cost reductions and energy solutions derived through the Clean Growth Innovation Fund may ultimately benefit areas addressed by Targeted Incentives, the Innovation Fund is separate and

distinct from the Targeted Incentives and any O&M and capital funding used to pursue the targets.

For example, the Clean Growth Innovation Fund may be used to fund the development of new renewable gas technologies such as "wood-to-gas"[137]. If successful, such a technology breakthrough could greatly expand the potential for renewable gas development while also potentially reducing costs. Accordingly, FEI may bring forward more renewable gas projects which contribute towards achievement of the Targeted Incentive. However, the O&M and capital requirements associated with such a project are not funded by the Clean Growth Innovation Fund.

There are also a number of innovation gaps that the Clean Growth Innovation Fund seeks to address that are unrelated to Targeted Incentives. For example, the development of improved non-destructive testing equipment for FEI's gas lines could benefit customers by lowering costs of equipment and testing methodologies in the future.

[137] "Wood-to-gas is the term used to describe renewable gas derived from wood-based feedstock.

97.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.1, pp. C-159 – C-160

Growth in Renewable Gas (RG)

On page C-160 of the Application, FortisBC states the following:

> 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…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.

97.1 What percentage of renewable content in FEI's total natural gas throughput do the targets presented in Table C8-2 of the Application represent? Please provide the percentage of RG content for each year of Table C8-2.

Response:

Total throughput on FEI's system for 2018 on a weather normalized basis to all non-bypass customers was 193.22 PJs. Using this total as the denominator, the percentage of renewable gas content represented by each target is as follows:

	2020	2021	2022	2023	2024
RG Target (PJs)	1.0	1.5	2.0	4.0	6.0
RG Target (%)	0.52	0.78	1.04	2.07	3.11

97.2 Please explain how the targets presented in Table C8-2 were developed, given the 2018 production of 342,300 GJs.

Response:

The targets for renewable gas content were developed in consideration of the following factors:

1. The current level of contracted renewable natural gas supply for 2018,
2. The potential volume of renewable natural gas projects currently under development,
3. The volume of renewable natural gas identified in FEI's 2018 request for expressions of interest (RFEOI) for renewable natural gas supply, and

4. The CleanBC Plan renewable gas content target of 15% by 2030.

In particular, the combination of the RFEOI and the 15% target were the factors that significantly influenced the proposed stretch target for renewable gas supply that equates to an approximate 20-fold increase by 2024.

97.3 For each of the volumes listed in Table C8-2, please list, by year, how much of these targeted supply amounts are either already contracted for, or have development plans already in place. As part of this response, please explain if any of the RG will be supplied by FEI's RG Pilot plant.

Response:

The reference to "FEI's RG Pilot plant" in the Information Request is unclear to FEI.

The table below provides a projection of Renewable Gas (RG) volume over the MRP period for projects which are in service or are expected, but not yet approved.

(PJ's)	2020	2021	2022	2023	2024
Expected Supply	0.47	0.67	0.67	0.67	0.67
RG Target	1.00	1.50	2.00	4.00	6.00

FEI has identified additional RG projects, which if successful, have the potential to increase volumes by 0.5 to 1.0 PJs annually over the MRP period. FEI is also pursuing out-of-province and off-system options which may also increase annual volumes, but remain uncertain.

In addition, FEI is investigating the feasibility and potential of wood-waste derived renewable natural gas and hydrogen. Given the very early stage of these two technology pathways, it remains uncertain if, or how much, RG supply will materialize from these sources.

If approved, the Clean Growth Innovation Fund will allow the development of piloting and demonstration projects in various areas, including hydrogen injection, production of wood-based biomethane, and other renewable gas technologies which seek to lower emissions.

97.4 What is the current demand (in GJs) for RG? Please provide the forecast targets for RG demand for each of the years from 2020-2024.

Response:

The current demand, as measured by the 2019 projected RNG sales, is approximately 460,000 GJ. A forecast of RNG demand for the years 2020-2024 is provided in the table below:

Year	2020	2021	2022	2023	2024
Expected Demand (TJ)	605	660	741	1,064	563[138]

The demand forecast takes into account growth in demand from customers in Rate Schedules (RS) 1B, RS 2B and RS 3B, the scheduled consumption of existing RS 11B customers (including both additions to load as well as contracts that end during the period), as well as potential new long term contracts where FEI has had serious discussions with customers.

FEI is aware of additional customer interest that would represent significant new load in addition to what is shown in the table above. In particular, there is significant interest from large public institutions who are seeking to meet established emissions objectives. Examples include government and post-secondary educational institutions who have expressed interest for up to 2 PJs. It is important to continue to grow RNG supply so that larger institutions can gain confidence in the program and commit to RNG as a long-term means to meet their emissions objectives.

97.5 In a table format, please provide the number of customers opting in for FEI's RNG rate, the average percent of RG content, and the GJ's of delivery for each of the years 2014 through 2019.

Response:

The table below provides the number of customers opting in for FEI's RNG rate, the average percent of RG content, and the GJs of delivery for each of the years 2014 through 2019. FEI notes:

[138] Note that the current demand forecast drops significantly in 2024. This is due to the end of the first term of the TransLink long term sales agreement, as was reflected in previous forecasts. TransLink has not at present confirmed an intention to continue with the service after the initial 5-year term.

- For the "number of customers opting in for FEI's RNG rate", FEI has provided the total number of customers subscribed to all of the applicable Biomethane Service Rate Schedules as at the end of each of the calendar years in question. This number corresponds best with the total GJs of RNG delivered for each of the years.
- For the average percent of RG content, FEI has provided a participant, rather than a volume, weighted average as this provides a clearer picture of overall customer preferences. An average obtained by weighting based on the volume of GJs delivered at various percentages of delivery could allow the choice of a small number of relative large volume consumers to skew the overall results.

	2014	2015	2016	2017	2018	2019[139]
Number of RNG Customers	6,823	6,770	7,482	8,986	10,338	11,670
Average RNG Content Elected	11.0%	12.0%	13.8%	14.9%	15.6%	16.0%
RNG Delivered (GJ)	123,064	150,321	163,589	233,095	276,187	460,000

[139] Forecast.

98.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.2, pp. C-160 – C-161

Growth in Natural Gas for Transportation (NGT)

On page C-161 of the Application, FortisBC provides Table C8-3, which defines the annual consumption targets for NGT.

98.1 In consideration of the 2018 load of approximately 2.0 PJs, please explain how the targets presented in Table C8-3 were developed.

Response:

The targets for NGT were developed in consideration of the following factors:

- The current NGT volume of 2.0 PJs in 2018,
- The contracts currently under development for NGT,
- The prevailing market for NGT in comparison to alternative fuels, and
- The completion of the Tilbury Expansion Facility, which serves transportation end uses amongst other uses.

98.2 For each of the amounts listed in Table C8-3, please provide, by year, how much of these targeted volumes are already contracted for, how much will be from load growth from existing customers, and how much will be from new customers.

Response:

Please see the table below.

	2020	2021	2022	2023	2024
NGT Demand Contracted as of May 31, 2019 (PJ per year)	1.7	1.7	1.6	1.6	1.6
Uncontracted Projected Demand from Existing Customers (incremental to Demand Contracted)	0.07	0.2	0.5	1.1	1.7
Uncontracted Projected Demand from New Customers	0.0	0.0	0.0	0.0	0.0
Total	**1.77**	**1.9**	**2.1**	**2.7**	**3.3**

	2020	2021	2022	2023	2024
NGT Target (PJ per year)	3.0	4.0	5.0	6.0	7.0

FEI has not included any value for contracted demand from new customers because this value is unknown.

99.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.3, pp. C-161 – C-162

GHG Emissions Reductions - Customer

On page C-161 of the Application, FortisBC states: "High levels of housing construction in recent years have contributed to higher customer attachments, and higher conversions."

On page C-162 of the Application, FortisBC states: "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."

99.1 Please provide evidence to support the assertion that the record levels of gross customer additions and conversion activities are "expected to ease in 2019 and through the Proposed MRP period".

Response:

Please refer to the responses to BCUC IRs 1.2.3 and 1.13.11.1 and 1.41.3.

99.2 Please explain how the "Connect to Gas" incremental funding applied for in Section C2.4.2.3 of this Application, and the "GHG Emissions Reductions – Customer" incentive applied for in Section C8.3.3, does not result in FortisBC being rewarded twice for the same initiative.

Response:

While the requested incremental funding for the "Connect to Gas" program may assist in the achievement of the "GHG Emissions Reductions – Customer" incentive to the extent that it supports increased conversion customers, the O&M funding itself does not represent a reward. Rather, the O&M funding only reflects FEI's costs of the program itself.

Please refer to the response to BCUC IR 1.30.2 for a detailed description of the Connect to Gas initiative. As noted in that response, the Connect to Gas initiative covers a broad range of activities including incremental advertising, appliance incentives, and engagement activities that support the attraction and retention of various types of customers, and not just conversion customers.

As illustrated in the response to BCUC IR 1.96.7, even if FEI considered a portion of the $1.2 million incremental funding for Connect to Gas as a cost of this Targeted Incentive, the benefits would continue to exceed the costs.

100.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.4, pp. C-162 – C-163

GHG Emissions Reductions - Internal

In Table C8-6 on page C-163 of the Application, FEI provides the historical GHG emissions intensity for the years 2013 to 2017. FEI also states: "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 tCOe/PJ per year over the Proposed MRP term starting from the 2017-2019 average."

100.1 Please provide the emissions intensity amount for 2018.

Response:

The 2018 GHG emissions have not been verified or accepted by the BC Ministry of Environment at the time of response to this IR. As a result, the Emissions Intensity for 2018 is not available at this time.

100.2 Please clarify if the reduction of 10 tCOe/PJ is cumulative for the years 2021-2024. For example, is the 20 tCOe/PJ drop in 2021 shown in Table C8-6 of the Application a 20 tCOe/PJ drop from the 2017-2019 average or a drop from the 2020 emissions intensity? Please provide a numerical example to illustrate for each of the years 2021-2024.

Response:

Please refer to the example below where it is assumed that the actual 2017-2019 average referenced in the preamble is 600 tCO_2e/PJ. The cumulative annual reduction in Table C8-7 is subtracted from the 2017-2019 average in each case to form the annual emissions intensity target as well as the MRP Target.

	2020	2021	2022	2023	2024	MRP Target
Emissions Intensity Target (tCO_2e/PJ)	600 – 10 = 590	600 – 20 = 580	600 – 30 = 570	600 – 40 = 560	600 – 50 = 550	600 – 30 = 570 avg.

101.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.5, pp. C-163 – C-164, Exhibit B-1-1, Appendix C8, p. 30

Customer Engagement

On page 30 of Appendix C8, it describes one of the design principles of Performance Incentive Mechanisms as "Metrics should be sufficiently objective and largely free from exogenous influences."

Further on page 30 of Appendix C8 it states: "Otherwise, factors that the utility has no control over can influence the results, obscuring the role that utility management played in the outcome."

On page C-164 of the Application, FortisBC states the following:

> 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.

101.1 Please explain how FortisBC's proposed incentive aligns with the design principle quoted above.

Response:

For clarity, the preamble quoted from page C-164 above identified external factors that FortisBC addressed by using the average annual growth in digital tool adoption for the period of 2014 to 2018 in order to normalize some of the variability caused by external factors. The rest of the paragraph is as follows:

> 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 2018 baseline level.

That is, FortisBC took into consideration the variability caused by external influences in the design of this incentive. In addition, while digital channel adoption may currently be affected by outages and weather-related events, FortisBC believes there is an opportunity to continually improve its digital channels to better meet customers' needs, including their needs during such external impacts in the future. Therefore, to the extent that digital channel adoption increases

during outage and weather-related events, this is indicative of a positive outcome that the Companies and Customers would be encouraged to see.

101.2 Please confirm, or explain otherwise, that a portion of FEI and FBC's incremental 2019 Base O&M funding request is related to customer engagement and digital communication.

Response:

Not confirmed. Please refer to the response to BCUC IR 1.29.2.

101.2.1 If confirmed, please explain why it is appropriate for FEI and FBC to receive incremental O&M as part of the proposed MRP as well as a potential increase in achieved ROE for achievement of targeted incentives.

Response:

Please refer to the response to BCUC IR 1.29.2.

101.2.2 If not confirmed, please explain why FEI and FBC's request for additional in-house resources, including a Digital Advisor and Communications Writer/Researcher and the request for "Web-Based Platforms Support" on pages C-32 and C-35 of the Application, respectively, are not related to this targeted incentive.

Response:

As discussed in the response to BCUC IR 1.29.2, the incremental funding noted in the preamble is unrelated to the customer engagement incentive.

102.0 Reference: INCENTIVES

Exhibit B-1, Section C8.3.7, pp. C-165 – C-167; Exhibit B-1-1, Appendix C7; Exhibit B-2, pp. 10-11; Workshop Transcript, pp. 80, 86; FBC 2019 Annual Review proceeding, Exhibit B-2, p. 36; Order G-26-11, Appendix A; FBC 2016 LTERP and LT DSM Plan Decision and Order G-117-18

Power Supply Incentive (PSI)

On page 3 of Appendix C7, FortisBC states: "The 2014-2019 PBR Plan continued to treat all variances in PPE, including those due to optimization activities, as a flow through, with all variances to the account of customers."

In Table 4-2 on page 36 of the FBC 2019 Annual Review application, FBC provided the following table:

Table 4-2: 2018 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Difference
1	Brilliant	$ 39.632	$ 39.620	$ (0.012)
2	BC Hydro PPA	44.906	38.623	(6.283)
3	Waneta Expansion	37.437	37.797	0.360
4	Market and Contracted Purchases	10.951	14.923	3.972
5	Independent Power Producers	0.080	0.081	0.002
6	Self-Generators	0.066	0.028	(0.038)
7	CPA Balancing Pool	-	(0.826)	(0.826)
8	Special and Accounting Adjustments	-	0.002	0.002
9	Total	$ 133.071	$ 130.247	$ (2.824)
10				
11	Gross Load (GWh)	3,485	3,573	87

102.1 In the same level of detail as was provided in Table 4-2 in the FBC 2019 Annual Review application, please provide the forecast and actual Power Purchase Expense for each year of the Current PBR Plan term (including 2019 Projected amounts).

Response:

Table 1 below shows the forecast Power Purchase Expense for each year in the Current PBR Plan term, and Table 2 shows the actual Power Purchase Expense for each year in the Current PBR Plan term as well as the Projected Power Purchase Expense for 2019.

Table 1

Line No.	Description	Approved 2014	Approved 2015	Approved 2016	Approved 2017	Approved 2018	Approved 2019
1	Brilliant	$ 35.764	$ 37.069	$ 38.785	$ 39.373	$ 39.632	$ 41.865
2	BC Hydro PPA	37.201	45.460	47.545	46.968	44.906	52.174
3	Waneta Expansion	-	25.808	37.358	38.330	37.437	40.221
4	Market and Contracted Purchases	14.543	9.380	10.023	11.341	10.951	10.637
5	Independent Power Producers	0.162	0.164	0.195	0.204	0.080	0.076
6	Self-Generators	-	-	-	-	0.066	0.093
7	CPA Balancing Pool	-	(0.044)	-	-	-	-
8	Sale of Surplus Power	(0.508)					
9	Special and Accounting Adjustments	-	-	-	-	-	-
10	Total	$ 87.163	$ 117.837	$ 133.907	$ 136.216	$ 133.071	$ 145.065
11							
12	Gross Load (GWh)	3,519	3,499	3,540	3,559	3,485	3,602

Table 2

Line No.	Description	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Projected 2019
1	Brilliant	$ 35.742	$ 37.054	$ 38.775	$ 39.358	$ 39.618	$ 41.846
2	BC Hydro PPA	35.273	32.936	33.496	40.507	31.542	48.072
3	Waneta Expansion	-	25.361	36.174	37.454	35.133	38.604
4	Market and Contracted Purchases	16.048	15.300	13.663	16.768	18.137	13.868
5	Independent Power Producers	0.437	0.165	0.197	0.083	0.084	0.073
6	Self-Generators	-	-	-	0.101	0.049	0.087
7	CPA Balancing Pool	(1.090)	0.494	0.988	(1.049)	(0.684)	0.416
8	Sale of Surplus Power	(0.320)	(0.475)	-	-	-	-
9	Special and Accounting Adjustments	0.246	(0.129)	(0.124)	(0.008)	(0.036)	0.019
10	Total	$ 86.337	$ 110.707	$ 123.169	$ 133.214	$ 123.842	$ 142.985
11							
12	Gross Load (GWh)	3,451	3,385	3,387	3,594	3,530	3,615

102.1.1 With reference to the PPE variances in each year of the Current PBR Plan term, as provided in response to the above IR, please explain in detail and quantify the components of the annual variances which were attributable to optimization activities. Please also describe the optimization activities in detail.

Response:

Table 1 below shows the variance in each year of the Current PBR Plan term between the Approved PPE and the Actual PPE as provided in the response to BCUC IR 1.102.1. Also included in the table is the Incremental Mitigation, which is the mitigation achieved over and above that already embedded in the Approved PPE.

Table 1

	2014	2015	2016	2017	2018	2019P
Approved PPE	$ 87.163	$ 117.837	$ 133.907	$ 136.216	$ 133.071	$ 145.065
Actual PPE	$ 86.337	$ 110.707	$ 123.169	$ 133.214	$ 123.842	$ 142.985
Variance (million)	$ (0.826)	$ (7.130)	$ (10.738)	$ (3.002)	$ (9.229)	$ (2.079)
Incremental Mitigation (beyond plan)	$ 2,168	$ 4,286	$ 7,015	$ 9,057	$ 14,236	$ 6,020

Table 2 below quantifies the Eligible Mitigation Benefit in each year of the Current PBR Plan term, and is broken down by mitigation type according to the approach discussed in Section 3.1 of Appendix C7 of the Application.

Table 2

($000)	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
[1] PPA Energy Displacement	$ 2,924	$ 1,484	$ 2,151	$ 7,462	$ 10,762	$ 5,707
[2] PPA Capacity Displacement	$ 4,624	$ 4,792	$ 4,685	$ 6,230	$ 6,298	$ 2,843
[3] Surplus Sales	$ -	$ 2,103	$ 4,556	$ 3,392	$ 6,495	$ 5,428
[4] Offsetting Incremental Costs	-$ 65	-$ 125	-$ 132	-$ 164	-$ 413	-$ 417
[5] Eligible Mitigation Benefit = [1]+[2]+[3]	$ 7,482	$ 8,254	$ 11,258	$ 16,919	$ 23,142	$ 13,561

As illustrated by Tables 1 and 2, there is a difference between the Incremental Mitigation in the first table and the Eligible Mitigation Benefit as defined by the PSI application. Comparing Approved PPE to Actual PPE ignores all mitigation activity that is already embedded in the plan at the time of filing and therefore does not fully represent the value added by FBC's optimization activities. For example, 2018 Approved PPE included 237 GWh of market purchases that were executed before the time of filing, a $2.0 million reduction to account for future market activities, and a forecast of surplus sales of $4.2 million. The Incremental Mitigation shown in the table above does not include these amounts.

One of the benefits of the proposed PSI structure is that it is not dependent on any forecast of PPE, rather it is a calculation done on actual data which incorporates all the value added by FBC. FBC will continue to forecast PPE using the best available data at the time, with the objective of minimizing variances between forecast and actual.

FBC is able to achieve the total Eligible Mitigation Benefit as outlined in the PSI by using multiple strategies. Those strategies are presented in FBC's Annual Electric Contracting Plan[140] (AECP) in Sections 5.1 and 5.2. Section 5.1 discusses FBC's strategy for entering into long-term market purchases in order to reduce its energy nomination under the PPA with BC Hydro. Significant time and analysis are required in order to present and execute the strategy outlined in Section 5.1, as factors such as PPA nomination constraints, FBC's risk profile and current market environment must be considered.

Section 5.2 of the AECP focuses on FBC's post-nomination optimization strategy. First, FBC has 25 percent flexibility under its PPA nomination, and can use it either to manage reductions to load forecast, or to create additional market savings in real-time. Next, FBC also can maximize the value of WAX capacity by way of its day-ahead sales of capacity under the CEPSA agreement. Finally, FBC can also mitigate PPA capacity costs by displacing it with market purchases in real time when it is economical to do so. Making effective economic decisions on a real-time operational basis requires substantial effort, knowledge and diligence in assessing both existing resources, short-term market conditions and operational constraints.

On pages 10 and 11 of the Workshop Materials, FortisBC provides an explanation and an example calculation of the PSI. FortisBC describes the first step of the PSI calculation as follows:

> 1. Calculation of the Eligible Mitigation Benefit: The Eligible Mitigation Benefit will calculate the value added by FBC as a result of its PPE optimization activities using "Eligible Resources", net of "Incremental Costs". The Eligible Mitigation Benefit will be determined by comparing FBC's actual cost of supply to FBC's cost of supply if FBC did not undertake any optimization activities with its Eligible Resources, including executing market purchases and selling surplus capacity, less any Incremental Costs. In other words, the Eligible Mitigation Benefit will be calculated by comparing FBC's actual PPE to the calculated PPE under a passive strategy in which FBC did not engage in any active optimization activity, and solely relied on its firm contracted resources to meet load.[8] FBC is using the calculated passive strategy PPE as a floor from which to calculate Eligible Mitigation Benefit. The calculation of the Eligible Mitigation Benefit will be based on actual load data as determined after the fact, thus removing any reductions that would have occurred only due to reduced load, and limiting the Eligible Mitigation Benefit only to savings achieved as a result of FBC's optimization activities using Eligible Resources.

[140] FBC's AECPs are filed confidentially. A non-confidential Executive Summary is attached to the BCUC letter accepting the AECP.

Footnote 8 on page 10 of the Workshop Materials states the following:

> [8] The Eligible Mitigation Benefit will not be calculated by comparing actual to the forecast PPE for rate setting purposes. When forecasting PPE for rate setting, use of the various resources is based on forecast load and not all market purchases for the year have been executed. The Eligible Mitigation Benefit takes actual load into account, along with all mitigation activities over the course of the year.

The calculation of the PSI is provided on page 11 of the Workshop Materials as follows:

Line	Particulars	2020 ($000)	Reference
1	PPA Energy Displacement	$ 5,950	Hypothetical
2	PPA Capacity Displacement	$ 1,980	Hypothetical
3	Surplus Capacity Sales	$ 3,810	Hypothetical
4	Offsetting Incremental Costs	$ (140)	Hypothetical
5	Eligible Mitigation Revenue	$ 11,600	Sum of Lines 1 through 4
6	Customer Share	$ 11,190	$7,500k + 0.9 x [Line 5 - $7,500k]
7	**Power Supply Incentive (FBC Share)**	**$ 410**	**Line 5 - Line 6**

102.2 Using the Actual 2018 PPE results as an example, please provide a detailed calculation and description for determining the Eligible Mitigation Benefit, including the identification and quantification of all Eligible Resources and all Incremental Costs.

Response:

Table 1 below shows 2018 Actual PPE results compared to 2018 Passive PPE, the variance being equal to the Eligible Mitigation Benefit. As discussed in Appendix C7 in the Application, the "passive strategy" is a calculation of power purchase expense if FBC did not engage in any optimization activity using Eligible Resources, and instead relied only on its long-term firm resources to meet demand. Under the proposed PSI, the calculated PPE under the passive strategy is considered a floor to which Actual PPE can be measured against.

Table 1: 2018 Eligible Mitigation Benefit

Line No.	Description	Actual 2018	Passive 2018	Variance
1	Brilliant	$ 39.618	$ 39.618	-
2	BC Hydro PPA	31.542	$ 63.446	$ 31.904
3	Waneta Expansion	35.133	$ 41.628	$ 6.495
4	Market and Contracted Purchases	18.137	$ 3.293	$ (14.844)
5	Independent Power Producers	0.084	$ 0.084	-
6	Self-Generators	0.049	$ 0.049	-
7	CPA Balancing Pool	(0.684)	$ (0.684)	-
8	Special and Accounting Adjustments	(0.036)	$ (0.036)	-
9	Incremental Wheeling	0.413	-	(0.413)
10	Total PPE plus Incremental Wheeling	$ 124.255	$ 147.397	$ 23.142
11				

Table 2 below further breaks down the 2018 Eligible Mitigation Benefit by optimization activity. The Eligible Mitigation Benefit is calculated based on monthly data, but is summarized below on an annual level.

Table 2: Breakdown of 2018 Eligible Mitigation Benefit by Optimization Activity

Line	($000)		2018 Actual	Reference
1	PPA Energy Displacement	$	10,762	
2	PPA Capacity Displacement	$	6,298	
3	Surplus Sales	$	6,495	
4	Offsetting Incremental Costs	-$	413	
5	Eligible Mitigation Benefit	$	23,142	Sum of Lines 1 through 4
6	Customer Share	$	21,578	$7,500k +0.9 x [Line 5- $7,500k]
7	Power Supply Incentive (FBC Share)	$	1,564	Line 5 - Line 6

The calculation of total Eligible Mitigation Benefit is equal to the value added by FBC as a result of its PPE optimization activities using Eligible Resources net of Incremental Costs. Eligible Resources include all market contract and surplus sales that are less than five years in term. FBC can create Eligible Mitigation Benefit by using market contracts to reduce both energy and capacity purchases under the PPA with BC Hydro and selling its surplus capacity under the CEPSA with Powerex, but may incur additional costs, such as wheeling, which are included as an offset.

In 2018, FBC was able to displace 515 GWh of PPA energy purchases with a combination of forward and spot market purchases. Forward market purchases can be done up to two years in

advance, while spot market purchases are executed on a day-ahead or hourly basis. Displacing PPA energy purchases resulted in a cost savings of $10.762 million as shown in line 1 of Table 2.

FBC was also able to displace 355 MW/months of PPA Capacity in 2018 as a result of forward and spot market purchases. This resulted in a cost savings of $6.298 million as shown in line 2 of Table 2. PPA capacity savings can be achieved in three ways: by reducing PPA capacity required for energy, reducing PPA capacity required for peak demand, and saving on the PPA capacity ratchet. These three methods are detailed further in Section 2.2 of Appendix C7 of the Application.

Further, FBC's optimization included day ahead surplus capacity sales, which reduced PPE by $6.495 million as shown in line 3 of Table 2.

In order to facilitate the PPA Energy and PPA Capacity displacements, FBC purchased $0.413 million of incremental wheeling using BC Hydro and Teck Metals Ltd. Transmission, as shown in line 4 of Table 2. Therefore, as shown in line 5 of Table 2, the Eligible Mitigation Benefit is equal to $23.142 million for 2018. This Eligible Mitigation Benefit is then apportioned between the customer and FBC, with the first $7.5 million going to the customer, and any benefit beyond that shared 90 percent to the customer and 10 percent to FBC. The customer's share for 2018 would be $21.578 million, and FBC's share would be $1.564 million, as shown in lines 6 and 7 of Table 2, respectively. The FBC share of the incentive is equal to 6.8 percent of the Eligible Mitigation Benefit. The customer share of the Eligible Mitigation Benefit of $21.578 million is equivalent to an approximate 6 percent rate decrease.

102.2.1 As part of the above response, please provide the detailed calculation of the 2018 PPE under the "passive strategy" and explain all inputs and assumptions.

Response:

Please refer to the response to BCUC IR 1.102.2.

102.3 Please calculate the Eligible Mitigation Benefit, FBC's share of the PSI, and the ROE impact of the PSI based on FBC's proposed PSI calculation for each year of the Current PBR Plan term.

Response:

The following table shows the Eligible Mitigation Benefit, FBC's share of the PSI, and the ROE impact of the PSI based on FBC's proposed PSI calculation for each year of the Current PBR Plan term, as well as the approximate annual rate mitigation for FBC customers as a result of FBC's optimization activities.

Description	Reference	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
Total Eligible Mitigation Benefit ($000)	BCUC IR 1.102.1.1	**$ 7,482**	**$ 8,254**	**$ 11,258**	**$ 16,919**	**$ 23,142**	**$ 13,561**
Customer Share ($000)	Section 3.2 of the Application	$ 7,482	$ 8,179	$ 10,883	$ 15,977	$ 21,578	$ 12,955
Customer Share (%)	Line 2/Line 1	100.0%	99.1%	96.7%	94.4%	93.2%	95.5%
FBC Share ($000)	Line 1 - Line 2	$ -	$ 75	$ 376	$ 942	$ 1,564	$ 606
FBC Share (%)	Line 4/Line 1	0.0%	0.9%	3.3%	5.6%	6.8%	4.5%
Approved Rate Base ($ millions)	2014-2018 Annual Reports to BCUC 2019 - Annual Review for 2019 Rates Compliance Filing	1205	1251	1282	1291	1322	1342
FBC Equity Ratio		40%	40%	40%	40%	40%	40%
ROE Impact (BPS)	[Line 4/(Line 6 x Line 7) x 10]	0.0	1.5	7.3	18.2	29.6	11.3
Revenue at Prior Year Rates ($000)	2014-2018 Annual Reports to BCUC 2019 - Annual Review for 2019 Rates Compliance Filing	$ 293,720	$ 334,531	$ 340,511	$ 352,389	$ 356,340	$ 370,534
Customer Rate Mitigation (%)	Line 2/Line 9	-2.5%	-2.4%	-3.2%	-4.5%	-6.1%	-3.5%

For simplicity, the customer rate mitigation in the table above is calculated in the year the incentive is earned. However, the PPE variance is captured in a deferral account and the actual rate impact occurs when the variance is amortized into rates in the subsequent years.

102.4 Using the Actual 2018 PPE results as an example, please provide further details and supporting calculations for how the "PPA Energy Displacement", "PPA Capacity Displacement" and "Surplus Capacity Sales" are determined.

Response:

Please refer to the response to BCUC IR 1.102.2.

102.4.1 As part of the above response, please explain how these categories correspond/relate to the PPE line items in Table 4-2 of the FBC 2019 Annual Review application.

Response:

Lines 1 and 2, PPA Energy Displacement and PPA Capacity Displacement, would be reflected in Line 2 of Table 4-2 (BC Hydro PPA). Line 3, Surplus Capacity Sales, would be reflected in Line 3 of Table 4-2 (Waneta Expansion). Line 4, Offsetting Incremental Costs, is not included in Power Purchase Expense. As explained in FBC's response Exhibit A-3, the only incremental costs expected at this time are wheeling costs, which are not a component of Power Purchase Expense.

On page 10 of Exhibit B-2, FortisBC states the following:

> To create the PPE mitigation, FBC may incur additional costs…At this time, the only known Incremental Costs will be short-term wheeling reservations from BC Hydro and wheeling costs on 71 Line, which will be included as an offset to the Eligible Mitigation Benefit.

On page 8 of Appendix C7 in Exhibit B-1, FortisBC states the following:

> All market contracts and surplus sales that are less than five years in term will be considered Eligible Resources and included in the calculation of Eligible Mitigation Benefit. Eligible Resources include wholesale market arrangements and surplus sales, including any revenue under the CEPSA with Powerex, or successor agreement.

102.5 Please clarify whether, in the CEPSA with Powerex, there may be any additional costs to be incurred by Powerex, as a result of additional wholesale market arrangements and surplus sales. If so, would these costs be passed onto FBC and its ratepayers?

Response:

No additional costs to Powerex under the Capacity and Energy Purchase and Sale Agreement (CEPSA) will be passed onto FBC or it customers due to the Power Supply Incentive (PSI) or any additional wholesale market arrangements or surplus sales that occur due to the PSI.

On page 6 of Appendix C7, FortisBC discusses different methods it can mitigate through its PPE: PPA Energy Displacements, PPA Capacity Displacements, and Surplus Sales.

102.6 Please compare the current price of energy under FBC's PPA with BC Hydro against the annual average mid-C price of energy in each of the last five years.

Response:

The following table shows a comparison of the energy price under FBC's Power Purchase Agreement (PPA) with BC Hydro (effective April 1 in each year) against the annual average Mid-C energy price. The average Mid-C energy price is calculated based on the average hourly price for each year as published by the Powerdex Index, which is then converted to Canadian dollars using the average annual rate from the Bank of Canada. This does not take into account transmission costs or any other transaction costs required to deliver energy to the FBC service area.

While the Mid-C Average hourly price has been lower than the PPA energy rates over the past five years, that comparison does not illustrate the volatility present in the Mid-C market. The Mid-C High and Mid-C Low prices have been included in the Table below in order to further illustrate hourly fluctuations which occur in the market. Furthermore, FBC manages market purchases to ensure power is purchased when it is useful, and the Mid-C annual average price does not represent the average price of power that FBC could have purchased, as it includes many hours in which power purchases for FBC would not have been optimal or practical.

$CAD/MWh					
Year	Mid-C High	Mid-C Low	Mid-C Avg	PPA	Variance: Avg Mid-C vs. PPA
2014	$ 171.33	$ (0.39)	$ 31.74	$ 42.62	$ (10.88)
2015	$ 94.74	$ 3.85	$ 28.45	$ 45.18	$ (16.73)
2016	$ 58.72	$ 0.64	$ 25.75	$ 46.99	$ (21.24)
2017	$ 108.71	$ (6.58)	$ 27.23	$ 48.63	$ (21.40)
2018	$ 171.56	$ (0.99)	$ 35.99	$ 50.09	$ (14.10)

102.7 Please compare the current price of capacity under FBC's PPA with BC Hydro against the annual average price of capacity in each of the last 5 years.

Response:

The Power Purchase Agreement (PPA) Capacity Displacement describes market purchases for a limited time period, as short as a single hour, such that a PPA capacity purchase is avoided.

Calculating an annual average price of market capacity may be appropriate in a long term resource analysis where the cost of market capacity can be compared to proposed physical resources such as a pumped storage hydro facility. It provides little, if any, guidance as to whether FBC will be able to economically achieve PPA Capacity Displacements or surplus sales.

However, as requested, the table below shows a comparison of the capacity price under FBC's PPA with BC Hydro (effective April 1 in each year) against the annual average Mid-C Day-Ahead spread (Day-Ahead Peak price less the Day Ahead Off-Peak price as published by the Intercontinental Exchange) for the past five years.

Due to the lack of a pure capacity market at Mid-C, the annual average Mid-C Day-Ahead spread was used as a proxy for the capacity price. A capacity product could be replicated by purchasing energy during the on-peak hours, and selling energy during the off-peak hours, incurring the cost of the spread between the two prices. The annual average Mid-C Day-Ahead spread was converted to Canadian dollars using the average annual rate from the Bank of Canada. This does not take into account transmission costs or any other transaction costs required to deliver energy to and from the FBC service area, nor does it fully illustrate the volatility that is present in the Mid-C market.

$CAD/MW/year			
Year	Mid-C Avg Spread	PPA Capacity	Variance: Avg Mid-C Spread vs. PPA Capacity
2014	$ 102,905	$ 87,250	$ 15,655
2015	$ 60,036	$ 92,497	$ (32,461)
2016	$ 61,853	$ 96,196	$ (34,344)
2017	$ 98,334	$ 99,563	$ (1,229)
2018	$ 129,811	$ 102,550	$ 27,261

102.8 Please outline FBC's load resource balance and planning process to identify enough energy and capacity available to service its domestic load. Include considerations on how FBC determines its reserve margins, surplus sales, and surplus capacity.

Response:

FBC has a number of different planning processes that it uses to identify how it will be able to serve its domestic load. Regarding long term planning, approximately every five years FBC files a Long Term Electric Resource Plan with the BCUC that spans a 20-year planning horizon. For medium to short-term planning, FBC files an Annual Electric Contracting Plan with the BCUC, which outlines FBC's plan to meet load over the next four years. In both of these filings FBC is ensuring that it has sufficient energy and capacity available to service its domestic load. Please refer to the response to BCUC IR 1.102.1.1 which discusses FBC's long-term and shorter term strategies.

On a day ahead basis, for each hour over the next days, FBC reviews multiple hourly load forecasts, weather forecasts, and industry publications to select a reasonable load forecast. For supply, FBC reviews planned generation availability, transmission outages, its annual minimum take and nomination under the PPA with BC Hydro, market and weather data to forecast market prices, and determines the optimal balance of resources to use to meet load and the amount of surplus capacity to sell. These factors all must be considered while ensuring that FBC remains compliant with all contracts, agreements and industry standards, including reserve margins. The result of this work is a forecast of load matched with a schedule of available resources for each hour of the day.

In real time, 24 hours a day, FBC staff tracks actual loads compared to forecast, and reforecasts load and resources for the remainder of the day and the next day. They also monitor generation and transmission outages, energy schedules, and all other system inputs in the load and resource balance, and make adjustments as needed to ensure sufficient resources to meet domestic load at the lowest reasonable cost, while ensuring compliance with all contracts, agreements and industry standards.

On page 80 of the Workshop Transcript, FortisBC stated: "The 7 and a half million adjustment to this benchmark represents a baseline at the lower bound of our optimization experience over the past few years."

102.9 Please provide the details of the upper bound and mid-level bound of the optimization savings over the Current PBR Plan term. Please provide support for these amounts.

Response:

As illustrated in the response to BCUC IR 1.102.1.1, the optimization savings achieved over the Current PBR Plan term range from approximately $7.5 million to $23.1 million, and the average of the term of the Current PBR Plan is $13.4 million.

102.10 Please provide the rationale for using the lower bound (i.e. $7.5 million) of the optimization savings for the past few years as a starting point to apportion the savings between FBC and ratepayers.

Response:

The PSI, unlike the other Targeted Incentives, does not use a binary stretch target due to differences in the incentive structure. In other words, the other Targeted Incentives use a stretch target, which, if met, results in FBC receiving an incentive based on an ROE adder which does not change other than with fluctuations in the equity portion of rate base.

In contrast, the PSI is dynamic. The PSI threshold of $7.5 million is not a stretch target, and it is not a level at which FBC would receive the full incentive. Rather, this is just the threshold at which the sharing of benefits begins with 90 percent of the benefit beyond this amount flowing to customers and 10 percent to FBC. Thus, the purpose of the threshold is to:

- Provide a base level of savings to the customer before any sharing begins, which ensures there is no reward unless customers first receive a base level of savings; and
- Align the interests of FBC and the customer in reducing power supply costs by providing a continuous cost reduction incentive above the threshold.

The proposed PSI meets these objectives and represents a fair and reasonable incentive for reducing power supply costs on behalf of customers.

On page 2 of Appendix C7, FortisBC states the following:

FBC's proposed PSI will determine the reduction in PPE achieved by FBC's optimization activities, which is referred to as the Eligible Mitigation Benefit, and will create a Benefit Sharing Mechanism to apportion the benefits reasonably between customers and the Company.

102.11 Based on FBC's proposed PSI, please explain how incremental costs would be treated under a scenario where the incremental costs are higher than the Eligible Mitigation Benefit. Would FBC be responsible for all of the downside risk? If no, please explain why it would be appropriate for ratepayers to bear the responsibility of the downside risk.

Response:

Under the proposed PSI, if the incremental cost was greater than the Eligible Mitigation Benefit, then there would be no benefit available for sharing, and FBC would not receive an incentive. However, FBC does not believe that this would ever occur. Any incremental costs related to short-term transmission would only be purchased if it was creating incremental savings, and any incremental costs related to any additional market research are expected to be minimal, if any at all.

Any labour spent on power supply activities, either existing or incremental, would be funded through index-based O&M. Therefore, under the proposed PSI, incremental O&M would not be included as an incremental cost offsetting against Eligible Mitigation Benefits. FBC would share in the downside risk for any incremental labour costs which would flow through the earnings sharing mechanism.

On pages 2 and 3 of Appendix C7, FBC provides the regulatory history of FBC's PPE incentives, including the following:

- In 1999, a power purchase incentive mechanism, called the Market Incentive Mechanism (MIM), was introduced in response to customer concerns. The MIM shared benefits arising from displacing BC Hydro supply with market purchases. FBC's share was all of the first $0.2 million, 50 percent of the next $0.4 million, and 25 percent of amounts over $0.6 million. FBC's share was capped at $0.5 million.
- From 2000 to 2005, the MIM continued with slight changes. FBC' share was 35 percent of the first $1.0 million and 25 percent of amounts over $1.0 million with no cap.

- Under the 2007 to 2011 PBR, the PPE variance was shared 50 percent to customers and 50 percent to the Company through the ROE sharing mechanism applicable during the period.

102.12 Please provide a numerical example to compare and contrast each of the three PPE incentive approaches described in the above preamble to FBC's proposed PSI. Please explain all inputs and the reasons for the differences in results. Please also highlight the difference in the impact to ratepayers and to FBC as a result of each approach.

Response:

For greater clarity, FBC has provided three examples of the proposed PSI calculation compared to the previous three incentive mechanisms. Table 2 below illustrates, using numerical examples, the incentive under a range of market conditions. The table is followed by an explanation of each of the scenarios under each incentive mechanism.

Assumptions

The three scenarios in Table 1 below illustrate a range of market conditions.

Table 1: Three Scenarios Illustrate a Range of Market Conditions

Scenario	PPE Variance	Eligible Mitigation Benefits (EMB)
Scenario 1	$40 million below approved	$40 million
Scenario 2	$30 million below approved	$15 million
Scenario 3	$20 million above approved	$8 million

As illustrated by scenario 3, the EMB can be positive even though actual power purchase expenses (PPE) are above approved (forecast). This scenario reflects that PPE is driven by load; however, FBC can add value by reducing PPE lower than what it would have otherwise been through optimization activities.

For the 1999 and the 2000 to 2005 Market Incentive Mechanism (MIM), FBC has assumed that the calculation of benefits is consistent with the calculation of the EMB in the proposed PSI. As shown in Table 2 below, the FBC incentive varies dramatically under the three methods, for reasons described below.

Scenario Results

Table 2: Scenario Results

($million)	Scenario #1	Scenario #2	Scenario #3
Approved PPE	$ 120	$ 120	$ 120
Actual PPE	$ 80	$ 90	$ 140
Actual EMB	$ 40	$ 15	$ 8
PPE Variance	$ (40)	$ (30)	$ 20
FBC Incentive ($M)			
1999 MIM	$ 0.50	$ 0.50	$ 0.50
1999 MIM (no cap)	$ 10.30	$ 4.05	$ 2.30
2000 to 2005 MIM	$ 10.10	$ 3.85	$ 2.10
2007 to 2011 PBR	$ 20.00	$ 15.00	$ (10.00)
Proposed PSI	$ 3.25	$ 0.75	$ 0.05
FBC Incentive (% of EMB)			
1999 MIM	1%	3%	6%
1999 MIM (no cap)	26%	27%	29%
2000 to 2005 MIM	25%	26%	26%
2007 to 2011 PBR	50%	100%	N/A[141]
Proposed PSI	8%	5%	1%

1999 MIM

Under the 1999 MIM, the FBC incentive would have been capped at $0.5 million. FBC believes that this method has some merit as it is tied to actual optimization activity achieved. However, without the cap in place, the formula would have resulted in an incentive of $10.3 million (26 percent) in Scenario #1, $4.05 million (27 percent) in Scenario #2, and $2.3 million (29 percent) in Scenario #3.

2000 to 2005 MIM

Under the 2000 to 2005 MIM, the cap was removed and the formula changed slightly. FBC's share of incentive under the example calculation would have been roughly 25 percent in all scenarios.

[141] N/A indicates no incentive was available to share. FBC would have been required to pay under this scenario and incentive structure.

2007 to 2011 PBR

Under the 2007 to 2011 PBR, FBC received 50 percent of the variance between Approved PPE and Actual PPE, including any variances to load, or other reasons. As with all incentives, this incentive balanced risk and reward, which was more pronounced than other incentives analysed. Using this method, FBC would have received 50 percent of the EMB in Scenario #1, and 100 percent of the EMB in Scenario 2. However, FBC would have been required to pay $10 million in Scenario #3 despite the fact that its optimization activities created $8 million in savings for the customer. This method is heavily influenced by load and has less of a clear link between the Company's optimization activities and the incentive that it earns.

Proposed PSI

The PSI incentive provides a range of incentive from 1 percent to 8 percent of the EMB under the various example scenarios. In Scenario #1, FBC receives $3.25 million as an incentive, equal to 8 percent of the EMB, however, this is because the results for the customer are exceptional. In this scenario, FBC customers would receive $36.75 million in savings, equal to an approximate 10 percent rate reduction. Under Scenario #2, FBC receives 5 percent of the EMB and 1 percent in Scenario #3. As illustrated, the proposed PSI works well under varying and dynamic market conditions, is unrelated to any PPE forecast variances, and provides a more direct link between optimization activities and the incentive reward. Based on the comparison of the four incentive mechanisms, the PSI provides a reasonable balance of risk and return while providing the majority of the benefits to customers.

On page 3 of Appendix C7, FBC describes the four "objectives and guiding principles" of the PSI.

102.13 With reference to each of the four "objectives and guiding principles", please explain how each of the three previous PPE incentive approaches (i.e. in 1999, 2000-2005, and 2007-2011) compares to the proposed PSI in terms of alignment to these objective and principles.

Response:

The four objectives and guiding principles of the PSI are Alignment of Interests, Supply Security, Fair and Reasonable Incentives, and Simplicity, and are further described in Section 1.2 of Appendix C7. FBC believes that each of the three previous PPE incentive approaches substantially met the objectives of Supply Security and Simplicity, as they discouraged any activity that might adversely affect the security of supply and were administratively simple.

The 1999 MIM aligned the interest of the Company and the Customer, but the cap on the incentive limited that alignment. As discussed in the BCUC guiding principles in Order G-26-11, an upper limit is not required if the incentive is reasonable and the amount earned justified. Moreover, with the imposition of a cap, substantial exertions by the Company could go unrewarded, thus making this incentive mechanism less fair and reasonable.

The 2000 - 2005 MIM also aligned the interest of the Company and the Customer, as the incentive was based directly on Company performance. However, as discussed in BCUC IR 1.102.12, the incentive received by the Company was approximately 25 percent in all scenarios. This creates the possibility of a significant reward that is not tied to substantial exertions, which may be less fair and reasonable for both the Customer and the Company.

The 2007 - 2011 PBR incorporated load variance, which is influenced by external factors and not performance, and was therefore encumbered in its ability to align the interests of the Company and the Customer. Inclusion of load variance also has the potential to dampen the effect of substantial exertions, and vice versa. Accordingly, this incentive mechanism was also encumbered in its ability to be fair and reasonable.

FBC believes that while each of the three previous PPE incentive approaches worked towards meeting these objectives and principles, that the proposed PSI is superior when it comes to Alignment of Interests and Fair and Reasonable Incentives. In comparison, and as illustrated in the response to BCUC 1.102.12, the proposed PSI meets all four of the objectives and provides an optimal mix of benefit for customers and incentive for the Company.

On page 1 of Appendix C7, FortisBC states the following:

> The wholesale electricity marketplace, however, is complex and dynamic. As a result, recognizing and taking advantage of opportunities to mitigate power purchase costs requires vigilance in monitoring developments, and having policies and strategies in place to create value when opportunities arise. FBC must also ensure that these activities do not compromise security or reliability of supply for customers.
>
> 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.

On page 9 of Appendix C7, FortisBC states: “At this time, the only Incremental Costs will be short-term wheeling reservations from BC Hydro and wheeling costs on 71 Line, which will be included as an offset to the Eligible Mitigation Benefit.”

102.14 Please explain if FBC currently has policies and strategies in place to enhance performance in the area of power supply and, if so, please provide details of these existing policies and strategies and how they would change/be impacted if the PSI were approved.

Response:

FBC currently has policies and strategies in place to optimize its power purchase portfolio, which is presented confidentially to the BCUC each year in its Annual Electric Contracting Plan (AECP). The purpose of the AECP is to outline FBC's plan to meet the peak demand and annual energy requirements for the following operating year. The AECP outlines FBC's plan for portfolio optimization to maximize benefits to customers. It includes a review of the market environment, load forecast and available resources. It also provides the justification for FBC's Annual Energy Nomination under the power purchase agreement between FBC and BC Hydro as well as facilitates the required separate acceptance under section 71 of the *Utilities Commission Act* of energy supply contracts that have been contemplated under the AECP.

While the AECP outlines the annual plan, the PSI is expected to further align the interest of the Company and the customer by ensuring FBC is taking advantage of all the opportunities presented in the AECP, and spending sufficient resources to maximize performance in the area of power supply. This includes incentive to find new opportunities and strategies to create value for the customer, which FBC will include in the AECP as they become known and prior to implementation.

102.15 Please confirm, or explain otherwise, that FBC currently has employees to execute the proposed power supply optimization activities.

Response:

FBC currently has employees allocated to power supply operations, which include the power supply optimization activities, and is funded through formula O&M.

102.15.1 Please explain if the compensation and other costs of such employees will be included to offset the Eligible Mitigation Benefit.

Response:

FortisBC has proposed that employee-related expense will be funded through index-based O&M, and will not form part of offsetting incremental costs in the Eligible Mitigation Benefit calculation.

102.15.2 Please explain if the employee compensation benefits include bonus payments and if they are linked to maximizing the Eligible Mitigation Benefit.

Response:

The proposed PSI is not expected to change employee compensation structures. The compensation structure for management and exempt employees includes an incentive component based upon the achievement of both corporate and individual objectives. Individual objectives for those management and exempt employees with influence over power supply operations include objectives such as reducing power purchase costs.

102.15.3 Please explain if FBC plans to employ additional employees to help execute the power supply optimization activities if the proposed PSI is approved. If yes, please explain if the additional employee compensation costs would be included to offset the Eligible Mitigation Benefit.

Response:

At this time, FBC does not plan to increase the employees dedicated to the power supply operations. If during the term of the MRP, FBC believes that it is prudent to allocate more employees for the purposes of capturing optimization activity under the PSI, the employee-related expense will be funded through index-based O&M. As noted in the response to BCUC IR 1.102.15.1, such costs will not form part of the EMB calculation.

On pages 3 and 4 of Appendix C7, FortisBC states: "Furthermore, the PSI will encourage FBC to seek out new mitigation activities in an attempt to increase the optimization benefit, while continuing to ensure security of supply."

102.16 If possible, please provide examples of what these new mitigation activities might be.

Response:

At this time FBC does not have any new optimization activities that it has identified. Should FBC seek to implement any new activities, they will be presented to the BCUC in the Annual Electric Contracting Plan prior to implementation.

On page 1 of Appendix C7, FortisBC states that it "proposes a Power Supply Incentive (PSI) to encourage FBC to increase efficiency, reduce costs, and enhance performance in the area of power supply, over and above what is reasonably expected in the normal stewardship of FBC's business."

102.17 Please discuss whether the objectives stated above should be considered by FortisBC as normal business objectives of a prudent business.

Response:

As stated in the response to BCUC IR 1.96.1, the PSI, as part of FBC's Targeted Incentives, represents a form of performance or incentive ratemaking designed to provide incentives to FBC to achieve certain objectives. As stated in Section 60 of the Utilities Commission Act, the BCUC must have due regard to setting a rate that "encourages public utilities to increase efficiency reduce costs and enhance performance" and "may use any mechanism, formula or other method of setting the rate that it considers advisable".

Achieving objectives above what is "reasonably expected in the normal stewardship of the FBC's business" describes performance that is above the "normal business objectives of a prudent business". FBC does pursue these objectives as part of its normal business; however, in the absence of an incentive, FortisBC is less likely to achieve the same level of performance as it would with an incentive. As stated in the response to BCUC IR 1.96.3, this is due to the lack of an incentive to undertake the extraordinary efforts and investment of resources required to achieve these outcomes and the resulting shift in focus to traditional incentives and service quality.

The PSI design reflects simplicity, the alignment of interests, a fair and reasonable incentive, without compromising the security of supply. The PSI ensures that the customer will continue to receive the majority of the benefits of any optimization activities, and FBC will only share in benefits above what is reasonably expected in the normal course of business. It is just and reasonable for the BCUC to approve a ratemaking plan that includes such incentives as they encourage FBC to enhance its performance and will benefit customers.

102.17.1 If yes, please explain why the objectives stated in the above preamble should be considered as being over and above the normal stewardship of FBC's reasonable management of utility costs.

Response:

Please refer to the response to BCUC IR 1.102.17.

On page 4 of Appendix C7, FortisBC states that in Order G-26-11, the BCUC identified eight Guiding Principles to help develop an incentive plan for FEI and that "FBC believes that these principles are appropriate to consider in the development of the PSI."

In Table C7-1 on page 4 of Appendix C7, FortisBC lists the BCUC's Guiding Principles and discusses how the principles relate to FBC's proposed PSI.

Guiding Principle No. 8 in Table C7-1 of Appendix C7 states the following: "The sharing under the proposed PSI is 10 percent of savings above the first $7.5 million of any reduction in PPE. FBC considers this to be the minimal amount required to provide an incentive to the Company to achieve value over and above what would otherwise be expected."

102.18 Please further explain why FBC considers the 10 percent of savings above the first $7.5 million to be the "minimal amount required to provide an incentive to the Company to achieve value over and above what would otherwise be expected." How was this minimum amount determined and what were the factors this determination was based on? Please explain in detail.

Response:

The PSI calculation was determined by looking at historic results, and selecting a threshold and sharing mechanism that would generally meet the guiding principles detailed by the BCUC in Order G-26-11. The proposed PSI calculation strikes a balance between:

- ensuring the customer receives the benefit associated with what is reasonably expected in the normal course of business;
- providing an incentive that is sufficient to align the interest of the customer and Company; and
- ensuring the incentive is limited to the minimum necessary to obtain the desired benefit.

Accordingly, sharing under the proposed PSI only materializes when the customer is already receiving significate rate mitigation. The baseline of $7.5 million in savings that is allocated to customers results in an approximate effective 2 percent rate decrease prior to the Company receiving any incentive.

In addition, the sharing of benefits above this threshold is distributed 90 percent to the customer and 10 percent to the Company to ensure the customer receives the majority of the benefits, while providing the Company with continued incentive to reduce power purchase costs.

Based on historical results, as detailed in BCUC IR 1.102.3, under the proposed PSI, FBC's incentive through the Current PBR Plan period would have ranged from 0 percent to 6.8 percent of Eligible Mitigation Benefit. In the scenario where FBC would have received a 6.8 percent incentive, equal to approximately $1.6 million, the customer would have received $21.6 million in benefits, effectively equal to an approximate 6.1 percent rate decrease. The proposed PSI meets the proposed objectives including the alignment of interests of the customer and the Company, and provides the Company with a fair and reasonable incentive.

In the Reasons for Decision attached as Appendix A to Order G-26-11 regarding FEI's (then Terasen Gas Inc.) Application for Approval of a Gas Supply Mitigation Incentive Program (GSMIP) for the November 1, 2010 to October 31, 2013 Three-Year Period (2011 GSMIP Decision), the BCUC stated:

> The Commission directs that the GSMIP in effect for 2009/10 will be extended for one year commencing November 2010, and that TGI will establish a working group that includes representatives from TGI, Commission staff, and other

parties to meet in early 2011 to revisit the objectives of GSMIP and to discuss the reformulation of the program to ensure alignment with the objectives.[142]

…

The Commission's intention is that the working group assist TGI in developing a reformulated incentive program so that Terasen Gas can file an application with the Commission by August 2, 2011 for a GSMIP commencing November 1, 2011. The Commission believes that it will be helpful for TGI to engage the services of an outside consultant with expertise in incentive plans, and for the consultant to participate in the working group discussions for the purpose of informing the group members. The Commission also concludes that, based on the submissions of participants and other evidence in the proceeding, that it will be helpful for the Commission to identify Guiding Principles to guide the working group discussions. Therefore, the Commission identifies the following Guiding Principles for a GSMIP commencing November 1, 2011.[143] [*Emphasis added*]

102.19 Please discuss if FortisBC undertook any consultation with stakeholders, including customer groups, in the development of its proposed PSI. If yes, please provide the details of the consultation. If no, please explain why not.

Response:

FBC has not undertaken any consultation with stakeholders specific to the development of the proposed PSI. During the stakeholder consultation sessions conducted for the Application, the PSI was not raised specifically as the focus was primarily on soliciting feedback on some key terms for the Application including engagement, investment and innovation. Please also refer to Section B2.5 of the Application and the response to BCUC IR 1.3.4 for further discussion of consultation for the MRP.

102.20 If FBC was directed to establish a working group to discuss the implications, functionality and design of a PSI, what would FBC's timeline be to complete such a process? Please discuss.

[142] BCUC Order G-26-11, Appendix A, page 3.
[143] BCUC Order G-26-11, Appendix A, page 13.

Response:

FBC believes that the current process provides for an appropriate and sufficient review of the proposed PSI. If FBC were to be directed to establish a working group, FBC believes it should be in the context of a BCUC determination that a PSI is in the public interest.

The length of time required to complete consultation with a potential working group on the design of the PSI could likely be completed in two to three sessions over a two to three month period with a reasonable chance of consensus. If consensus is not reached in that timeframe, additional time may be required if consensus seems possible. If consensus does not seem possible, then FBC would need to request a determination by the BCUC on the design of the PSI.

102.20.1 As part of the above response, please discuss the pros and cons of establishing a working group similar to what was directed in Order G-26-11 regarding FEI's GSMIP.

Response:

Please refer to the response to BCUC IR 1.102.20.

102.21 What is FBC's understanding of customer's acceptance of the proposed PSI? Please discuss.

Response:

In the 24 year period between 1996 and 2019, FBC had incentives in all years but nine, indicating historic support and acceptance of power supply incentives. FBC believes that the proposed PSI is more transparent and robust as compared to previous incentives, and also delivers a fair and reasonable incentive to FBC as discussed in the response to BCUC IR 1.102.12. While FBC has not consulted with interveners on the proposed PSI, FBC interveners have been generally supportive of power supply incentives in the past.

102.22 Please discuss if FBC engaged the services of an outside consultant with expertise in developing incentive plans. If yes, please provide details of the consultation process including reports and/or meeting notes from the outside consultants. If no, please explain why not.

Response:

FBC has not engaged the services of an outside consultant. FBC believes that given the history of power supply incentives with FBC, the uniqueness of FBC's specific PPE portfolio, along with the simplicity and transparency of the proposed PSI, an outside consultant was not required.

102.23 Please provide a detailed comparison of FBC's optimization strategy, activities and resources utilized to FEI's gas mitigation strategy, activities and resources utilized.

Response:

FBC and FEI operate in markets that differ significantly, resulting in challenges that are unique to their situations. Accordingly, their optimization opportunities are not easily compared. However, FBC and FEI's optimization strategies have the following general similarities:

- They are both based on the short-term optimization of existing long-term resources;
- The mitigation efforts require significant effort to achieve results in dynamic markets; and
- Customers receive a significant portion of benefits resulting from the Companies' performance.

Regarding their planning activity, both Companies:

- File annual contracting plans (ACP) with the BCUC, which outlines their optimization strategies, activities and resources for the upcoming year.
- Are required to align their ACPs with their long-term resource plans. The most recent of the ACPs are accepted by the BCUC by way of Order L-28-19 for FBC and Order L-19-18 for FEI.

- Perform optimization and mitigation activity within the parameters set by the long-term resource plan and their ACPs, and that does not increase their respective security of supply risks.

The following table compares FBC and FEI's optimization activities as it relates to transportation, commodity, and storage:

	FEI	FBC
Transportation	FEI can mitigate unutilized transportation capacity by entering into a supply purchase from others at an upstream market and entering into a corresponding sale to others at a downstream market. Transportation Mitigation transactions are those conducted on Enbridge T-North and T-South, Foothills, Southern Crossing Pipeline (SCP) and Intra-Alberta NOVA. The Transportation Mitigation transactions could be a spot market transaction or a forward market transaction. Actual sales volumes are net of pipeline fuel. FEI may also mitigate unutilized transportation capacity by entering into Capacity Release transactions, whereby FEI releases capacity to a third party who then pays FEI for the right to use its transportation capacity. The Capacity Release transactions could be a spot market transaction or a forward market transaction. Capacity Release transactions are conducted on Enbridge T-North and T-South, Foothills and Intra-Alberta NOVA. Capacity Release Mitigation Revenue is calculated for each transaction as the total amount of revenue received for release of the capacity.	FBC secures firm transmission to meet its planned requirements through BC under both the Amended and Restated Wheeling Agreement and the BC Hydro PPA. These resources cannot be mitigated without impacting the long-term planning which could increase the risk of security of supply. As part of FBC's optimization it may use Teck Metal Ltd's 71 Line or purchase short-term transmission from BC Hydro, both of which are included as an offset to the Eligible Mitigation Revenue.
Commodity	FEI will resale commodity purchases only when surplus supply has been purchased in excess of what is needed to serve core load. When FEI has excess purchased supply, FEI has the option to sell it back at the same market hub, or transport it to sell to a downstream market. FEI will look for transactions that yield the highest expected net-back value, given the constraints on what is operationally feasible.	FBC's optimization activities mainly include mitigating the cost of commodity supply, while increasing the value of the surplus sales. For more detail, please refer to BCUC IR 1.102.1.1.
Storage	If FEI has available gas storage capacity and the near price is lower than the forward market price, FEI will enter into a purchase in the nearby month and a sale for a higher price in the forward month.	FBC uses its storage resources available under the CPA as part of its overall mitigation efforts. The impact of the storage cannot be

	FEI	FBC
	This is referred to as a "park" transaction. FEI would contemplate the transaction so long as it didn't negatively impact its ability to fill storage for serving winter customer load, and if the storage carrying costs were less than the value of the price spread between the purchase and the sale transactions. If at any time that FEI has surplus storage capacity relative to projected loads, FEI may elect to sell its inventory to a third party who will pay a premium, and return the inventory to FEI at a future date. This is referred to as a "loan" transaction.	calculated, rather the use of the storage under the CPA is part of FBC's overall optimization and allows FBC the ability to increase PPA Energy and PPA Capacity displacements or increase surplus sales, and the value is captured in the Eligible Mitigation Benefit calculation.

102.23.1 As part of the above response, please provide a detailed comparison of FBC's proposed PSI to FEI's GSMIP.

Response:

The GSMIP and PSI are not directly comparable, except at a high level. Both are incentives that reward the utility for providing value to the customer. Both are designed and consistent with the guiding principles from BCUC Order G-26-11, but both are substantially different in the details. Their structure, design, and calculation are both different, as would be expected for two separate companies operating with two distinct commodity markets and available resources.

The incentive received under the GSMIP and proposed incentive received under the PSI are generally calculated based on a percentage of mitigation benefit delivered to the customer, which ensures that the Company is only receiving a benefit if the customer is also benefiting. One main difference is that FEI's GSMIP is separated into benchmarked activities, non-benchmarked activities and new activities, each having a different formula to calculate the incentive. FEI's benchmarked activities are cost mitigation activities for which a reasonable market benchmark has been established. For benchmarked activities, three performance factors have been derived to ensure that FEI maintains a high level of performance. These include a pricing measure to establish performance against a base utility benchmark, and capacity, and market concentration factors. Benchmarked activities include daily transportation mitigation, transportation capacity releases, and spot commodity resales. Non-benchmarked activities are cost mitigation activities for which no reasonable market benchmark has been established against which to measure FEI's performance. Currently non-benchmarked activities

include: T-North transportation, T-South Interior transportation, NOVA transportation, liquids extraction, NOVA forward capacity releases, T-South Interior capacity releases, NOVA Pooling, Transportation Asset Management Agreement, storage activities and forward commodity resales. Furthermore, the GSMIP provides for the highest incentive for new activities, which encourages FEI to seek out new mitigation activities.

The PSI is designed differently. FBC currently has only three main areas of mitigation - displacing BC Hydro PPA Energy, displacing BC Hydro PPA Capacity and selling surplus capacity. There is no reasonable benchmark for these activities, and therefore these would all be considered non-benchmarked activities. Under the proposed PSI, any new activities would be subjected to the same formula, and would not receive a higher share for new activities. The proposed PSI does not have any benchmarked activities. The following table shows the different formulas for incentives under the GSMIP and PSI.

	GSMIP Incentive Percentage	**PSI Incentive Percentage**
Benchmarked Activities (MPF[1] between 100%-131%)	2.45% + 0.05% * (MPF – 100)	N/A
Benchmarked Activities (MPF between 131% - 136%)	4.00%	N/A
Benchmarked Activities (MPF of 136% and greater)	4.00% + 0.04% * (MPF – 136)	N/A
Non-Benchmarked Activities	4.00%	10% of mitigation above $7.5 million
New Activities	12.00%	10% of mitigation above $7.5 million

[1]Market Performance Factor is calculated by dividing the actual mitigation revenue by the base utility benchmark revenue, as detailed in the GSMIP Term Sheet, most recently attached to the GSMIP Winter Report, filed with the BCUC on May 29, 2019.

As shown in the response to BCUC IR 1.102.3, the FBC incentive received under the proposed PSI would have ranged from 0 percent to 6.8 percent over the term of the Current PBR Plan.

102.24 Based on FortisBC's experience and understanding, to what extent are the gas and electricity commodity markets similar or different in BC? Please discuss.

Response:

The gas and electricity commodity markets in BC are different in that they do not share the same defining characteristics.

The production and the transmission of these commodities are different. The electric market requires generation and demand to match at all times, and the supply stack in the Pacific Northwest region includes different types of generation resources that may be dispatched quickly to help ensure that there are sufficient resources available to meet demand. The marginal resources has a significant impact on the real-time electricity price. The electric market is traded on an hourly or sub-hourly market (the California Energy Imbalance Market

trades in 15 minute increments). The gas market, on the other hand, does not have the same short-term changes to the supply resources. The gas market benefits from storage availability in their ability to increase the pressure in the line, storing more gas for later delivery. The gas market is typically traded on a daily basis, or partial day basis. The gas market is significantly larger in BC and Alberta, creating more liquidity for forward contracts, and more counterparties to transact. For forward market purchases, there are similar issues between the markets, and differences in the liquidity of the market, available products, and counterparties. The electric market is generally more volatile due to variations in renewable generation availability, lack of available storage, less liquidity for forward contracts and the instantaneous nature of the delivery.

While there are actively traded gas market hubs in BC, such as Station 2 and Huntingdon/Sumas, there are no active trading market hubs for electricity in BC. FBC can purchase power at the Mid-Columbia (Mid-C) market hub, located on the Columbia River on the border between Washington and Oregon, and purchase transmission to deliver the electricity to the FBC service area for their customers. Both the gas and electric markets are heavily impacted by transmission availability. Transmission issues from the Mid-C to the FBC service area can impact FBC's ability to access market power, and transmission issues in the Pacific Northwest are a significant factor in the real-time price at Mid-C. The gas market in BC is heavily reliant on the Enbridge pipeline for the main source of supply from Northeast BC to the Sumas trading hub. Despite these locational differences, the gas and electricity prices at Huntingdon/Sumas and Mid-C have been highly correlated in the past, particularly during peak winter demand periods in the Pacific Northwest. This is because natural gas fired power plants are often the marginal source of generation in the region that sets market electricity prices – the variable cost of natural gas fuel for these power plants directly influences the electricity price.

On page 5 of the BCUC's Decision on the 2016 Long Term Electric Resource Plan and Long Term DSM Plan (FBC 2016 LTERP and LT DSM Plan), it states the following:

> FBC states that relying on market purchases over the long-term can be risky in terms of price and supply availability. FBC elaborates that:
>
> > [W]hile there are market price forecasts for future electricity prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the marketplace….There is also no guarantee that FBC will be able to access market supply reliably, especially if there is no access to long term firm transmission.

In FBC's view, market supply is relied upon as a Planning Reserve Margin (PRM) resource to meet unforeseen increases in demand or forced plant outages, and if increased amounts of market supply were also relied upon as a base resource in the preferred portfolio to meet expected gaps, then the PRM test could fail. Specifically, FBC states in its PRM report that it only has 150 MW (225 MW in June) of reliable access to the US market over Line 71, however the PRM report did not specify whether there was a similar limit on purchases of BC Hydro surplus energy.[144]

102.25 With reference to the above, please explain how FBC plans to address any power supply and reliability risks resulting from its increased optimization activities that may be achieved under the proposed PSI.

Response:

The PSI and the MRP have been designed with safeguards to ensure that power supply and reliability risks are not impacted by the proposed PSI. These include:

1. FBC's current optimization activities are completed in the short term, with no long-term impacts to available resources. The optimization activities do not involve FBC relying on the market for meeting peak demand over the long term. The underlying resources (such as the BC Hydro PPA and WAX capacity) remain in place and are available to be utilized on a day-ahead planning basis if they are required. Therefore, the optimization activities do not increase any power supply or reliability risks, including the Planning Reserve Margin test.

2. FBC Annual Electric Contracting Plan is approved by the BCUC including any new optimization activities that may be included in the PSI, prior to their implementation. A key objective of the PSI is to ensure security of supply. Therefore, it is very unlikely that any new activity would have any impact to the reliability of FBC's power supply.

3. The incentive proposed provides the majority of the optimization benefits to customers and provides a direct link between the benefits and reward for optimization activities. This design ensures that the PSI is less susceptible to produce unintended consequences and is largely free of external influences.

4. A broad range of service quality indicators are included in the MRP to ensure that an appropriate level of service is maintained by FBC, including reliability metrics (SAIDI and SAIFI). Failure to meet the benchmark thresholds could represent a degradation in service quality and may result in a penalty. FBC has established a strong record of maintaining service quality to customers.

[144] FBC 2016 LTERP and LT DSM Plan Decision, p. 5 and Order G-117-18.

5. FortisBC has proposed to continue with the robust Annual Review process designed by the BCUC for FEI and FBC's current PBR Plans, which provides an opportunity for ongoing evaluation of FEI's and FBC's performance under the MRPs. If FEI or FBC were shifting its focus away from certain areas of its business, there would be an annual opportunity for corrective measures to be taken by the BCUC over the term of the MRP.

102.26 Please explain how the increased optimization activities would affect the Planning Reserve Margin test.

Response:

Please refer to the response to BCUC IR 1.102.25.

J. POLICIES AND SUPPORTING STUDIES

103.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.3, p. D-15

Amortization of Contributions in Aid of Construction (CIAC)

With respect to FEI, on page D-15 of the Application FortisBC states the following:

> 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 for Distribution CIAC and 1.46 percent 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 respect to FBC, on page D-30 of the Application FortisBC states the following:

> 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.

103.1 Please clarify whether FEI and FBC record or track CIAC only at the Distribution/Transmission CIAC level, or do FEI and FBC also track CIAC at the level of the specific asset types?

Response:

FEI and FBC record and track CIAC at the broader distribution and transmission levels, rather than the specific asset class types described in the preamble to this IR. Recording CIAC at the broader reporting level of Distribution/Transmission is consistent with how FortisBC maintains its accounting records for CIACs, is consistent with FortisBC's previous depreciation studies approved by the BCUC, and is consistent with the notion of the group method of depreciation for utilities.

Additionally, CIAC amortization is calculated on a weighted average method thus mitigating the CIAC amortization difference between tracking CIAC at the specific asset class type level as compared to the broader categories currently used. In determining the weighted average method, FortisBC aggregates the opening gross plant of several specific asset classes subject to CIAC and then multiplies by the proposed depreciation rate, and then the total calculated

depreciation expense is divided by the total cost of those assets to determine the weighted average CIAC depreciation rate.

CIAC is difficult to track at the asset class type level because of the increased complexity required to allocate contributions to multiple CIAC asset classes. Tracking at the asset class type level would also result in an increased number of CIAC asset classes to be maintained by FortisBC's accounting department and would require reconfiguration of the capital asset subledger within the SAP system.

While the CIACs are not accounted for at the asset class type level, both FEI and FBC record and track CIAC based on the type of the contribution received. In FEI, the CIAC Distribution asset class contains contributions received for the construction of Distribution Mains, Services and Meter Installation costs and the CIAC assets are recorded and tracked based on the type of the contribution received. Examples include CIAC received from excess service line charges, billable alterations, main extensions, meter and regulating equipment work, etc. The CIAC Transmission asset class contains contributions received for the construction of Transmission Pipeline only. In addition to these two CIAC asset classes, FEI also tracks the contributions received for the construction of Natural Gas for Transportation and Biomethane fixed assets in separate CIAC asset classes.

In FBC, the CIAC Distribution asset class contains contributions received for New Connections and Forced Upgrades for the construction of Distribution Poles, Towers and Fixtures, Distribution Conductors and Devices, Distribution Line Transformers and Distribution Meters plant.

103.1.1 If CIAC is only tracked at the Distribution/Transmission level, please explain why CIAC is not tracked at the asset type level.

Response:

Please refer to the response to BCUC IR 1.103.1.

103.1.2 If CIAC is tracked at the asset type level, please explain why the recommended depreciation rate for the specific asset type is not used for the corresponding CIAC, instead of the average of the

recommended rates. Please recalculate the amortization of CIAC using the recommended depreciation rates for each asset type.

Response:

Please refer to the response to BCUC IR 1.103.1.

103.2 Please provide a comparison of FEI and FBC's method(s) of amortizing CIAC with the methods used by other Canadian peers.

Response:

FortisBC has prepared a sample comparison of CIAC amortization methodology amongst other Canadian peers below.

Utility	CIAC Depreciation method
FortisBC Energy	Weighted average - excluding provision for net salvage
FortisBC Inc	Weighted average - excluding provision for net salvage
Fortis Alberta	Weighted average - excluding provision for net salvage
ATCO Electric	Weighted average – excluding provision for net salvage
NB Power	Weighted average – excluding provision for net salvage
Manitoba Hydro	Weighted average – excluding provision for net salvage
Enbridge Gas Distribution	Weighted average – excluding provision for net salvage
Pacific Northern Gas	Weighted average
BC Hydro	CIAC is tracked on asset class level and it uses the depreciation rate of the asset class for which the CIAC is received
ATCO Gas	CIAC is tracked on asset class level and it uses the depreciation rate (excluding provision for net salvage) of the asset class for which the CIAC is received
ATCO Pipelines	CIAC is tracked on asset class level and it uses the depreciation rate of the asset class for which the CIAC is received
AltaGas Utilities Inc.	CIAC is recorded as a reduction of the corresponding asset balance and amortized together with the related asset
TransCanada Pipeline	CIAC is recorded as a reduction of the corresponding asset balance and amortized together with the related asset, CIAC is not tracked separately
ENMAX Power	CIAC is recorded as a reduction of the corresponding asset balance and amortized together with the related asset, CIAC is not tracked separately
Energir (Gaz Metro)	Depending on the circumstances: Weighted average, CIAC is tracked on asset class level and uses the depreciation rate of the asset class for which the CIAC is received, or CIAC is recorded as a reduction of the corresponding asset balance and amortized together with the related asset

As shown from this comparison, there is diversity in practice. There are three methodologies identified:

1. weighted average method, excluding provision for net salvage;
2. CIAC tracked on asset level and uses the same depreciation rate as the asset class for which the CIAC is received; and
3. CIAC being recorded as a reduction of the corresponding asset balance and amortized together with the related asset.

Depending on the specific circumstances of the CIAC received, it is expected that each utility would apply the CIAC amortization method that is most representative and applicable to its individual situation, which would include its internal accounting processes and ERP system configuration. FortisBC is intending to continue to record CIAC amortization based on the weighted average method which is consistent with its previous practice and the current configuration of its asset accounting subledger.

103.3 Please explain if the calculated average amortization rate is based upon a weighted-average, or a simple average, and provide the calculations.

Response:

The amortization rate for both FEI and FBC Distribution and Transmission CIAC is derived based on a weighted-average calculation.

The calculations for each CIAC category, using the weighted-average method, are provided in the tables below.

FEI Distribution CIAC weighted average depreciation rate calculation (in $000s)

Class	Description	2017 Depreciation study Rate	Opening balance 2018	Depreciation Based on 2017 Depreciation study Rate
473-00	DS Services	2.18%	1,158,187	25,248
474-00	DS Meters/Regulators Installations	7.45%	187,875	13,997
475-00	DS Mains	1.35%	1,424,762	19,234
		b / a	*a*	*b*
CIAC	**Distribution Weighted Average rate**	**2.11%**	**2,770,824**	**58,479**

FEI Transmission CIAC weighted average depreciation rate calculation (in $000s)

Class	Description	2017 Depreciation study Rate	Opening balance 2018	Depreciation Based on 2017 Depreciation study Rate
465-00	TP Transmission Pipeline	1.46%	1,224,681	17,880
465-11	IP Transmission Pipeline (Whistler Pipeline)	1.54%	42,296	651
		b / a	*a*	*b*
CIAC	**Transmission Weighted Average rate**	**1.46%**	**1,266,977**	**18,532**

FBC Distribution CIAC weighted average depreciation rate calculation (in $000s)

Class	Description	2017 Depreciation study Rate	Opening balance 2018	Depreciation Based on 2017 Depreciation study Rate
364.00	Poles, towers and fixtures	1.75%	205,785	3,601
365.00	Conductors and devices	1.54%	332,125	5,115
368.00	Line transformers	2.31%	152,641	3,526
370.10	AMI Meters	6.25%	37,461	2,341
		b / a	*a*	*b*
CIAC	**Distribution Weighted Average rate**	**2.00%**	**728,013**	**14,583**

The one exception to using a weighted average rate for CIACs is the Natural Gas for Transportation and Biomethane CIAC asset classes in FEI. These asset classes are not using a weighted average rate, but rather are using the specific depreciation rates recommended in the FEI 2017 Depreciation Study performed by Concentric Advisors.

For Natural Gas for Transportation, the contributions received relate to the following asset classes: 476.10/476.20 - Natural Gas for Transportation CNG/LNG dispensing equipment, 476.30/476.40 - CNG/LNG foundation and 476.60 CNG dehydrator. As each asset class has a recommended depreciation rate of 5 percent, the Natural Gas for Transportation CIAC also has a depreciation rate of 5 percent. For Biomethane, the contributions received relate to asset class 418.20 Biogas Purification Upgrader only, which has a recommended depreciation rate of 4.89 percent. Therefore, the Biomethane CIAC asset class also has a depreciation rate of 4.89 percent.

104.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.4.1, p. D-17

Option 1: Conversion to Equal Life Group (ELG) without Componentization

On page D-17 of the Application, FortisBC states the following:

> 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.

104.1 Please explain how FEI currently accounts for gains or losses on retirements. Do these amounts appear in this study?

Response:

Gains and losses resulting from historical assets retirements are recorded as a credit or debit, respectively, in accumulated depreciation for the specific asset class to which they relate. This treatment is discussed in the BCUC Uniform System of Accounts for Gas Utilities pages 17 through 21.

When a depreciation study is conducted on a three to five year cycle, the revised depreciation rates will reflect the unwinding of the difference between the net book value of assets and the value realized at retirement that is embedded in accumulated depreciation. This is accomplished by setting depreciation rates to true up the depreciation reserve, if required. This mass property accounting methodology for gains and losses on retirements is consistent with the group method of depreciation adopted by many utilities (including FortisBC) and is also discussed on pages 23 through 26 in the BCUC Uniform System of Accounts for Gas Utilities.

In the FEI 2017 Depreciation Study, on pages 5-2 and 5-3 of Appendix D2-1 in the Application, the gains and losses are included in column 5, labelled Book Depreciation Reserve. Note that the majority of the Book Depreciation Reserve is representative of the accumulated depreciation collected in customer rates, with a portion representing gains and losses on retirements. The unwinding of the accumulated gains and losses included in the Book Depreciation Reserve were taken in consideration when the recommended depreciation rates, on pages D-3 to D-7 in Section D2.2.1 of the Application, were developed.

105.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.4, pp. D-21 –D-23

Proposal to Continue to use Average Life Group (ALG)

On page D-23 of the Application, FortisBC states the following:

> 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.

On pages D-21 and D-22 of the Application, FortisBC provides Table D2-7 which summarizes the depreciation methods used by "Large Canadian Natural Gas Distribution Utilities."

105.1 Please provide the frequency of depreciation studies for each of the utilities listed in Table D2-7 that uses the ALG method.

Response:

FortisBC does not have the insight into each of the utilities' specific practices or approach to frequency of depreciation studies. However, based on general industry knowledge and discussion with Concentric Advisors, three to five years is a reasonable time gap between depreciation studies when the ALG method is used. There is no required frequency of performing a depreciation study under the ALG method.

105.2 Historically, has FEI always performed depreciation studies every three to five years? Please provide the dates of the last three depreciation studies.

Response:

Over the last twelve years, FEI has performed depreciation studies every three to five years. In addition to the FEI 2017 Depreciation Study included in the Application, the previous depreciation studies were filed as follows:

- 2014 Depreciation Study dated August 21, 2015 – filed in the FEI Annual Review for 2016 Delivery Rates.

- 2009 Depreciation Study dated April 18, 2011 – filed in the FortisBC Energy Utilities 2012-2013 Revenue Requirement Application.

- 2007 Depreciation Study dated October 10, 2008 – filed in the Terasen Gas Inc. 2010-2011 Revenue Requirement Application.

105.3 Please explain how FEI determines when to conduct a depreciation study.

Response:

As part of the FEU 2012-2013 Revenue Requirement Application, FEI committed to filing an updated depreciation study within three to five years from the last approved depreciation study. Periodic depreciation studies are good business practice and necessary to properly update depreciation rates to reflect the assets' useful lives and to ensure a fair allocation and recovery of depreciation expense between current and future ratepayers. This is also consistent with Concentric's (previously Gannett Fleming) recommendation[145] that depreciation studies be completed every three to five years to re-evaluate depreciation rates.

If there were a series of significant and unplanned retirements, FortisBC would consider whether the previous depreciation rates continue to reflect a reasonable estimate of the assets' remaining lives or whether an updated depreciation study is warranted.

While the decision to conduct a depreciation study is not based on a specific threshold of accumulated gains/losses on retirements, one of the benefits of performing an updated depreciation study every few years allows for the timely unwinding of gains/losses when developing revised depreciation rates.

From an external financial reporting perspective, reporting entities that apply the group method of depreciation are expected to update depreciation studies on a regular basis for the reasons discussed above.

[145] FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application, Section 5: Cost of Service, page 283.

105.3.1 As part of the above response, please explain if the decision is based on surpassing a threshold of gains/losses on retirements. If so, what is this threshold? Please explain in detail.

Response:

Please refer to the response to BCUC IR 1.105.3.

On page D-22 of the Application, in reference to Table D2-7, FortisBC states the following:

> 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)….
>
> … 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.

105.4 Please explain why AltaGas Utilities Inc., Energir (Gaz Metro), Heritage Gas Ltd., and Union Gas all use the ELG method, given that US GAAP is the accounting standard used these utilities.

Response:

FEI asked Concentric to comment, but was informed that Concentric cannot provide comment on the depreciation policies of other Canadian clients without the written consent of the utility. Concentric has not received such consent and therefore cannot respond to this request. Furthermore, Concentric did not complete the Union Gas depreciation study, and therefore cannot comment on their accounting and depreciation policies.

Further, although FortisBC also does not have all the rationale and details for the above-mentioned US GAAP reporting utilities using the ELG method, based on publicly available information, FortisBC believes that one of the utilities may have utilized the ELG method since inception, regardless of Canadian GAAP or US GAAP. Another utility appears to have converted from ALG to ELG as part of their original plan to transition to IFRS; however, they subsequently ended up continuing to report under US GAAP.

In general, while utilities that have adopted IFRS are more likely to use ELG, it is not inappropriate or prohibited for utilities accounting under US GAAP to use the ELG method. Rate-regulated accounting is a permanent and well-established standard under US GAAP, including group depreciation methods for utilities. Therefore, there is greater acceptance for either the ELG or ALG depreciation methodologies under US GAAP.

105.5 For each of the utilities that are listed as using the ELG method, please specify whether the utility uses option 1 (ELG without componentization), or option 2 (ELG with componentization).

Response:

With the exception of Manitoba Hydro that is using option 2 (ELG with componentization), the remaining utility companies listed in Table D2-7 of the Application are using option 1 (ELG without componentization). It is FortisBC's understanding that those utilities that are utilizing ELG without componentization have been doing so since inception. Additionally, they are required to perform an incremental annual test that 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" as described on Page D-17 of the MRP.

106.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.4.3, pp. D-20 – D-21

Comparison of ELG and ALG

On page D-20 of the Application, FortisBC states the following: "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."

In Table D2-6 on page D-21 of the Application, FortisBC compares the high-level impact on depreciation expense using the ELG method (assuming no componentization is done) versus the ALG method. If the ELG method were to be used, FortisBC estimates an increase to depreciation expense, including net salvage and CIAC, of $24.3 million, which FortisBC states "would result in a delivery rate increase of approximately four percent."

106.1 Please clarify if the four percent delivery rate increase is net of the overall impact on rate base.

Response:

Confirmed.

106.1.1 If no, please estimate the net impact to rates over the proposed MRP term if ELG were to be adopted, factoring in the impact of the higher depreciation expense on net rate base.

Response:

Please refer to the response to BCUC IR 1.106.1.

107.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.1, p. D-3; Exhibit B-1-1, Appendix D2, FEI Depreciation Study

Depreciation Rates

On page D-3 of the Application, FEI states the following:

> 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.

107.1 Please provide the accounts, and surpluses, that result in the downward pressure on depreciation rates. Please explain the cause(s) of the surpluses in each of these accounts.

Response:

In total, of the 84 accounts reviewed in the FEI 2017 Depreciation Study (refer Table D2-3 in the Application), 27 accounts are in surplus positions while the other accounts are in a deficit. The accounts with surpluses that result in the downward pressure on depreciation rates are summarised in the table below. The detailed tables for each of the listed accounts are provided in Section 8 - Detailed depreciation calculation, pages 8-1 to 8-69 from the FEI 2017 Depreciation Study, Appendix D2-1.

Class	Description	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Surplus +	2014 rate	2017 rate	Curve 2014	Curve 2017
401-01	Franchises and Consents	149,344	212,425	63,081	5.39%	1.08%	40-SQ	40-SQ
442-00	LNG Gas Structures	2,914,137	3,777,256	863,119	3.03%	2.20%	25-L2	25-L2
443-00	LNG Gas Equipment	11,193,427	12,714,626	1,521,199	1.88%	1.23%	40-S4	40-L4
449-00	LNG Gas Other Equipment	15,861,161	16,751,489	890,328	3.83%	2.77%	27-R3	27-R3
442-01	LNG Gas - Structures Mt Hayes	4,453,495	4,695,958	242,463	3.88%	3.85%	25-R3	25-L2
448-10	LNG Gas - Piping Mt Hayes	1,848,608	1,918,726	70,118	2.46%	2.45%	40-R3	40-R3
448-20	LNG Gas - Pre-Treatment Mt Hayes	7,344,587	7,687,309	342,722	3.88%	3.84%	25-R3	25-R3
448-40	LNG Gas - Send Out Equipment Mt Hayes	3,379,116	3,844,261	465,145	2.44%	2.41%	40-R2	40-R2
448-50	LNG Gas - Sub-Station and Electrical Mt Hayes	3,461,508	3,670,077	208,569	2.44%	2.41%	40-R2	40-R2
448-60	LNG Gas - Control Room Mt Hayes	2,266,731	2,613,477	346,746	6.30%	6.09%	15-R3	15-R3
467-00	LNG - Measuring and Regulating Equipment Mt Hayes	747,341	1,325,099	577,758	2.58%	2.34%	36-S0.5	36-S0.5
463-00	TP Meas/Reg Structures	6,558,506	7,328,222	769,716	2.29%	2.13%	38-S2	38-S2
466-00	TP Compressor Equipment	81,842,106	90,769,657	8,927,551	2.89%	2.42%	35-R4	40-R4
467-10	TP Meas/Reg Equipment	18,282,722	25,606,363	7,323,641	2.41%	2.12%	36-S0.5	40-R1.5
467-20	TP Telemetry Equipment	7,649,652	8,190,973	541,321	9.75%	8.97%	8-L1	10-L1.5
468-00	TP Communications Equipment	2,663,462	3,765,245	1,101,783	0.56%	0.00%	19-R3	19-R3
467-31	IP Meas/Reg Equipment (Whistler Pipeline)	70,413	95,978	25,565	2.55%	2.26%	36-S0.5	36-S0.5
472-00	DS Structures	7,259,637	9,391,375	2,131,738	2.41%	2.15%	36-R1.5	38-R1.5
475-00	DS Mains	453,753,892	499,802,391	46,048,499	1.54%	1.35%	64-R2.5	65-R2.5
477-10	DS Meas/Reg Additions	43,950,943	54,289,435	10,338,492	3.05%	2.51%	30-R2	33-R2
472-20	Biogas - Structures and Improvements	57,827	74,106	16,279	2.72%	2.69%	36-R1.5	36-R1.5
477-40	Biogas - Reg and Meter Equipment	209,841	289,121	79,280	3.24%	3.22%	30-R2	30-R2
478-30	Biogas - Meters	5,532	8,734	3,202	5.02%	4.89%	18-R2.5	18-R2.5
482-10	GP (Frame) Structures	7,301,562	8,955,879	1,654,317	6.04%	3.17%	20-R2.5	25-R1.5
482-20	GP (Masonry) Structures	20,387,326	27,360,805	6,973,479	1.95%	1.52%	50-R2.5	60-R2
485-10	GP Heavy Work Equipment	320,148	486,811	166,663	6.38%	5.14%	12-L0.5	13-L0.5
485-20	GP Heavy Mobile Equipment	1,408,704	2,686,800	1,278,096	9.85%	6.09%	8-L2	9-L1.5

With the exception of ten accounts where the service lives have been extended (listed below), the downward pressure on the depreciation rates on the remaining accounts is the result of the actual booked depreciation reserve being in a surplus position (i.e., allocated actual booked amount higher than calculated accumulated depreciation in table above). The decrease in the recommended depreciation rates is required to correct the allocated actual booked amount balance to the calculated accumulated depreciation balance.

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 regular basis is to recommend depreciation rates that will prospectively unwind such variances. Further, as noted on page D-3 of the Application, the surpluses are partially attributable to the one-year delay in implementing the recommended depreciation rates from the 2014 Depreciation Study.

For the ten accounts with surpluses where longer service lives based on actual retirement history are expected, additional discussion and reasons are provided in the table below:

Class	Description	Curve 2014	Curve 2017	Increase in service life	Reason
466-00	TP Compressor Equipment	35-R4	40-R4	+5	Increase in average age of retirement transactions in the past 3 years, more in line with industry trends and true-up for the depreciation rate over the remaining life of the assets
467-10	TP Meas/Reg Equipment	36-S0.5	40-R1.5	+4	FEI operations and management group suggested that the life of this account is expected to lengthen going forward, estimates among peers ranged from 35 to 45 years and true-up for the depreciation rate over the remaining life of the assets
467-20	TP Telemetry Equipment	8-L1	10-L1.5	+2	Overall increase in the percent of assets surviving past 8 years and true-up for the depreciation rate over the remaining life of the assets
472-00	DS Structures	36-R1.5	38-R1.5	+2	Overall increase in the percent of assets surviving past 36 years and true-up for the depreciation rate over the remaining life of the assets
475-00	DS Mains	64-R2.5	65-R2.5	+1	Increase in average age of retirement transactions in the past 3 years, recommendation that the life of mains should be on the longer end of the range experienced by peer utilities (61-68 years) and true-up for the depreciation rate over the remaining life of the assets
477-10	DS Meas/Reg Additions	30-R2	33-R2	+3	FEI operations and management group suggested that the life of this account is expected to lengthen going forward, estimates among peers ranged from 33 to 50 years and true-up for the depreciation rate over the remaining life of the assets
482-10	GP (Frame) Structures	20-R2.5	25-R1.5	+5	Increase based on management expectations that the average life to be 25 years and true-up for the depreciation rate over the remaining life of the assets
482-20	GP (Masonry) Structures	50-R2.5	60-R2	+10	Increase based on management expectations that the average life to be 60 years and true-up for the depreciation rate over the remaining life of the assets
485-10	GP Heavy Work Equipment	12-L0.5	13-L0.5	+1	As per FEI fleet management recommendation and true-up for the depreciation rate over the remaining life of the assets
485-20	GP Heavy Mobile Equipment	8-L2	9-L1.5	+1	As per FEI fleet management recommendation and true-up for the depreciation rate over the remaining life of the assets

1

107.2 Please comment on whether or not the risk of stranded assets has changed due to the updated service lives and rate changes.

Response:

FortisBC does not believe the risk of stranded assets has been impacted by the updated service lives and depreciation rate changes recommended in the depreciation studies. The ten asset classes whose lives were extended as described in BCUC IR 1.107.1 are not considered as having stranded asset risk at this time. Stranded assets are dependent on factors like technological changes, operational requirements and changes in FortisBC's operating environment (i.e., changes in government policy). Please refer to the response to BCUC IR 1.2.4 discussing how FortisBC manages any risk of stranded assets.

The 2017 Depreciation Studies included in the MRP included the re-evaluation of existing depreciation rates for accuracy, reasonableness and applicability to assets with the rates. This process, performed every three to five years as recommended by Concentric, is designed to recover the cost of the assets over their remaining lives and re-evaluate the appropriateness of the assumed lives of the assets.

107.2.1 Notwithstanding FEI's response to the above IR, how does FEI manage the risk of stranded assets? Please discuss.

Response:

Please refer to the response to BCUC IR 1.2.4. Depreciation studies are one of the ways in which utilities can "Develop pathways to pay for the early retirement of assets" as discussed in that response.

On page C-80 of the Application, FEI describes the AMI Major Project anticipated to be filed during the proposed MRP term.

107.3 Please explain in detail the impact, if approved, the AMI project would have on depreciation rates (in future depreciation studies) and asset retirement losses.

Response:

FEI has not yet determined how the proposed AMI project will affect future depreciation studies. The proposed treatment for the depreciation or disposal of existing meters would be included in the AMI CPCN and any impacts to depreciation rates would need to be considered at that time. Once a proposed disposition method is established, and FEI has complete information on the impacts of new AMI meters, FEI will be better able to comment on any effects on future depreciation studies and asset retirement losses. Accordingly, the FEI 2017 Depreciation Study rates do not take into account the asset retirements associated with an AMI project since this will be the subject of a separate proceeding.

107.4 Please explain how FEI would propose to treat the disposal of existing meters if the AMI project is approved.

Response:

Please refer to the response to BCUC IR 1.107.3.

108.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-5

Account 449.00 – LNG Plant – Other Equipment

On page 3-5 of the Depreciation Study for FEI, Concentric states the following:

> Interviews with FortisBC Energy operations and management staff have indicated that the statistically indicated average service life of 33 years for the equipment in this account is not consistent with their expectations. Concentric viewed that the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, maintaining the currently approved Iowa 27-R3 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

108.1 Please provide a copy of the interview notes with FortisBC staff and explain in detail how these discussions supported maintaining the use of the Iowa 27-R3 curve, rather than changing to the statistically indicated average service life of 33 years.

Response:

The relevant interview notes taken on October 16, 2018 for discussion of account 449.00 LNG – Other equipment are provided below:

> Confirmed with FEI operations and management that 27 year life continues to be representative for the type of assets residing into asset class 449.00 LNG – Other equipment. Suggested to leave the current approved Iowa 27-R3 for another term until next depreciation study is conducted because of some potential LNG equipment retirements that could be expected in the future.

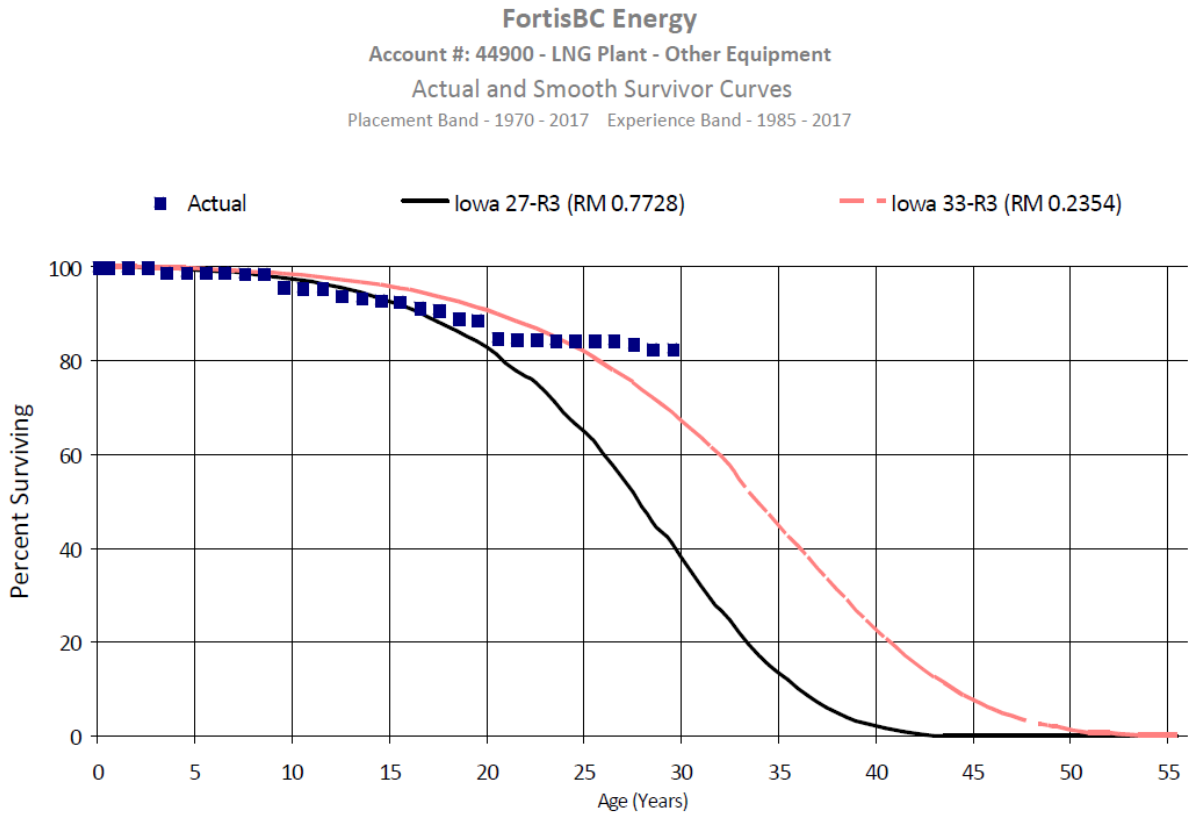
While FortisBC considers the statistically indicated average service life as a strong indicator of the depreciation curve to apply, it does take into account other qualitative factors such as those mentioned in the interview notes. In addition, FortisBC considered that an estimated 27 year life was used for the past three depreciation studies (2009, 2014 and 2017). The depreciation rate for the account 449.00 has declined from 4.24 percent (2009) to 3.83 percent (2014) to 2.77 percent (2017) as a result of trueing up the “Book depreciation reserve” and to ensure proper future recovery of the remaining investment into this account.

108.2 Please provide the residual measure for the Iowa 27-R3 curve and compare it to the residual measure if a best-fit Iowa curve with an average service life of 33 years was used for Account 449.00.

Response:

The following response has been prepared by Concentric.

Shown in the below table is the comparison between Iowa 27-R3 and Iowa 33-R3 curves for account 449.00 – LNG Plant – Other Equipment.



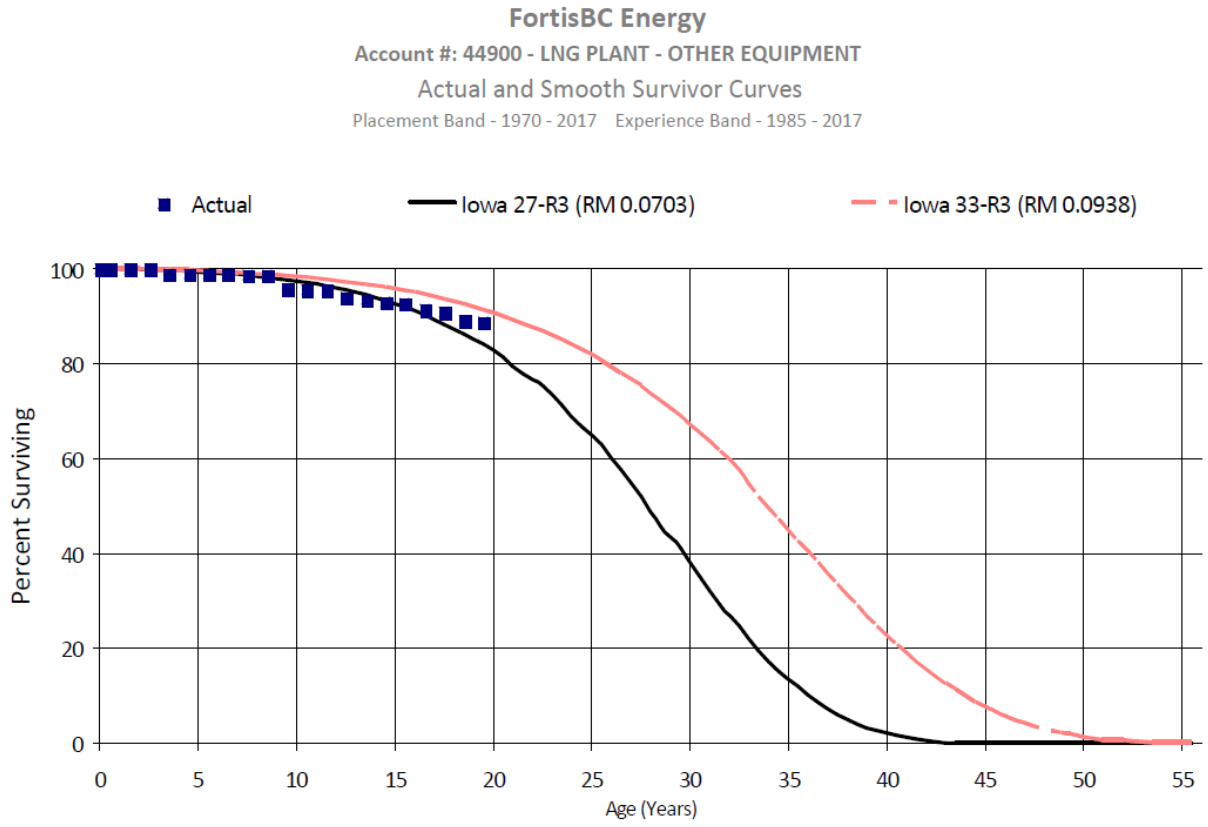
As detailed on page 3-2 of the FEI depreciation study:

> The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion ("residual measure"). The residual measure is based on a least square solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve. The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate,

shown in the output format is the square root of this mean square. As such, the lower the residual measure, the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to 1 percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process.

Concentric will however recognize the observed data points beyond the 1 percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

The data (and calculations) that provide the percentage surviving for the graph on page 6-23 are detailed on page 6-22. Concentric views that the more relevant data points, which includes the bulk of exposures and retirements, are up to and including age 20.5. There is less significant data after age 20.5. As the residual measure calculation is based on a squared differences calculation, all calculations between the historical observed data and the Iowa curve being compared are weighted equally. Thus, fitting an Iowa Curve to the complete observed data up to age 29.5 will result in inappropriate longer lives. Performing a Residual Measure calculation up to age 20.5 will result in a better lower residual measure for the Iowa 27-R3 compared to the Iowa 33-R3 as shown in the below table.



108.3 Did Concentric undertake a review of peer companies for this account? If yes, please provide the average service life estimates for the peer companies. If no, please explain why not.

Response:

The following response has been prepared by Concentric.

Concentric had conducted a comprehensive peer analysis as shown in the table below. However none of the peer companies analyzed have comparable assets to Account 449-00. As such, there was not a peer review conducted for this account.

	PNG	AtcoGas	AltaGas	SaskEnergy	CentraGas	Enbridge
MANUFACTURING PLANT						
432 Structures						
433 Equipment						
434 Holders						
436 Compressor Equipment						
437 Measuring and Regulating Equipment						
LNG PLANT						
442 Structures						
442.01 Structures - Mt. Hayes						
443 Equipment						
443.05 Equipment - Mt. Hayes						
448.1 Piping						
448.2 Pre-Treatment						
448.3 Liquefaction Equipment						
448.4 Send Out Equipment						
448.5 Substation and Electrical						
448.6 Control Room						
449 Other Equipment						
449.01 Other Equipment - Mt. Hayes						
TRANSMISSION PLANT						
462 Compressor Structures	30-R4					
463 Measuring and Regulating Structures	39-R4		55-R3		65-R4	
464 Other Structures	30-R4					
465 Transmission Pipeline	65-R4		60-L3		65-R3	
465.11 Intermediate Pipe - Whistler						
465.3 Mains - Mt. Hayes						
466 Compressor Equipment	35-R3					
467 Measuring and Regulating Equipment - Mt. Hayes						
467.1 Measuring and Regulating Equipment	35-S2.5		45-S2.5		45-R2	
467.2 Telemetry Equipment						
467.31 Measuring and Regulating Equipment - Whistler						
468 Communications Equipment	15-R2					
DISTRIBUTION PLANT						
472 Structures	30-R3	55-R3	55-R3	40-R4	50-R3	60-S1.5
473 Services	50-R4	57-R2.5	50-R4	50-R3	62-R2	40-L1.5
474 Meter/Regulator Installations	40-R4	51-R3	48-R2	45-S2.5	50-R5	
474.02 New Meter Installations		15-R2				
475 Systems - Mains	65-R4	66-R2.5	62.5-R2	65-R4	68-R4	61-R3&55-R3
476 NGV Fuel Equipment						16-R3
477.1 Measuring and Regulating	35-R4	40-R2.5	50-R3	40-R4	37-R2.5	33-L1.5
477.2 Telemetry					17-S6	
478.1 Meters	20-R4	15-20R2	30-R2.5	25-R4	25-R1.5	20-S2
478.2 Instruments						
BIO GAS						
472.2 Structures and Improvements						
474.1 Meters/Regulator Installations						
475.1 Mains - Municipal Land						
477.4 Measuring and Regulating						
478.3 Meters						
418.1 Purification Overhauls						
418.2 Purification Upgrader						
NG FOR TRANSPORTATION						
476.1 CNG Disp Equipment						
476.2 LNG Disp Equipment						
476.3 CNG Foundation						
476.4 LNG Foundation						
476.5 LNG Pumps						
476.6 CNG Dehydrator						
GENERAL PLANT						
482.1 Stuctures (Frame)	30-R3	40-R2	75-R2	35-R2	45-R3	
482.2 Structures (Masonry)	30-R3	40-R2	75-R2	35-R2	45-R3	
483.1 Computer Hardware	5-SQ	10-R4	3&5-SQ	5-SQ		5-SQ
483.2 Computer Software (12.5%)	5-SQ	10-R4	3&5-SQ	5-SQ		4&5-SQ
483.25 RNG Computer Software (20%)						
483.3 Office Equipment	15-SQ	20-SQ	15-SQ	15-SQ	15-SQ	15-SQ
483.4 Furniture	15-SQ	20-SQ	15-SQ	15-SQ	15-SQ	20-SQ
484 Vehicles	8-L3	11-R2	7-L1.5	7-L2		11-L1.5
485.1 Heavy Work Equipment	18-R3	10-L2.5	14-L1	17-L2	20-R5	15-L2
485.2 Heavy Mobile Equipment						
486 Small Tools/Equipment		15-SQ	20-SQ	15-SQ	15-SQ	25-SQ
487.2 NGV Cyinders						7-S2.5
488.1 Telephone Equipment		15-SQ				10-SQ
488.2 Radio Equipment						

109.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-7

Account 465.11– Transmission Plant – Intermediate Pipe - Whistler

On page 3-7 of the Depreciation Study for FEI, Concentric states the following:

> This is a new account containing additions installed since 2008. There have been no recorded retirements at the time of this study. As these assets are new and have only been in service since 2008, there has not been enough time for a retirement rate analysis to be useful…
>
> …Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account.

109.1 Did Concentric undertake a review of peer companies for this account? If yes, please provide the average service life estimates for the peer companies. If no, please explain why not.

Response:

Confirmed, Concentric did undertake a review of peer companies for this type of account and the average service life estimates among those ranges from 60 through 65 years.

For clarification purposes, asset class 465.11 - Transmission Plant – Intermediate Pipe – Whistler was created as a sub-account of 465.00 - Transmission Pipeline for reporting purposes and contains the same type of assets as account 465.00. The average service life for account 465.11 - Transmission Plant – Intermediate Pipe – Whistler of 65 years is consistent with the service lives recommended for the other two similar accounts in FEI: 465.00 - Transmission Pipeline (65 years) and 465.30 Mains - Mt. Hayes (65 years).

110.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-12

Account 475.00– Distribution Plant – Systems – Mains

On page 3-12 of the Depreciation Study for FEI, Concentric states the following:

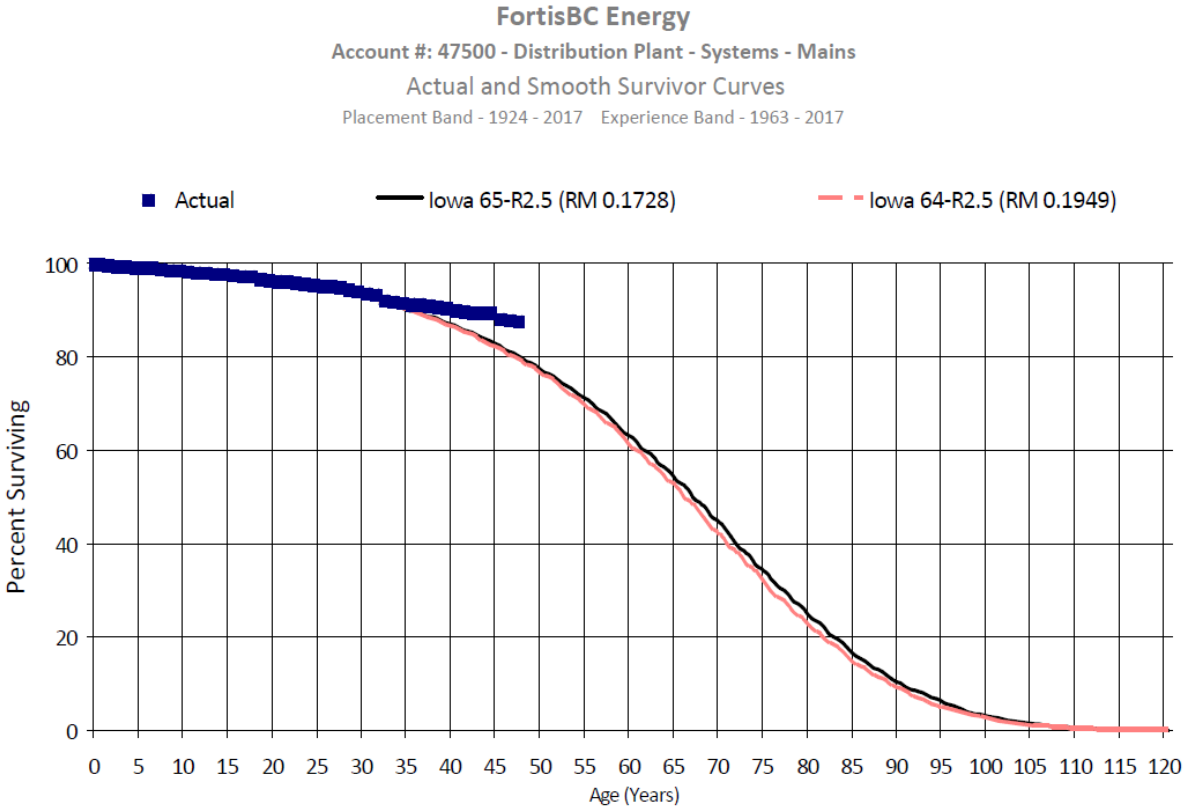
> The previous estimate for this account was the Iowa 64-R2.5 with a residual measure of 0.0810. Comments from the operations and management group suggested that the life of this account is expected to remain consistent going forward.
>
> Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 61 through 68 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R2.5, with a residual measure of 0.1728 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

110.1 Please explain in further detail why an Iowa 65-R2.5 is recommended, given the residual measure of 0.1728 is higher than the residual measure of 0.01810 for the existing Iowa 64-R2.5. Please provide a copy of the interview notes with management that Concentric used to support this recommendation.

Response:

The following response has been prepared by Concentric.

In responding to this question, Concentric notes that the statement “The previous estimate for this account was the Iowa 64-R2.5 with a residual measure of 0.0810” is incorrect in the filed depreciation report. The correct statement should have read: “The previous estimate for this account was the Iowa 64-R2.5 with a residual measure of 0.1949.” The Iowa curve and residual measures for both Iowa 64-R2.5 and Iowa 65-R2.5 are show in the table below. Given that the residual measure for Iowa 65-R2.5 is a better statistical fit than the currently approved 64-R2.5 and the 65-year life is closer to the expectation of operations and management staff, Concentric recommends a 65-R2.5 for this account.


FortisBC Energy
Account #: 47500 - Distribution Plant - Systems - Mains
Actual and Smooth Survivor Curves
Placement Band - 1924 - 2017 Experience Band - 1963 - 2017
Actual
Iowa 65-R2.5 (RM 0.1728)
Iowa 64-R2.5 (RM 0.1949)
Percent Surviving
100
80
60
40
20
0
0 5 10 15 20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
Age (Years)

1

2

111.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-14

Account 478.10– Distribution Plant – Meters

On page 3-14 of the Depreciation Study for FEI, Concentric states the following:

> The previous estimate for this account was the Iowa 18-R2.5, which does not provide a good fit to the historical retirement patterns in the early life with a residual measure of 1.0284. However, comments from the operations and management groups indicate that the historical data in this account is not expected to be indicative of future activity. It is expected that the life of this account will continue to shorten due to the Measurement Canada standards and the technological changes expected in the future.
>
> Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 15 through 30 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 18-R4, with a residual measure of 1.2579, is recommended for this account based on the indications from management and operations, and on the professional judgement of Concentric.

111.1 Please explain in further detail why an Iowa 18-R4 with a higher residual measure of 1.2579 provides a good fit, given that Concentric states an Iowa 18-R2.5 with a lower residual measure of 1.0284 does not provide a good fit. Please provide a copy of the interview notes with management that Concentric used to support this recommendation.

Response:

The following response has been prepared by Concentric.

Concentric notes that actuarial analysis was not considered in the development of this average service life estimate. While Concentric agrees that the Iowa 18-R4 is not a good fit to the historical data, Industry trends throughout Canada show that the life of metering accounts is shortening, and the manner under which metering assets retire has changed due to the implementation of Measurement Canada Standard S-S-06. Detailed interview notes are provided below.

Distribution Meters – Gas utility – Account 478.10

Measurement Canada standards are the biggest challenge at this time. FEI feels confident and comfortable with the number of meters being sampled, the S.S.06 challenges have been dealt with. FEI has not been granted an exemption from the new standards – the first seal period is 10 years, then 8 years, then 6 years.

FEI policy is to sample a year before they are due. This allows some flexibility in how to retest if too many meters fail the sample. This also helps with the work flow planning.

Gas meters are expected to pass the first 10 year period, and there is less certainty that they will pass the second period. Previous studies moved the life from 22 years to 20 years to 18 years.

111.2 Given management's views that the average life of this account will continue to shorten, were any Iowa curves with average service life estimates shorter than 18 years reviewed as an alternative to the existing Iowa 18-R2.5? If yes, please explain why these shorter lives were not recommended. If no, please explain why not.

Response:

The following response has been prepared by Concentric.

At the time of the study, peer natural gas distribution utilities had average service lives of 15 to 30 years, with 15 to 20 years being the most common throughout the natural gas distribution industry. The currently approved 18-year life fell well within that range. Measurement Canada Standard S.S.06 results in fewer interim retirements, with large numbers of meters retiring at age 10 and age 18, when the meters need to undergo mandatory sample testing. This results in an average service life of approximately 18 years for many utilities. Consequently, the Iowa curves considered for this account were 18-R2, 18-R2.5, 18-R3, and 18-R4.

112.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study p. 3-10

Account 474.00 – Distribution Plant – Meter/Regulator Installations

On page 3-10 of the Depreciation Study for FEI, Concentric states the following:

> Approximately 87 percent of this account relates to the installation costs of older gas meters which are due to be completely retired in 2035. The remaining 13 percent is related to station regulator assets. The investment relating to installation of meters costs follow an amortization accounting method and are expected to be completely retired in 2035 The remaining 13 percent of this account, relating to installation of station regulators, follow traditional regulatory retirement accounting practices and are expected to be in service until the end-of-life of the asset. At this time, Concentric recommends that the annual depreciation accrual should be weighted in accordance with the retirement practices for the two groups of assets in this account. With this approach, the resultant depreciation accrual rate will recognize the amortization accounting treatment related to meter installations and will also be applicable for the station regulators which will be retired in accordance with traditional regulatory accounting practices. There are detailed investment records for both groups of assets, therefore it is possible to calculate the depreciation accrual for both groups independently and then sum the depreciation accruals amounts to determine an overall weighted depreciation rate applicable to the account as a whole.

112.1 Please explain why the older gas meters and the station regulator assets are grouped together in the same account instead of each having its own account.

Response:

Installation costs for both meters and station regulators have historically been grouped together in previous rate filings with the BCUC and subject to a single depreciation rate. These items have been grouped together as the costs are similar in nature and determined to both fall under account 474-00 in the BCUC Uniform System of Accounts. However, as discussed in the preamble, FEI has internally tracked the installation costs for meters separate from station regulators so that a separate depreciation rate for each of the two installation cost types could be applied.

When Concentric developed the depreciation rates included in the FEI 2017 Depreciation Study, the two asset categories were accounted for separately, individual depreciation rates were established for each asset category, and a weighted average depreciation rate was developed for the combined asset category.

As shown in the table below provided by Concentric Advisors, for Meter and Regulator Installations – Station Equipment the assigned curve is 20-S0 with a depreciation rate of 2.94 percent and for Meter and Regulator Installations – Meters the assigned curve is 23-SQ with a depreciation rate of 8.13 percent The weighted average of the two separate rates is 7.45 percent, which is the amount included in the Depreciation Study included in this Application.

FORTISBC ENERGY INC.

TABLE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017 RELATED TO THE RETURN OF ORIGINAL COST OF INVESTMENT

ACCOUNT	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2017	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITI REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DISTRIBUTION PLANT								
474.00A	Meter and Regulator Installations - Station Equipment	20-S0		24,885,593	17,678,848	7,206,745	732,575	2.94	7.8
474.00B	Meter and Regulator Installations - Meters	23-SQ		163,501,746	64,818,008	98,683,738	13,298,935	8.13	10.8
474.00	**METER/REGULATOR INSTALLATIONS**	**		**188,387,340**	**82,496,856**	**105,890,484**	**14,031,510**	**7.45**	**

While FEI has not applied individual depreciation rates for each of these similar asset categories, the application of a weighted average method provides a greater level of detail compared to the prior method by considering the difference in retirement profile of each asset class. Additionally, the use of a weighted average method continues to allow for the efficient administration of group depreciation. There would be no significant impact on the overall total depreciation expense if the installation costs for older gas meters and the installation costs for station regulators were grouped in separate accounts and subject to their own depreciation rates. This is because no future additions are expected to be recorded to each of these asset categories.

112.2 Please calculate the impact on depreciation expense if older gas meters and station regulator assets were grouped in separate accounts. Please also provide the resulting recommended curves and depreciation rates.

Response:

Please refer to the response to BCUC IR 1.112.1.

113.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.1.6, p. D-10; Exhibit B-1-1, Appendix D2, FEI Depreciation Study

Account 483-10– Computer Hardware

On page D-10 of the Application, FBC states the following:

> 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.

113.1 Please provide the proportion of Computer Hardware that are mobile devices compared to non-mobile devices for each of the past five years.

Response:

The proportion of Computer Hardware that are mobile devices compared to non-mobile devices for each of the past five years is outlined in the table below. Mobile devices include laptop computers and cellular phones and non-mobile devices include desktop computers and physical servers.

FEI/FBC Ratio of Mobile to Non-Mobile Devices for the period 2015-2019 (Actuals)

Computer Hardware Type	2015	2016	2017	2018	2019 (YTD)
Mobile Devices	70%	92%	91%	85%	96%
Non-Mobile Devices	30%	8%	9%	15%	4%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

113.2 Please provide a forecast of the proportion of Computer Hardware that will be mobile devices compared to non-mobile devices for each of the years of the proposed MRP term.

Response:

During the proposed MRP term, FEI and FBC are expecting the proportion of Computer Hardware capital expenditures, between mobile and non-mobile devices, to remain consistent with the recent years. Mobile devices are expected to be in the range of 92-95 percent and non-mobile devices in the 5-8 percent range.

114.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 6-31

Account 46300 – Measuring and Regulating Structures

On page 6-31 of the FEI Depreciation Study, Concentric provides the Iowa 38-S2 curve as best fit for this account.

114.1 Please explain why there appears to be several breaks in the data, and why the data visually appears closer to a step-function rather than a curve.

Response:

The following response has been prepared by Concentric.

As indicated on page 6-29 of the FEI 2017 Depreciation Study, the breaks in the data appear to occur at ages 19.5, 27.5, and 38.5. This is because the value of the investment exposed to retirement significantly drops at each of these ages. This is common in structures accounts where buildings are often constructed and put into service in a single year, causing steps in the age of investment. It is noted that the Observed Life Table is a graph of the actual surviving ratios and is not intended to be a smoothed curve. The depreciation analyst, as part of the curve fitting procedure, fits a smoothed Iowa curve to the historic Observed Life Table.

114.2 Please explain in detail the rationale for the Iowa 38-S2 curve recommendation made by Concentric.

Response:

The following response has been prepared by Concentric.

This account contains measuring and regulating buildings located on the British Columbia Mainland and on Vancouver Island. The buildings are similar in design and function to the buildings in Account 462-00 – Transmission Compressor Structures. Consequently, the life of this account should be similar.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1956 through 2017, and the retirement experience over the period of 1968 through 2017. Over this 49-year period, this account has experienced $0.76 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-29 and 6-30 of the FEI 2017 depreciation study. The original survivor curve, as plotted on page 6-

31, shows a steady rate of retirement throughout the early life of this account indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 38-S2 curve which provides a good fit to the historical data with a residual measure of 0.6743. Comments from the operations and management group suggested that life of this account should remain stable. As such, the currently approved Iowa 38-S2 curve is recommended for this account.

115.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 6-34

Account 46400 – Other Structures

On page 6-34 of the FEI Depreciation Study, Concentric recommends the Iowa 30-R4 curve as the best fit for this account and provides actuals data that show there are over 96 percent of assets still surviving at the age 44.5 years.

115.1 Please explain in detail the rationale for the Iowa 30-R4 curve recommendation made by Concentric, given the percentage still surviving at the age of 44.5 years. Was a longer service life considered? Why or why not?

Response:

The following response has been prepared by Concentric.

The retirement rate analysis for Account 464-00 results in a stub curve, which is defined as "survivor curves for which the data end before the curve reaches 0 percent surviving".[146] While more complete stub curves can be fitted with a high degree of accuracy, Iowa curves have not proven to be reliable until the percent retired exceeds 30 percent.[147] Account 464-00 has only experienced $38 thousand of retirement activity, resulting in approximately 97 percent still surviving at the oldest vintage. It is expected that the Residual Measure would not be accurate at this stage as more retirement history is needed before the retirement rate analysis for this account is considered relevant. Further, the majority of the investment in this account, $6.3M of the $6.8M total investment, has been installed since the year 2000. This large increase of investment has not had the chance to survive beyond the estimated average service life. This has the effect of making the retirement rate analysis even less reliable for Account 464-00.

Based on the above, Concentric did not place any material weight on the curve fitting procedure for this account. Instead, Concentric relied on industry knowledge, discussions with FEI management, and peer comparisons to select the Iowa 30-R4.

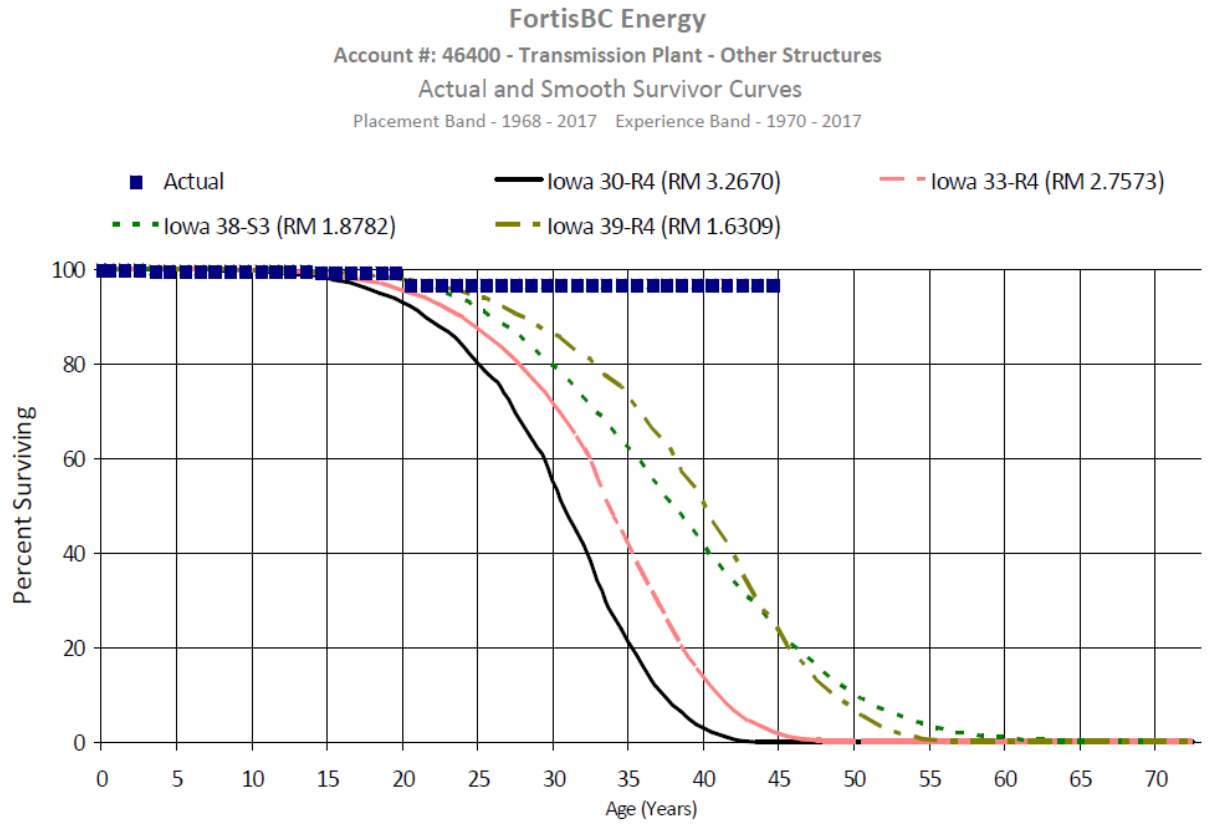
115.2 Please provide the residual measures for any other curves considered for this account. For each of the curves with a residual measure lower than 3.267 (i.e. the residual measure of the Iowa 30-R4 curve), please explain why the curve was not recommended.

[146] Wolf, Frank K and Fitch, W. Chester; Depreciation System; Iowa State University Press; 1994; Page 48.
[147] Ibid page 49.

Response:

The following response has been prepared by Concentric.

In the table below are provided the residual measures for three additional curves (Iowa 38-S3, 39-R4 and 33-R4) for account 464-00 – Other Structures, however the residual measure was not considered in the recommendation for this account.



116.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 6-50

Account 46720 – Telemetry Equipment

On page 6-50 of the FEI Depreciation Study, Concentric recommends the Iowa 10-L1.5 curve as best fit for this account and provides actuals data that show there are over 77% of assets still surviving at the age 10.5 years.

116.1 Please explain in detail the rationale for Concentric's recommendation of the Iowa 10-L1.5 curve, given the percentage still surviving at the age of 10.5 years. Was a longer service life considered? Why or why not?

Response:

FortisBC consulted with Concentric to provide the following response.

This account contains the control room and SCADA equipment in their entirety, including software and hardware. The control room was completely rebuilt in the year 2010, and was undergoing a complete rebuild again at the time of the FEI 2017 Depreciation Study. Control room rebuilds are based on industry regulations and standards, which require a high level of information security. This account is very susceptible to technological change, which may have a life shortening impact.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1968 through 2017, and the retirement experience over the period of 1973 through 2017. Over this 44-year period, this account has experienced $5.4 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-48 and 6-49 of Appendix D2-1. The original survivor curve, as plotted on page 6-50, shows a steady rate of retirement throughout the early life of this account indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 8-L1 which provides a poor fit to the historical data with a residual measure of 2.4338. Comments from the operations and management group suggested that the life of this account should remain stable. There have been major rebuilds of the assets in this account approximately every ten years in recent history. Operations and management staff indicate that this cycle is expected to continue in the future. As such, Concentric recommends the Iowa 10-L1.5 with a residual measure of 2.1162 based on comments from operations and management staff, along with industry knowledge.

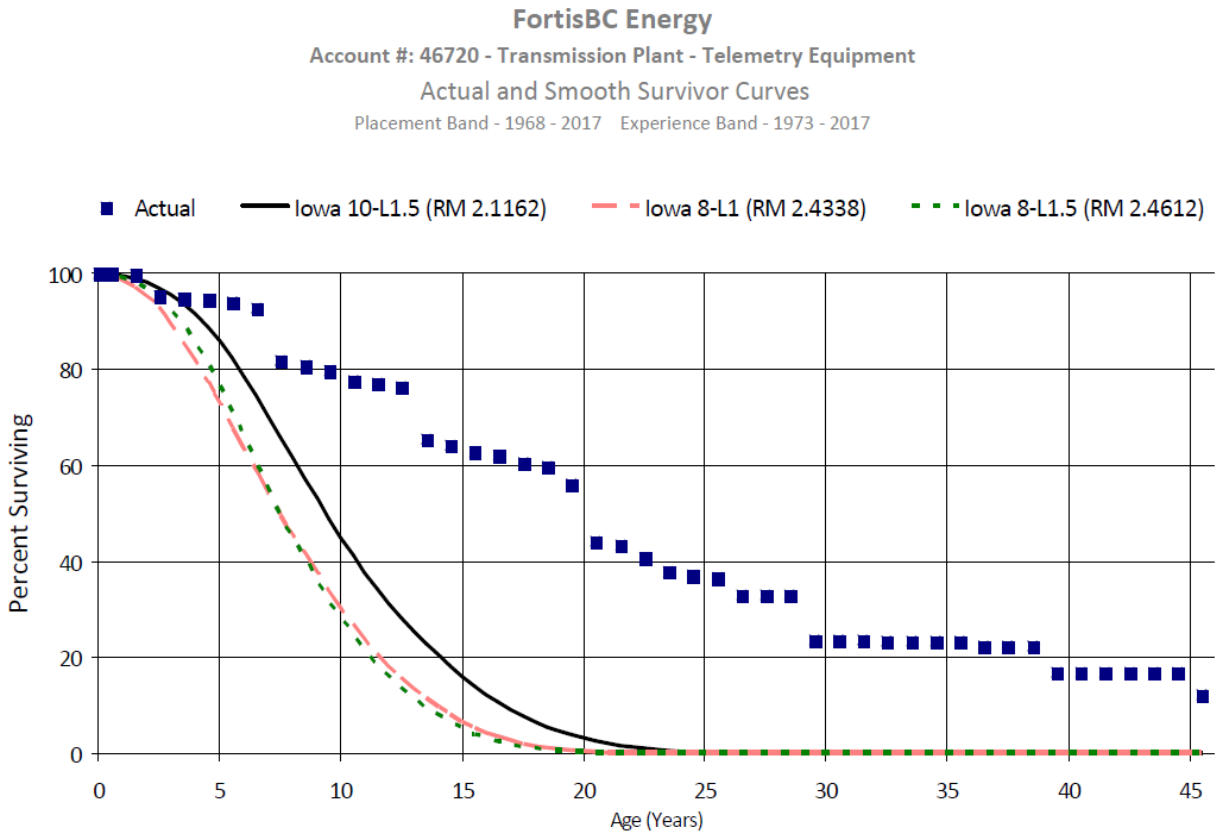
116.2 Please provide the residual measures for any other curves considered for this account. For each of the curves with a residual measure lower than 2.1162 (i.e.

the residual measure of the Iowa 10-L1.5 curve), please explain why the curve was not recommended.

Response:

The following response has been prepared by Concentric.

Shown in the table below are two additional curves (Iowa 8-L1 and 8-L1.5), both of which have a residual measure higher than 2.1162, that Concentric considered before recommending the Iowa 10-L1.5 curve. There were no curves with a residual measure lower than 2.1162.



117.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 6-78

Account 47720 – Telemetry

On page 6-50 of the FEI Depreciation Study, Concentric recommends the Iowa 20-R3 curve as best fit for this account and provides actuals data that show there are over 77% of assets still surviving at the age 20.5 years, and over 30% of assets surviving at age 58.5 years.

117.1 Please explain in detail the rationale for Concentric's recommendation of the Iowa 20-R3 curve, given the percentage still surviving at the age of 20.5 years.

Response:

The following response has been prepared by Concentric.

This account contains sensors and devices that allow data to leave a gate station site. The majority of the investment in this account is in alarm systems and data collection. These assets are primarily on the regulating system assets and the city gate systems. At this time, there are new telemetry systems being installed as needed in this account. These telemetry assets make it easier and less expensive to do upgrades as needed. Because this account has both buildings, with long lives, and technology assets, which are short lived, the average service life is expected to have a low-moded curve.

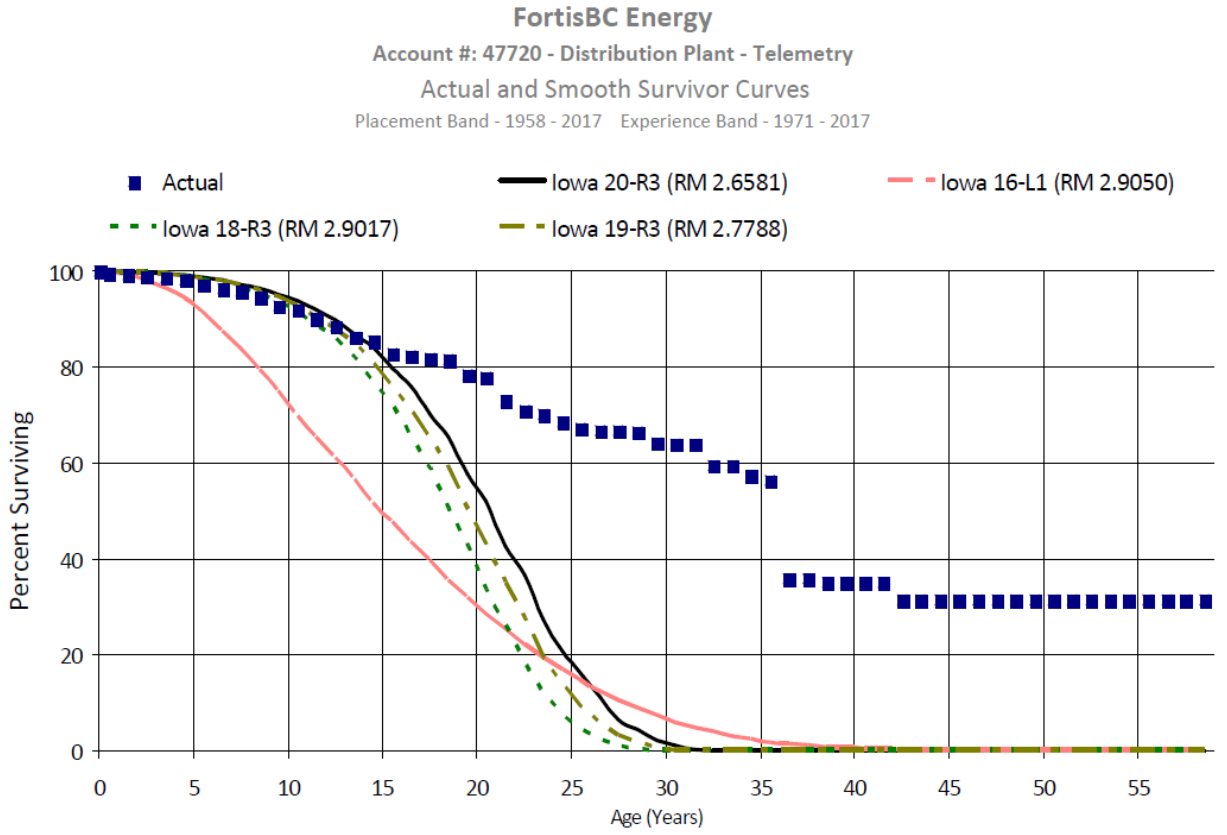
The retirement rate analysis prepared in this study reviewed the plant installed over the period 1958 through 2017, and the retirement experience over the period of 1971 through 2017. Over this 46-year period, this account has experienced $1.7 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-76 and 6-77 of Appendix D2-1. The original survivor curve, as plotted on page 6-78, shows a steady rate of retirement throughout the early life of this account indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 16-L1 which provides a poor fit to the historical data with a residual measure of 2.9050. Comments from operations and management suggest that there may be service life decreases in some assets in the future, however given the mix of assets in this account, it is not prudent to reduce the average service life at this time. As such, Concentric recommends the Iowa 20-R3 curve, with a residual measure of 2.6581, based on comments from operations and management staff, along with industry knowledge.

117.2 Please provide the residual measures for any other curves considered for this account. For each of the curves with a residual measure lower than 2.6581 (i.e. the residual measure of the Iowa 20-R3 curve), please explain why the curve was not recommended.

Response:

The following response has been prepared by Concentric.

Shown in the table below are three additional curves (Iowa 16-L1, 18-R3 and 19-R3), all of them having a residual measure higher than 2.6581, that Concentric considered before recommending the Iowa 20-R3 curve.



Please refer to response to BCUC IR 1.117.1 for the reasons of choosing Iowa 20-R3.

118.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.1.2, p. D-8

Services (473-00)

On page D-8 of the Application, FortisBC states the following:

> The average age of retirement from 2014 through 2017 was 20.2 years, as compared to an average age of retirement 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.

118.1 Please explain why a recommended life of 47 years is used, when Concentric states that the life of these lines is expected to be on the longer end of peer utilities (which range from 40 through 62 years).

Response:

The following response has been prepared by Concentric.

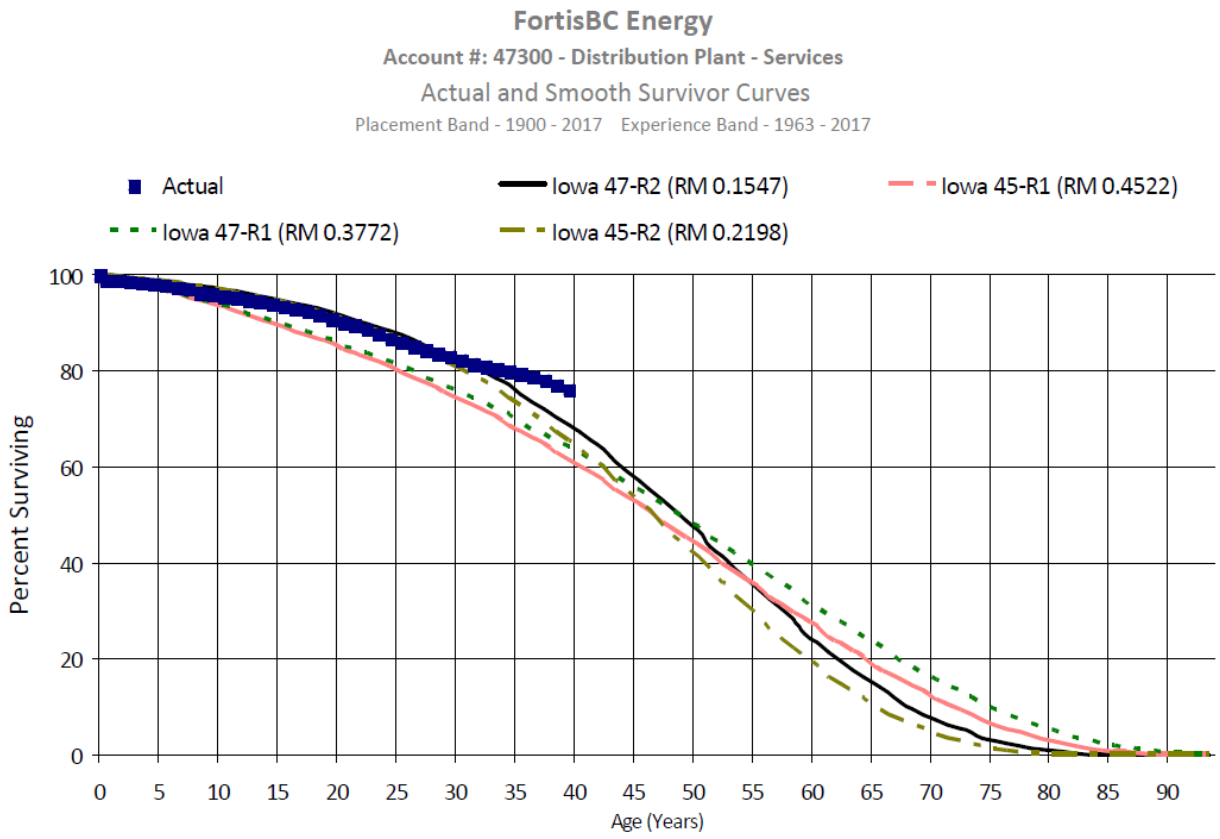
While the average service life among peer utilities is between 40 to 62 years and FEI Services are expected to be on the longer end of peer utilities, the retirements in this account are primarily driven from factors outside the normal wear and tear of the asset. Main reasons for the early retirements of Services before being able to reach the estimated average service life are the result of infrastructure changes, third party requests and inactive services. Iowa 47-R2 gives a very good fit to the historical data through age 32.5. The Iowa 47-R2 falls exactly on top of the actual historical data. While peer data was reviewed for this account, the goodness of fit was more relevant to the choice of 47-R2. The 47 year life was determined as a best fit for account 473-00 Services based on actual retirement history, accumulated losses as a result of the early asset retirement, peer analysis and professional judgment. The currently approved life for this account is an Iowa 45-R1. The recommended 47-R2 extends the life of this account by two years, bringing it closer in line with peer utilities.

118.2 Please provide the residual measures for any other curves with average service lives longer than 47 years that were considered for this account. For each of the curves with a residual measure lower than 0.1547 (i.e. the residual measure of the Iowa 47-R2 curve), please explain why the curve was not recommended.

Response:

The following response has been prepared by Concentric.

Shown in the table below are three additional curves (Iowa 45-R1, 45-R2 and 47-R1), all of them having a residual measure higher than 0.1547, that Concentric had considered prior to recommending the Iowa 47-R2 curve.



Please refer to response to BCUC IR 1.118.1 for the reasons of choosing Iowa 47-R2.

119.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study p. 3-3

Account 331.00 – Generation Plant – Structures and Improvements

On page 3-3 of the FBC Depreciation Study, Concentric states the following:

> Because of the relatively fixed components, this account has not experienced a substantial amount of retirement but recent upgrades and retirements reinforce a shorter life in line with peers in the same industry…
>
> …The 60-S1.5 considers interim retirements that have historically occurred at ages 25 to 35, thus shortening the estimate of average life.

119.1 Please explain why these recent upgrades and retirements were needed. If these upgrades had not occurred, would Concentric have recommended the previously approved 68-S2.5 curve rather than the recommended 60-S1.5 curve? Please explain why or why not.

Response:

The recent upgrades and retirements in Account 331.00 – Generation Plant – Structures and Improvements were required in compliance with BC Building and Fire Code regulations. The interim retirement of assets that occurred between the ages of 25 to 35 years can primarily be attributed to FBC removing and replacing infrastructure that did not meet provincially regulated BC Building and Fire Code. The infrastructure that was removed and replaced in accordance with these codes included fire panels, powerhouse doors and windows, generator deluge system and a forebay access platform.

The following portion of the response has been prepared by Concentric.

Concentric would not have changed their life recommendation. The indications from the recent upgrades and retirements were one input into Concentric's parameter selection process. As stated on page 3-3 and 3-4 of the FBC 2017 Depreciation Study, historical data was analyzed by the retirement rate method and discussions were held with operational and management staff. In addition, as depicted on page 6-5 in Appendix D2-2, an Iowa 60-S1.5 has a better fitting residual measure ("RM") of 1.0314 versus the currently approved curve, an Iowa 68-S2.5 with a RM of 1.2545. The 60-S1.5 considers interim retirements that have historically occurred at ages 25 to 35, thus shortening the estimate of average life.

119.2 Please explain the causes of the interim retirements that have historically occurred at ages 25 to 35. Why are the lives for these assets shorter? Please discuss.

Response:

Please refer to the response to BCUC IR 1.119.1.

120.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 3-6

Account 334.00 – Generation Plant – Accessory Electrical Equipment

On page 3-6 of the FBC Depreciation Study, Concentric states the following:

> The retirement rate analysis has indicated that the existing Iowa 50-R1.5 curve provides a good fit related to historical retirements (page 6-14), however it is anticipated that future retirements will most likely not follow the same trends as the past. Discussions with engineering and operations staff provided the expectation that newer digital equipment would not achieve the service lives as witnessed in the past. Operations personnel indicated that the control equipment included in this account has been mostly replaced with digital technology. Newer digital equipment provides for better condition assessments of the assets being protected, however, the technological nature and reliance on vendor support for the technology included in these assets will cause retirement at an earlier age than previously experience with the older generation mechanical protection equipment. Concentric considers 40-R2.5 curve as more representative of the rate of consumption of service value of these assets.

120.1 Please provide the proportion of equipment in this account that has been replaced with digital technology and discuss when FBC plans to have 100 percent of the equipment in this account as digital equipment.

Response:

FBC operates 15 generating units at its four generation plants and the protection and control of 13 units (87 percent) have been replaced with digital equipment. By the end of 2020, it is expected that all 15 generating units' protection and control systems will be fitted with digital equipment. However, FBC expects that non-digital accessory electrical equipment will continue to be included in this account as this equipment is utilized in the event of an equipment or communication failure.

120.2 Please provide a copy of the interview notes with FBC staff and explain how Concentric used these comments to recommend the use of the Iowa 40-R2.5 curve, rather than using the previously approved 50-R1.5 curve.

Response:

The following response has been prepared by Concentric.

Provided below are the interview notes for account 334.00 – Generation Plant – Accessory Electrical Equipment:

> **Account 334.00 - Accessory electrical equipment**
>
> The control equipment that makes up part of this account has been mostly switched to digital technology, which although provides for better condition assessments, has a trade-off with lower service lives than older generation mechanical equipment. We are consequently evaluating whether a 50-R1.5 curve is more representative of the rate of depreciation in this account. In this case, we are not as concerned with trying to reduce the residual measure since that curve will fit the retirement of older technology which has largely been retired. A 40-year life with slightly higher mode (R2.5) would reflect the average shorter life because of the newer digital equipment.

The discussion with FBC Operations noted that newer technology is preferred to the older mechanical equipment, however it has a lower average life as a trade-off and as a result of the components in this class of equipment, the old 50-R1.5 curve was no longer representative of average service lives and instead the Iowa 40-R2.5 curve is recommended as a better fit.

120.3 Please provide the residual measure for the Iowa 50-R1.5 curve, and compare it to the residual measure of the recommended Iowa 40-R2.5 curve.

Response:

The following response has been prepared by Concentric.

The Iowa 50-R1.5 curve indicates a better mathematical fit with a Residual Measure of 0.5047 then the recommended Iowa 40-R2.5 with a Residual Measure of 1.5445. However, as stated on page 3-6 of the FBC 2017 Depreciation Study, it is anticipated that future retirements will most likely not follow the same trends as the past. Discussions with engineering and operations staff provided the expectation that newer digital equipment would not achieve the service lives as witnessed in the past. Operations personnel indicated that the control equipment included in this account has been mostly replaced with digital technology. Newer digital equipment provides for better condition assessments of the assets being protected, however, the technological nature and reliance on vendor support for the technology included in these assets will cause

retirement at an earlier age than previously experienced with the older generation mechanical protection equipment. Concentric considers 40-R2.5 curve as more representative of the rate of consumption of service value of these assets. Therefore, Concentric has provided less weighting to the Residual Measure given that the assets associated with the retirement ratios which generated the observed Residual Measure have largely been retired. Concentric recommends a change to a 40-year life which is consistent with the views of the FortisBC operations and engineering groups, and is within the range of similar accessory electrical equipment in the same peer group.

121.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 3-14

Account 390.10 – General Plant – Structures Masonry

On page 3-14 of the FBC Depreciation Study, Concentric states the following:

> A fit to observed data indicated that the currently approved Iowa 41-S3 has been replaced by a better fit curve of 35-S1 with a RM of 0.5589 (page 6-63) as compared to the previously approved Iowa 41-S3 curve which has a residual measure of 0.9805.

121.1 Please explain the cause of the increase in retirements, or decrease in average age, for this class of assets.

Response:

In 2017, FBC retired approximately $1.5 million of gross general plant structures, with original installation costs between 1975 and 2015 resulting in an average life of this investment of 21.5 years. Approximately $0.869 million of these assets were retired pursuant to BCUC Order C-2-16 granting a Certificate of Public Convenience and Necessity for the Kootenay Operations Centre which requested the Castlegar District Office be included within this project "… *The Panel determines that the public interest is best served by adding the immediate replacement of the Castlegar facilities to the requested alternative approval, referenced in these reasons as Alternative "5A")*".

The historical data included in the FBC 2017 Depreciation Study (pages 6-58 to 6-60), as compared to the historical data included in the FBC 2014 Depreciation Study (pages V-64 to V-66), indicates a substantial amount of interim retirement activity from ages 10 forward. This increased retirement activity has resulted in a recommended Iowa 35-S1.

122.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 6-34

Account 359.00 – Roads and Trails

On page 6-34 of the FBC Depreciation Study, Concentric recommends the Iowa 50-R3 curve as best fit for this account and provides actuals data that show there are over 94% of assets still surviving at the age 44.5 years, which immediately drops to 11% of assets surviving at age 45.5 years.

122.1 Please explain the cause(s) of the retirements between the above intervals.

Response:

The retirement of assets within Account 359.00 - Roads and Trails in 2003 was caused by the replacement of substations and rerouting of transmission lines between Trail and South Slocan that occurred as part of the Kootenay 230 kV System Development Project. These retirements that have occurred between the age intervals of 44.5 and 45.5 years were included in previous depreciation studies for FBC. There were no new retirements during the three years for which the FBC 2017 Depreciation Study was updated for.

122.2 Please explain the rationale for the Iowa 50-R3 curve recommendation made by Concentric, given the amount of retirements that occurred between ages 44.5 and 45.5.

Response:

The following response has been prepared by Concentric.

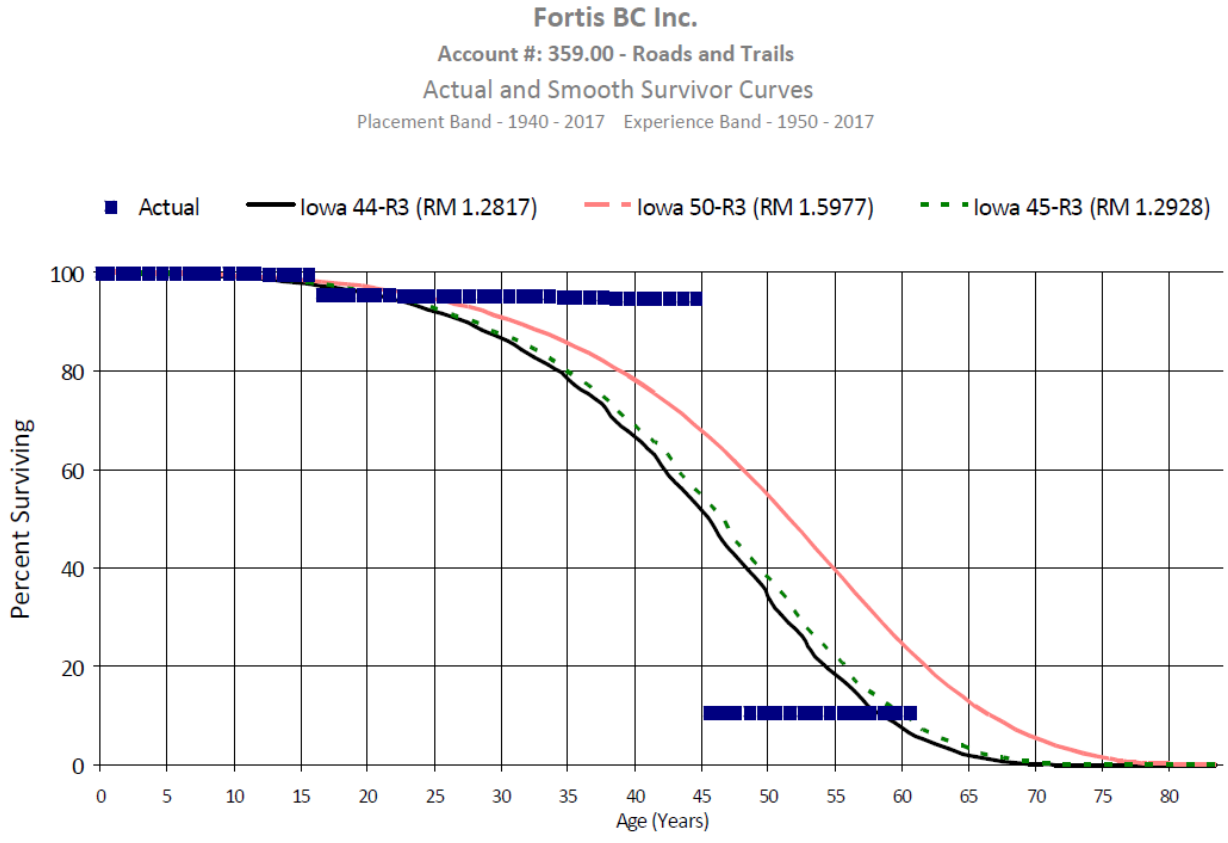
Concentric's view is that, in reference to pages 6-32 and 6-33 of the FBC Depreciation Study, although there is a retirement of $94,582 at age 44.5 years, the related exposures of $106,994 are a small component of the maximum exposures of $1,230,779 (page 6-32). The shape of the recommended Iowa 50-R3 (page 6-34) fits the larger investment ages up to age 44.5 significantly better than the previous Iowa 40-R3. As such Concentric views that the recommended Iowa 50-R3 is a more appropriate fit to the complete historical data than the Iowa 40-R3.

122.3 Please provide the residual measures Iowa curves with a 44- and 45-year average life. For each of the curves with a residual measure lower than 1.5977 (i.e. the residual measure of the Iowa 50-R3 curve), please explain why the curve was not recommended.

Response:

The following response has been prepared by Concentric.

The chart below provides the residual measures for Iowa curves with a 44 and 45 years average service life. Although both the Iowa 44-R3 and Iowa 45-R3 have lower mathematical Residual Measures than the recommended Iowa 50-R3, Concentric views that the more relevant and appropriate ages are those indicated in the response to BCUC IR 1.122.2. A Residual Measure comparison of the more significant ages from 0 to 44.5 would indicate a better fit than the Iowa 44-R3 and 45-R3.



123.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 6-55

Account 371.00 – Installations on Customers' Premises

On page 6-55 of the FBC Depreciation Study, Concentric recommends the Iowa 20-R1 curve as best fit for this account and provides actuals data that show there are over 69% of assets still surviving at the age 56.5 years.

123.1 Please explain the rationale for the Iowa 20-R1 curve recommendation made by Concentric, given the percentage still surviving at the age of 56.5 years. Please explain, in consideration of the actuals data, why Concentric considers an average life of 20 years to be reasonable.

Response:

The following response has been prepared by Concentric.

As shown on pages 6-53 and 6-54 of the FBC 2017 Depreciation Study, the bulk of retirements occurred from age 0 to age 16.5. There is one larger retirement at age 24.5. The result of this lack of retirement experience is called a life plateau. Basically, there is very little change in the historical data from age 16.5 forward. Therefore, Concentric has viewed that the historical data up to age 16.5 is more relevant and indicative for the expected life of the equipment in this account.

As this account has experienced no change in historical data since the previous study, no change was recommended and no other Iowa curves were contemplated. In addition, FBC no longer incurs capital expenditures meeting the description of this account and, as a result, ceased recording depreciation expense once these assets reached a net book value of nil. Therefore, whether a curve of 20 years or 56.5 years is utilized, there will not be an effect on depreciation expense for the term of the MRP or in future filings.

123.2 Please provide the residual measures for any other curves considered for this account. For each of the curves with a residual measure lower than 3.7966 (i.e. the residual measure of the Iowa 20-R1 curve), please explain why the curve was not recommended.

Response:

Please refer to response to BCUC IR 1.123.1.

124.0 Reference: DEPRECIATION STUDY

Exhibit B-1, Section D2.2.2, p. D-11

Net Salvage

On page D-11 of the Application, FortisBC states the following:

> 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.

124.1 Please explain in detail FEI's policies regarding removal and/or abandonment of assets, including removal and/or abandonment due to retirement and/or replacement.

Response:

FEI would generally remove assets from service due to customer requests and safety/reliability related reasons.

FEI regularly assesses and monitors the health of its transmission and distribution systems, noting factors such as the age and condition of the pipe installed, identified leaks, effectiveness of corrosion prevention and condition of coatings on the pipe. Where warranted, FEI replaces the transmission and distribution mains earlier than expected in order to maintain the integrity of the pipe.

When the opportunity arises, FEI schedules pipe replacement to coincide with municipal or road construction activities in order to minimize the costs. Customer requests to relocate distribution mains may also lead to earlier retirement than expected. Highway construction, municipality activities and private industry development may result in FEI having to retire and relocate an existing main.

Customer requests to retire services originate as a result of land development activities and specific requirements of customers as a result of existing housing and land being redeveloped with larger plots of land being subdivided and existing housing demolished to make way for multifamily housing (i.e., townhouses, condos). Other customer driven requests include those resulting from homeowners performing building modifications and landscaping activities that require the retirement of service line assets.

To expand on the comments above, FEI removes assets when they are in the way of other work being undertaken. For example, if a valve needs to be replaced because it no longer performs

satisfactorily, it will have to be removed prior to installing a new valve as it would obstruct the space required to install the new valve. If a station requires piping or equipment upgrading due to insufficient capacity, the existing piping or equipment will have to be removed prior to installing the new piping or equipment, again, because the existing piping or equipment is an obstruction. Short sections of buried pipe are often replaced due to damage which necessitates that the damaged pipe be cut out and removed prior to the replacement pipe being installed. Thus, generally, if there is a replacement of an existing asset, such as a valve, equipment or a short section of pipe, then the existing asset will need to be removed in order to allow the new asset to be installed. In each of these examples, the equipment or pipe may or may not have reached its anticipated financial service life.

FEI generally abandons long linear type assets, such as buried pipes, in place. This is often because the existing pipe must remain in service until a replacement pipe is put into service. As the replacement pipe is most likely along a new running line, i.e., at a new location, the original pipe is abandoned in place as removing it would increase the amount of work, the cost of the work and the impact on the public due to limitations placed on access and travel during construction.

The primary drivers for having to abandon long lengths of pipe are third party driven alterations and FEI's pipe renewal programs. If a third party, such as a municipality or developer, request that FEI move the pipe to a new location due to road construction, FEI will abandon the pipe and will not take it out to be relocated or reinstalled in the new location. Moving the existing pipe to a new location is rarely practical as to maintain supply to customers the existing pipe has to remain in service while a new pipe is installed elsewhere. When the new pipe is put into service, the existing pipe is abandoned in place. If FEI was to remove all of the original pipe, the cost to the third party would increase significantly. FEI's pipe renewal programs consist of replacing distribution mains that have a higher risk to public safety and reliable service and replacing transmission pipelines due to nearby population growth to ensure public safety. Generally when undertaking a pipe renewal project, FEI will abandon the existing pipe in place; however, with some of the recent transmission pipeline upgrades, FEI has had to be remove the existing transmission pipeline in order to create an installation location for the replacement pipeline.

All assets that are physically removed or abandoned are also retired within the capital asset subledger.

124.1.1 As part of the above response, please explain if FEI removes or abandons pipelines when the assets reach the end of its service life.

Response:

FEI does not determine or even consider the need for replacement of pipeline based on the remaining financial lives of an asset (i.e., the period for recovery of capital through depreciation expense). As discussed in response to BCUC IR 1.124.1, the need for replacement depends on factors such as third-party relocation requests, system alterations to meet operational needs, and integrity concerns. For example, if a pipeline is in good condition, operational and safe for the public, it will continue to remain in service beyond its estimated service life.

When a short section of pipeline no longer meets the needs of the company, such as it can no longer serve its intended purpose or it is not cost effective or easy to repair, it will likely be removed and replaced. If it is a long section of a pipeline, it will likely be abandoned in place and, depending on the circumstances, it may or may not be replaced.

124.1.2 Please explain in detail the types of activities that are included in removal costs.

Response:

The type of activities that are included in removal costs are those required to dispose of and remove the existing asset from the construction site. This may include expenditures for labour, material, and contract services required to demolish, dismantle, tear down, dispose of or otherwise remove the plant from service. More specific examples of these expenditures may include, but are not limited to, costs to haul away and dispose of assets that have been removed, remediation costs to make the retired asset and equipment safe and to comply with any regulations (i.e., environment, municipal) if the asset is left in the ground, excavation costs, and costs to cut abandoned pipe into shorter segments and seal the segments.

124.2 Please explain in detail what is driving the increases in FEI's actual cost of asset removal activities.

Response:

The increases in FEI's actual cost of asset removal have been due to higher costs associated with replacement of larger diameter valves, pit-type stations, and longer sections of transmission pipeline. The higher costs are due to replacing large diameter valves and

replacement of pit type stations, which have occurred in urban areas where work space is limited and work restrictions exist (from municipalities for example). The sections of transmission pipeline have had to be removed, rather than abandoned, in order to allow the installation of the replacement pipe. The need for gas system retirements or replacement is primarily impacted by factors such as third party relocation requests, system alterations for operating benefits, and integrity concerns. This type of work has become necessary to ensure the integrity and reliability of the systems and the safety of the public.

As a result of these factors, it is also necessary to increase the net salvage provision to allow for recovery of currently and future removal activities. The main factors for the increase in the net salvage provision are the continuous need for ongoing retirements or replacement of the gas system, the continual increase in actual removal costs, inflation and net salvage studies indicating that higher net salvage percentages are required in order to offset the cost incurred due to an increase in asset removal activities as compared to actual retirements.

124.2.1 As part of the above response, please explain, in consideration of FEI's policies regarding abandonment versus removal, why the provision for net salvage is proposed to increase.

Response:

As the lower cost option, FEI would normally abandon in place transmission pipeline and distribution services and mains. Even though these assets are not physically taken out of the ground, in order to abandon them, various activities are involved, such as excavation to access the pipe, segmenting longer pipe sections into shorter segments, sealing the pipe ends of the pipe segments and rehabilitation of the excavation and ground surface. While these activities may not be as costly as physically removing the pipe, because the practice is applied to larger pipeline segments, the costs can still be significant.

Further, in some cases FEI has been required to physically remove the pipe, which is significantly more costly.

Please refer to the responses to BCUC IRs 1.124.1 through 1.124.2.

124.3 Please provide as an example the journal entries and financial/regulatory account impacts for the treatment/recording of actual net salvage costs. Please include supporting descriptions for the journal entries.

Response:

The net salvage provision liability account represents the accumulated net salvage provision collected through depreciation/amortization less actual costs of removal and any salvage proceeds. FEI records the net salvage provision as a rate base deferral account liability as directed in BCUC Order G-44-12 and FBC records the same net salvage provision as a credit to accumulated depreciation as directed in BCUC Order G-202-15. While this is a different presentation for regulatory accounting purposes, both entities record the net salvage provision liability as a credit to rate base with the same impact on revenue requirements. For USGAAP external financial reporting purposes, both FEI and FBC present net salvage provision on the balance sheet as a long-term regulatory liability.

When there is a removal cost incurred, it is recorded as a debit to the net salvage provision and when net salvage is collected in depreciation/amortization expense, it is recorded as a credit to the net salvage provision liability. Any proceeds received from an asset disposition are also recorded in the net salvage provision liability as a credit.

Examples of journal entries associated with net salvage, with supporting descriptions underneath the journal entries, are as follows:

DR	Depreciation/Amortization expense	$xxx
CR	Net salvage provision liability	$xxx

To record the net salvage collected in customer rates through depreciation/amortization expense.

DR	Net salvage provision liability	$xxx
CR	Accounts Payable/Labour/Cash	$xxx

To record an invoice received from a contract who performed activity related to an asset retirement activity or labour. Costs of removal, either incurred internally or through an external contractor, are recorded against the Net salvage provision liability

DR	Cash	$xxx	
CR	Net salvage provision liability		$xxx

To record proceeds received from asset disposition/scrapping/sale

124.4 Please explain if FEI and FBC recognize Asset Retirement Obligations (AROs) for financial statement purposes related to their regulated assets. If no, please explain why not.

Response:

Currently, only FBC has recognized an Asset Retirement Obligation (ARO) pursuant to Accounting Standards Codification (ASC) 410 Asset Retirement and Environmental Obligations in its external financial statements prepared under US GAAP which relate to regulated assets. The ARO has been recognized and estimated at approximately $2 million as of December 31, 2018. It relates specifically to the legal obligation associated with the removal of Polychlorinated Biphenyls (PCBs) in station equipment and distribution equipment as determined under Environment Canada Polychlorinated Biphenyls Regulations. This ARO will be drawn down as certain of the expenditures relating to the PCB Environmental Compliance project, which is described under Section C3.4.1.2.4, Distribution Sustainment Capital, of the Application, are incurred.

There are no other material AROs to be recognized by FEI or FBC under US GAAP at this time. It is probable that FortisBC will be required to incur some cost to decommission major portions of infrastructure at the end of their useful lives. However, these assets are assumed to operate in perpetuity and since the date upon which they will be taken out of service is generally not determinable, the fair value of the obligation cannot be reasonably estimated.

FEI and FBC's ARO policy is disclosed in the annual audited financial statements prepared under USGAAP as follows:

> The Corporation recognizes the fair value of a future ARO as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The fair value of the ARO is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the ARO is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are recognized as a regulatory asset using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The Corporation has AROs for which the obligations cannot be reasonably estimated at this time. These AROs are primarily associated with the Corporation's hydroelectric generating facilities and assets associated with interconnection facilities. While each of the foregoing will have legal asset retirement obligations (i.e. land and environmental remediation and/or removal of assets), the final date of removal of the related assets and the costs to do so cannot be reasonably determined at this time. There is a reasonable expectation that asset retirement costs would be recoverable through future rates.

124.4.1 As part of the above response, please describe FEI and FBC's policy regarding AROs.

Response:

Please refer to the response to BCUC IR 1.124.4.

124.5 Please explain how the recognition, or lack of recognition, of AROs for financial statement purposes is consistent with FEI and FBC's calculation and recording of net salvage provisions.

Response:

Per US GAAP, AROs are required to be recognized when an obligation exists to retire a tangible long-lived asset as a result of an existing or enacted law or as a result of an expectation

of performance under the principle of promissory estoppel. The triggering event for recognizing an ARO is when a future legal liability is identified and can be reasonably estimated.

In addition to AROs, net salvage provisions can be recognized for certain assets such that at the end of its useful life FortisBC has fully recovered from customers through rates not only the original cost of the asset through annual depreciation rates, but also any expected costs of removing those assets. These estimated future removal costs are recovered through revenue requirements as a component of depreciation/amortization rates referred to as net salvage (debit net salvage in depreciation and a credit to the net salvage provision). Unlike AROs, removal costs that form part of the net salvage provision do not generally arise because of a legal obligation but are rather triggered by the collection of amounts from today's customers (that are benefiting from the use of the assets) to be used for costs of removal when those assets are removed from service.

AROs and net salvage costs are similar in the sense that they are based on a premise that asset ownership includes the responsibility for the asset's ultimate retirement or removal. In addition, even though the ARO and net salvage arise as a result of different triggering events, the costs represent obligations of FortisBC and are treated as long-term liabilities for external financial statement purposes under US GAAP.

124.5.1 What is the relationship between AROs and net salvage, if any? Please explain.

Response:

Please refer to the response to BCUC IR 1.124.5.

125.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 3-3

Net Salvage

On page 3-3 of the FBC Depreciation Study, Concentric states the following:

> Given that there has been only one previous provision for net salvage in the 2014 study, the complete integration of net salvage into the rates would cause a significant impact on the rates charged to customers. Therefore, Concentric is recommending the continuation of the gradual transition to the required amounts of negative salvage percentages.

125.1 Please provide the immediate impact to rates if FBC were to completely integrate the required amounts of negative salvage percentages.

Response:

While the statement in the preamble suggests that FBC is in a transition plan to a particular net salvage percentage that is higher than what is included in the FBC 2017 Depreciation Study, that is not the case. Rather, FBC intends to perform depreciation studies with its external consultant every three to five years, evaluate the analysis and recommend an appropriate net salvage percentage at that time. That evaluation and recommendation is based on the statistical analysis of data, actual retirement activity, industry trends and professional judgment. Each depreciation study could result in the net salvage being revised upwards or downwards depending on these factors.

Similarly, Concentric has indicated that the recommendations considered the results of the study, in combination with professional judgement which considered such factors as the limited amount of historic data, the influence of large changes on the end customer rates, a comparison to peers and the views of company management. At the next study Concentric and FBC will again evaluate whether a revision to the expected net salvage is appropriate.

Given that there is no particular net salvage rate that FBC expects to transition to in the future, there is no immediate impact to rates to be calculated.

125.2 When will the transition of required negative salvage be complete?

Response:

Please refer to the response to BCUC IR 1.125.1.

125.3 Please explain if the gradual transition will cause further increases to net salvage rates in future studies due to the delay in recovering full amounts of negative salvage during the current transition periods.

Response:

Please refer to the responses to BCUC IRs 1.125.1.

125.4 Please explain in detail how Concentric determined the appropriate transition period. What does Concentric consider a large change, and what are the criteria used to determine this?

Response:

The following response has been prepared by Conentric:

Concentric's view of a net salvage transitional period has been and will be based, for each successive depreciation study, on the appropriate considerations at the time of each study, rather than on any pre-determined transitional plan. Concentric views that the magnitude of change of net salvage parameters in future studies will be entirely based on the facts and circumstances at that time.

125.5 For those accounts where net salvage percentages have changed, please indicate how much of the change is due to the gradual integration of previously approved amounts, and how much of the change is due to other factors.

Response:

As described in the response to BCUC IR 1.125.1, there is no component of the change in the proposed net salvage percentages derived from the FBC 2017 Depreciation Study that is considered a gradual integration or transition. Rather the changes in net salvage rates are determined based on a combination of factors, including statistical analysis of data, actual retirement activity, industry trends and professional judgment and it is not possible to reasonably isolate the causation to each factor.

125.5.1 Please explain in detail the factors causing the change for each account that is not due to the gradual integration of previously approved amounts.

Response:

The overall increase in net salvage is primarily due to actual cost of removal activity for the past three years, peer analysis amongst other electric utilities as well the professional judgment of Concentric and FBC operations and management staff expectations. In the FBC 2017 Depreciation Study net salvage is proposed for two new accounts 390.10 Structures – Masonry and 390.20 - Operations buildings as a result of actual cost of removal activity and the expectancy that this trend continues when a building is retired and demolished.

126.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2

Net Salvage increases

FortisBC provides specific salvage recommendations for both FEI and FBC for each of the account groups, several of which have changed from the previous study.

126.1 Please confirm, or explain otherwise, whether a separate, more detailed net salvage study was prepared other than the one included in Exhibit B-1-1. If confirmed, please provide a copy, and explain how the study was used to provide the recommended rates. If not confirmed, please explain how the salvage recommendations were arrived at.

Response:

The following response has been prepared by Concentric.

Not confirmed. There was only one net salvage study prepared by Concentric Advisors which is already included in Appendix D2-1 - FEI 2017 Depreciation Study and D2-2 - FBC 2017 Depreciation Study. The Concentric recommendations considered the results of the study, in combination with professional judgement which considered such factors as the limited amount of historic data, a comparison to peers and the views of company management.

127.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-9

Net Salvage Change for Account 473.00 - Services

On page 3-9 of the FEI Depreciation Study, Concentric states the following:

> This study recommends making a change to the net salvage rate, from negative 60 percent to negative 70 percent. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last eight three-year rolling bands are both more negative than negative 100 percent, as are the last seven five-year rolling bands. The historical net salvage rate is negative 119 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 100 percent at this time, however given the concept of gradualism Concentric is recommending moving the net salvage to a negative 70 percent.

127.1 Please provide a detailed explanation of the factors that resulted in increases in the historical net salvage rate.

Response:

The Net salvage rate is evaluated periodically with every depreciation study and takes into account factors such as: actual cost of removal, retirements profile, company outlook and professional judgement.

Since the FEI 2009 Depreciation Study, the net salvage percentage has increased from negative 50 to negative 60 (FEI 2014 Depreciation Study), to negative 70 (proposed in the FEI 2017 Depreciation study). The net salvage rate has increased from 1.07 percent (2009) to 1.61 percent (2014) to 2.09 percent (proposed in the FEI 2017 Depreciation Study). The main factor contributing to the increase in the net salvage rate is that the actual cost of removal continues to be high as a result of actual service retirements. FEI expects this trend to remain consistent in the next few years.

127.2 Please explain how Concentric calculated the recommended rate of 70 percent and provide the calculation.

Response:

The following response has been prepared by Concentric.

No specific calculation was performed. As stated on page 3-9 of the FEI 2017 Depreciation Study and quoted above, the Summary of Book Salvage, shown on page 7-15, indicates progressive increases in the historical net salvage. With the total historical net salvage being negative 119 percent, Concentric views that negative 100 percent would be a reasonable expectation. However Concentric has recommended a more conservative move to a negative 70 percent until future studies continue to indicate a need for a larger increase.

127.3 Did Concentric complete a peer comparison of salvage rates for this account? If so, please provide this comparison. If no, please explain why not.

Response:

The following response has been prepared by Concentric.

Concentric completed a peer comparison of the net salvage percentage used among other utilities for the accounts shown in the table below, which includes account 473.00 - Services.

Net salvage	PNG	AtcoGas	AltaGas	SaskEnerg	CentraGas	Enbridge
MANUFACTURING PLANT						
432 Structures						
433 Equipment						
434 Holders						
436 Compressor Equipment						
437 Measuring and Regulating Equipment						
LNG PLANT						
442 Structures						
442.01 Structures - Mt. Hayes						
443 Equipment						
443.05 Equipment - Mt. Hayes						
448.1 Piping						
448.2 Pre-Treatment						
448.3 Liquefaction Equipment						
448.4 Send Out Equipment						
448.5 Substation and Electrical						
448.6 Control Room						
449 Other Equipment						
449.01 Other Equipment - Mt. Hayes						
TRANSMISSION PLANT						
462 Compressor Structures	-3					
463 Measuring and Regulating Structures	-15		0		0	
464 Other Structures						
465 Transmission Pipeline	-20		-10		0	
465.11 Intermediate Pipe - Whistler						
465.3 Mains - Mt. Hayes						
466 Compressor Equipment	-7					
467 Measuring and Regulating Equipment - Mt. Hayes						
467.1 Measuring and Regulating Equipment	-7		-35		0	
467.2 Telemetry Equipment						
467.31 Measuring and Regulating Equipment - Whistler						
468 Communications Equipment	0					
DISTRIBUTION PLANT						
472 Structures	-10	-40	0	-15		-20
473 Services	-60	-100	-30	-60		-45
474 Meter/Regulator Installations	-20	-30	0	0		
474.02 New Meter Installations		-20				
475 Systems - Mains	-25	-60	-10	-20		-85 - -125
476 NGV Fuel Equipment						0
477.1 Measuring and Regulating						
477.2 Telemetry						
478.1 Meters	1	0	0	0		5
478.2 Instruments						
BIO GAS						
472.2 Structures and Improvements						
474.1 Meters/Regulator Installations						
475.1 Mains - Municipal Land						
477.4 Measuring and Regulating						
478.3 Meters						
418.1 Purification Overhauls						
418.2 Purification Upgrader						
NG FOR TRANSPORTATION						
476.1 CNG Disp Equipment						
476.2 LNG Disp Equipment						
476.3 CNG Foundation						
476.4 LNG Foundation						
476.5 LNG Pumps						
476.6 CNG Dehydrator						
GENERAL PLANT						
482.1 Stuctures (Frame)	0	0	0			
482.2 Structures (Masonry)	0	0	0			
483.1 Computer Hardware	0	0	0			
483.2 Computer Software (12.5%)	0	0	0			
483.25 RNG Computer Software (20%)						
483.3 Office Equipment	0	0	0			
483.4 Furniture	0	0	0			
484 Vehicles	15	10	25		10	
485.1 Heavy Work Equipment	10	25	20		20	25
485.2 Heavy Mobile Equipment						
486 Small Tools/Equipment		0	0			
487.2 NGV Cyinders						
488.1 Telephone Equipment		0				
488.2 Radio Equipment						

1

127.4 Please explain in detail how Concentric decided to apply gradualism and by how much. What does Concentric consider a large change, and what are the criteria used to determine this?

Response:

Please refer to the responses to BCUC IRs 1.125.1 and 1.125.4 that are specific to FBC, but also are relevant for this IR.

128.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-11

Net Salvage Change for Account 474.00 – Meter/Regulator Installations

On page 3-11 of the FEI Depreciation Study, Concentric states the following:

> This study recommends maintaining the net salvage percentage at negative 20 percent. Inclusion of data from the last three years shows a very strong trend to higher negative net salvage rates. The last six three-year rolling bands are all more negative than negative 40 percent. The historical net salvage rate is negative 38 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 30 percent at this time, however given the concept of gradualism, Concentric is recommending maintaining the net salvage at negative 20 percent.

128.1 Please provide a detailed explanation of the factors that resulted in increases in the historical net salvage rate.

Response:

The following response has been prepared by Concentric.

As stated on page 3-11 in the FEI 2017 Depreciation Study and quoted above, the Summary of Book Salvage, shown on page 7-16, indicates progressive increases in the historical net salvage. With the total historical net salvage being negative 38 percent, Concentric views that negative 30 percent would be a reasonable expectation. However, Concentric recommended that any increase be deferred until such time as the increasing trend is verified over a longer period of time.

128.2 Please explain why Concentric is not recommending a change to the rate, despite costs increasing. If the rate is not changed, will this lead to larger net salvage rate changes in future studies? Please explain.

Response:

The following response has been prepared by Concentric.

Concentric is recommending to maintain the negative 20 percent net salvage but increase the net salvage depreciation rate from the approved 1.77 percent (FEI 2014 Depreciation Study) to 3.37 percent (FEI 2017 Depreciation Study).

As stated in the response to BCUC IR 1.126.1, the Concentric recommendations considered the results of the study, in combination with professional judgement which considered such factors as the limited amount of historic data, a comparison to peers and the views of company management. At the next study, Concentric and FEI will evaluate whether a revision to the expected net salvage is appropriate.

128.3 Please explain why the net salvage amount for this account has increased from $3,325,393 to $6,331,397 (as shown in Table D2-4 of the Application) if Concentric is recommending maintaining the net salvage at negative 20 percent. Please provide the calculations.

Response:

The following response has been prepared by Concentric.

Historically the actual costs of removal for account 474.00 – Meter/Regulator Installations have been higher than the actual net salvage provision and currently the net salvage balance for this account is underfunded. While Concentric's recommendation is to maintain a net salvage percentage of negative 20 percent, the net salvage depreciation rate has increased from 1.77 percent to 3.37 percent to offset the accumulated depreciation deficiency residing in the net salvage balance for this account.

128.4 Did Concentric complete a peer comparison of salvage rates for this account? If so, please provide this comparison. If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.127.3.

128.5 Please explain in detail how Concentric decided to apply gradualism.

Response:

Please refer to the responses to BCUC IRs 1.125.1 and 1.125.4 which are specific to FBC but are relevant to this IR and FEI.

129.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 3-12

Net Salvage Change for Account 475.00 – Mains

On page 3-12 of the FEI Depreciation Study, Concentric states the following:

> This study recommends maintaining the currently approved negative 25 percent net salvage rate. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last seven three-year rolling bands are both more negative than negative 30 percent, as are the last six five-year rolling bands. The historical net salvage rate is negative 30 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 30 percent at this time, however given the concept of gradualism, Concentric is recommending maintaining the net salvage at negative 25 percent.

129.1 Please provide a detailed explanation of the factors that resulted in increases in the historical net salvage rate.

Response:

The following response has been prepared by Concentric.

As stated on page 3-12 in the FEI 2017 Depreciation Study and quoted above, the Summary of Book Salvage, shown on page 7-17, indicates progressive increases in the historical net salvage. With the total historical net salvage being negative 30 percent, Concentric views that negative 30 percent would be a reasonable expectation. However, Concentric recommended that any increase be deferred until such time as the increasing trend is verified over a longer period of time and, therefore, recommended maintaining the negative 25 percent net salvage rate.

129.2 Please explain why Concentric is not recommending a change to the rate, despite costs increasing. If the rate is not changed, will this lead to a larger net salvage rate change in future studies? Please explain.

Response:

The following response has been prepared by Concentric:

As stated in the response to BCUC IR 1.126.1, the Concentric recommendations considered the results of the study, in combination with professional judgement which considered such factors as the limited amount of historic data, a comparison to peers and the views of company management. Concentric cannot determine what the net salvage rate will be three to five years in the future and in the next study will evaluate whether a revision to the expected net salvage is appropriate.

129.3 Please explain why the net salvage amount for this account has increased from $6,126,475 to $7,123,809 (as shown in Table D2-4 of the Application) if Concentric is recommending maintaining the net salvage at negative 25 percent. Please provide the calculations.

Response:

The following response has been prepared by Concentric.

While Concentric's recommendation is to maintain a net salvage percentage of negative 25 percent, the net salvage depreciation rate has increased slightly from 0.43 percent to 0.50 percent. Even though the increase in the net salvage depreciation rate is only 0.07 percent, because this account consists of a very large investment, even such a minor change results in a larger increase of the net salvage depreciation expense.

129.4 Did Concentric complete a peer comparison of salvage rates for this account? If so, please provide this comparison. If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.127.3.

129.5 Please explain in detail how Concentric decided to apply gradualism.

Response:

Please refer to the responses to BCUC IRs 1.125.1 and 1.125.4 which are specific to FBC but are relevant to this IR and FEI.

130.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FBC Depreciation Study, p. 4-2

Amortization accounting

On page 4-2 of the FBC Depreciation Study, Concentric states the following:

> FortisBC also proposed amortized accounting for selected accounts in their 2015 study, for balances as of December 31, 2014, on pages III-3, IV-4 and IV-5 of the 2014 Depreciation Study dated August 21, 2015. These recommendations were accepted by the British Columbia Utilities Commission but were not fully implemented by FortisBC.

130.1 Please explain why these recommendations were not fully implemented by FBC.

Response:

The following portion of the response has been prepared by FortisBC:

FBC implemented the results of the FBC 2014 Depreciation Study by applying the remaining life approach for selected general plant accounts, which is a form of amortization accounting that utilizes a survivor curve. The FBC 2014 Depreciation Study was not explicit in differentiating between the application of the remaining life approach and pure amortization accounting for these FBC general plant accounts, and both are considered appropriate methods of amortization accounting. Full implementation of pure amortization accounting is where plant account balances are retired automatically at the end of their amortization period. In this Application, the FBC 2017 Depreciation Study recommends using pure amortization accounting rather than the remaining life approach.

The following portion of the response has been prepared by Concentric:

In the FBC 2014 Depreciation Study, amortization accounting was proposed for several general plant accounts using the remaining life approach. Amortization accounting generally recognizes that vintage costs and associated accumulated depreciation beyond the applicable amortization period are retired at each year end. With strict adherence to amortization accounting, the resultant depreciation rates would theoretically be the reciprocal of the amortization period. Although FBC is amortizing certain general plant accounts according to generally accepted amortization periods, by using a square curve it is not following strict amortization accounting (i.e., annual year end original cost and associated accumulated depreciation retirement). As such, applying a square curve and associated average service life to its applicable general plant accounts using a Remaining Life approach, as FBC is doing, is the correct alternative.

The following portion of the response has been prepared by FortisBC:

Based on further discussions with Concentric Advisors, and considering that amortization accounting is an approved method for these type of accounts for many utilities throughout North America, including FEI, FBC believes implementing fully the strict amortization accounting approach, beginning in 2020, would provide greater simplicity in accounting, as well as alignment between FEI and FBC.

130.2 For each of the accounts where amortization accounting is proposed, please explain if these were accounted for using amortization accounting previously. If not, please explain why FBC is proposing to change to the amortization method for these accounts, and the impact of this change.

Response:

Each of the accounts listed on page D-26 from Section 2 of the Application for which pure amortization accounting is proposed, were previously accounted for by using the remaining life approach which is still considered an appropriate form of amortization accounting as described in the response to BCUC IR 1.130.1. In the FBC 2017 Depreciation Study the depreciation rates for these accounts were developed using the amortization accounting procedure with the assumption that the cost for assets older than the recommended amortization period are retired along with their accumulated depreciation balances. Under the amortization accounting method, the original cost of the assets is depreciated over the estimated life of the assets with depreciation based on the applicable amortization period.

The amortization accounting approach is used where there are numerous units of property and they are difficult to track in sufficient detail. In its pure form, the amortization rate is determined on an estimated average service life of the plant category instead of relying on individual retirement of assets, resulting in an evenly distributed allocation of the asset cost over the total life of the investment.

Since these accounts typically consist of numerous units of property with each retirement unit being a very small portion of depreciable gas plant in service it is very difficult to track this type of plant. For example, Account 394.00 – Tools and work equipment has many small items, such as wrenches, which are a very small component of depreciable plant. As a result, Concentric Advisors recommends the use of amortization accounting for these types of accounts.

Under the amortization accounting approach, an asset is retired at the end of its original estimated useful life (when the net book value reaches zero) with no recorded gains or losses on retirement. For example, if an asset's estimated service life is 15 years, under the amortization approach, the annual depreciation expense recorded should be 1/15th of the

assets value each year for 15 years. At the end of 15 years, when the asset is retired under the Amortization Accounting approach, the accumulated depreciation reserve should be equal to the original cost, resulting in no gain or loss on retirement of the asset.

There is no impact on depreciation expense as a result of this change as shown in the table below.

Class	Description	Cost as of Dec. 31, 2017 based on old method ('000s)	Depreciation rate based on the old method	Depreciation expense based on the old method ('000s)	Cost as of Dec. 31, 2017 based on amortization accounting ('000s)	Depreciation rate based on amortization accounting	Depreciation Expense based on amortization accounting ('000s)
		a	b	a*b	c	d	c*d
391.00	Office furniture and equipment	$8,472	2.94%	$249	$5,632	4.42%	$249
391.10	Computer hardware	$32,313	7.92%	$2,559	$11,843	21.60%	$2,558
391.20	Computer software	$75,295	4.37%	$3,290	$36,720	8.96%	$3,290
391.60	AMI computer software	$9,597	10.00%	$960	$9,597	10.00%	$960
394.00	Tools and work equipment	$13,863	2.61%	$362	$8,809	4.11%	$362
397.00	Communciations structures and equipment	$16,843	2.67%	$450	$13,111	3.44%	$451
397.10	Fiber	$11,996	6.97%	$836	$11,996	6.97%	$836
397.20	AMI communciations structures and equipment	$4,970	6.67%	$331	$4,970	6.67%	$331
370.10	AMI Meters	$37,461	6.25%	$2,341	$37,461	6.25%	$2,341

131.0 Reference: DEPRECIATION STUDY

Exhibit B-1-1, Appendix D2, FEI Depreciation Study, p. 4-1

Amortization accounting

On page 4-1 of the FEI Depreciation Study, Concentric proposes amortization accounting for a number of accounts.

131.1 For each of the accounts where amortization accounting is proposed, please explain if these were accounted for using amortization accounting previously. If not, please explain why FEI is proposing to change to the amortization method for these accounts, and the impact of this change.

Response:

To clarify, each of the accounts listed in the table on page 4-2 of the FEI 2017 Depreciation Study have been subject to pure amortization accounting since 2012 and therefore, no change in methodology is being proposed. FEI has previously received BCUC approval in its previous depreciation studies to apply pure amortization accounting to these accounts.

132.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-1, Section D3.1, p. D-32; Exhibit B-1-1, Appendix D3-1, pp. 2–3; Exhibit B-1-1, Appendix D3-2, pp. 2–3

Introduction and Summary

On page D-32 of the Application, FortisBC states that it is requesting approval to adopt updated lead-lag days for the calculation of the cash working capital requirements in FEI and FBC Annual Review 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." [*Emphasis added*]

132.1 Please explain and discuss the factors or criteria which FEI and FBC will use to evaluate when a "refresh" of the approved lead-lag days is needed and how often the assessment will take place.

Response:

The FortisBC financial accounting team uses judgement and assesses several factors when determining whether a refresh of the approved lead-lag study is required. FEI's last lead-lag study was performed in 2009, whereas FBC's last lead-lag study was performed in 2005. Since those last updates, there have been changes to the lead lag days due to changes in legislation, internal practices, updated contracts, etc., all of which require FortisBC to undertake a more detailed assessment to determine the effect on the Utilities' lead-lag for Cash Working Capital. Given the amount of time that has passed since the previous studies were approved and in setting a five year framework from 2020 through 2024, the Utilities' next opportunity to refresh the studies may not be until 2025. FortisBC believes it is good business practice to refresh the lead-lag studies for both Companies at this time. In addition, FortisBC is seeking to align the various methodologies between FEI and FBC where appropriate to do so.

132.2 Please explain what prompted FortisBC to perform a lead-lag study for each of FBC and FEI at this time.

Response:

Please refer to the response in BCUC IR 1.132.1.

132.2.1 As part of the above response, please explain when FBC's last lead-lag study was performed, including the BCUC order number approving it.

Response:

FBC last conducted a lead-lag study in 2005. Although the study itself was not filed, the lag (lead) results were examined in Information Requests and the financial schedules containing the working capital calculation was approved by BCUC Order G-52-05.

FEI's previous lead-lag study was performed in 2009 (2009 Lead-Lag Study) as part of the Terasen Gas Inc. 2010-2011 Revenue Requirements Application (TGI 2010-2011 RRA). It appears that the 2009 Lead-Lag Study was independently reviewed by KPMG Management Consultants (KPMG), and KPMG's review report (which included its findings and recommendations) was included with the 2009 Lead-Lag Study in Appendix I-2 of the TGI 2010-2011 RRA.

132.3 Please discuss what process has been undertaken by FortisBC to validate and/or review the methodology, approach and results of the 2018 lead-lag studies for FEI and FBC, including whether an independent review process was undertaken.

Response:

There was no review of the FEI and FBC 2018 Lead-Lag Studies by an external consultant. However, the incremental external review and associated costs to be incurred were not necessary as FortisBC used the same model and methodology consistent with the one established as part of the Terasen Gas Inc 2010-2011 Revenue Requirement Application. That 2009 Lead-Lag study was reviewed independently by KPMG and approved by the BCUC. With a previously established lead-lag model and no proposed change in methodology, the update to the lead lag study essentially required updating the model with more recent financial data and transactions derived from FortisBC's SAP system. Internal management also reviewed the study based on an understanding of FortisBC's operations and regulatory practices.

In KPMG's review of the 2009 Lead-Lag Study, as included in Appendix I-2 of the Terasen Gas Inc 2010-2011 Revenue Requirement Application, KPMG stated in section 1.0:

Following the review of TGI/TGVI's Study, KPMG found that the Study:

- Is complete with respect to the inclusion of all major revenue and expense items as compared to the financial statements;

- Does not materially exclude any revenue and expense items as compared to the financial statements;
- Appropriately uses the 2007 study period to reflect activity expected in the 2010/11 forecast years;
- Appropriately and necessarily includes an adjustment for Carbon Tax introduced in 2008;
- Uses averaging assumptions for some lag periods that are reasonable and correct in calculation;
- Uses system generated data for the remaining lag periods which are reasonable and correct in calculation;
- Is consist with principles and guidance offered in FERC NOPR RM84-9-000, and in the approach used by utilities in other jurisdictions; and
- Excludes financial items from its net revenue lag calculation, which KPMG does not find to be inappropriate.

132.3.1 If an independent review was performed, please provide a copy of the independent review report and discuss the key findings.

Response:

Please refer to the response to BCUC IR 1.132.3.

132.3.2 If an independent review was not performed, please explain why not.

Response:

Please refer to the response to BCUC IR 132.3.

On page 3 of the FEI and FBC 2018 Lead-Lag Studies included in Appendix D3-1 and D3-2, respectively, FortisBC states that the methodology used in the studies to determine the lead lag days for individual revenue and expenditure items is "generally similar" for all regulated utilities.

132.4 Please provide support for the above statement with respect to how the methodology used by FortisBC to determine the lead lag days for individual revenue and expenditure items in the 2018 Lead-Lag Studies is "generally similar" to other regulated utilities. In what ways are the methodologies similar or different, and why does FortisBC consider the differences, if any, to be appropriate?

Response:

FortisBC stated that its approach to calculating lead-lag days is "generally similar" to other regulated utilities based on information included in its previous studies and publicly available utility industry information. As part of determining revenue requirements, regulated utilities estimate the amount of working capital for inclusion in rate base and this relies on the preparation of lead-lag studies. The determination of revenue lag and expense lead requires the extraction actual financial transactions from a utility's accounting system. The net lag ratio of the utilities' cash operating expenses is then used to estimate the cash working capital allowance. This is not a new concept for utilities and the approach has been applied consistently with FortisBC's previous lead-lag studies. Specifically, per the KPMG Lead Lag Study Review included on page 22 of Appendix I-2 of the Terasen Gas Inc. 2010-2011 Revenue Requirement Application, which stated the following:

> TGI/TGVI's approach is also consist with the guidance offered in FERC NOPR RM84-9-000 and is in principle alignment with what utilities prepare for regulators in other jurisdictions. With respect to the differences between utilities and jurisdictions on the matter of financial items, KPMG does not consider these items to be inappropriately excluded from the TGI/TGVI Study. *(6.0 KPMG Findings and Recommendations)*

While a formal survey on lead-lag studies methodology was not recently conducted, in a 2008 survey of 26 Canadian utilities, 80 percent of the respondents indicated that they used a lead-lag study to calculate their cash working capital allowance.

FortisBC also states on page 2 of the studies "Lag days for total revenue and lead days for total expenditures are calculated using 2017 actual data, the most recent year of actual data available to prepare this study."

132.5 Please explain why FortisBC considers it appropriate to rely on one year of actual data rather than multiple years of data, such as 3-years of actual data, to prepare the 2018 lead-lag studies.

Response:

In the KPMG Lead-Lag Study Review in Appendix I-2 of the Terasen Gas Inc. 2010-2011 Revenue Requirement Application, KPMG stated:

> The utilities vary slightly in the assumptions used, however whether six or twelve months of data has been analyzed or if average service time assumptions or invoice sampling is used, the information provided in the lead-lag studies is representative of each utility's recent business activity and is therefore assumed to be representative of business activity expected in the forecast years. The methodology and approach used in the TGI/TGVI Study is similar to that of these other utilities. *(5.0 Comparison to Other Utilities)*

As KPMG previously stated, certain utilities may rely on only six months of data to forecast lead/lag days. Using 3-years of historic data would likely not be any more representative of business activity than the twelve months of data used in the updated 2018 Lead-Lag Studies. It also needs to be considered that using an older average data set from three years ago may not be the most relevant data for forecast future activity. Based on the combination of all these factors, FortisBC chose to use twelve months of data.

133.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-1, Section D3.2, pp. D-33 – D-34; Exhibit B-1-1, Appendix D3-1, pp. 4, 6–8, 10

2018 Lead-Lag Study for FEI

Table D3-1 on page D-34 of the Application summarizes the FEI 2018 Lead-Lag Study as follows compared to the approved 2009 Lead-Lag Study:

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							

On page 6 of Appendix D3-1, FEI states that sales revenue lag days are derived from the assessment of three time frames: service lag, billing lag, and collection lag.

Table I-1 on page 7 of Appendix D3-1 shows the calculation of the sales revenue lag days in the 2018 Lead-Lag Study for FEI by rate class as follows:

Table I-1: Calculation of Sales Revenue Lags

Customer Class	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Residential	15.2	0.0	25.1	40.3
Commercial	15.2	0.0	22.6	37.8
Industrial	15.2	13.8	18.7	47.7
Bypass and Special Rates	15.2	0.0	22.4	37.6

133.1 Please explain with reference to the three times frames assessed (i.e. service lag, billing lag and collection lag) why the revenue lag days for each customer class of rates has changed from the 2009 Lead-Lag Study, including the underlying reasons why the service lag, billing lag or collection lag may have changed (e.g. change to invoicing policies or procedures).

Response:

The change in revenue lag days from the FEI 2009 Lead-Lag Study is primarily associated with updating the results in collection lag for Residential and Industrial customer classes. There were no significant changes in the results for service lag and billing lag.

Residential collection lag increased from 23.1 days in the FEI 2009 Lead-Lag study to 25.1 days in the most recent FEI 2018 Lead-Lag Study. FEI believes this increase is likely attributable to the increased use of online banking amongst residential customers. More specifically, online banking provides customers with the opportunity to pay their bills more closely to the invoice due date in a convenient way.

Industrial collection lag increased from 16.0 days in 2009 to 18.7 days in 2018. The main factor behind this increase is likely related to the increased use of electronic payments which creates additional lag in terms of when the funds clear through the bank.

Table II-1 on page 8 of Appendix D3-1 shows the calculation of other revenue lag days in the 2018 Lead-Lag Study for FEI as follows:

Table II-1: Calculation of Other Revenue Lags

Other Revenue	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Late Payment Charges	0.0	30.0	23.8	53.8
Connection Charges	15.2	0.0	23.8	39.0
Other Utility Income	15.2	0.0	23.8	39.0

On page 7 of Appendix D3-1, FEI states that Late Payment Charges are added to the bill that follows after the bill where the late payment occurred and "then that bill is assumed to be collected by the invoice date." FEI also states on the same page that "the majority of payments are due 22 days following the invoiced date."

133.2 Please provide support for FEI's assumption that Late Payment Charges are collected by the invoice date on the bill that follows after the bill where the late payment occurred. What is FEI's experience based on actual historical data?

Response:

A summary of the actual Late Payment Charge data for 2018 is provided below which shows the number of days between billing the charge and when it is collected. Using this 2018 data, the weighted Collection Lag was 51.2 days, which is higher than the 23.8 days used in the lead lag study and discussed further in the response to BCUC IR 1.133.2.1.

The 51.2 days was determined by first weighting the actual late payment charges by the number of days outstanding, and then multiplying the weighted amount by the payment day mid-point. For example, the weighted collection lag days of 10.2 days for the 61-90 Days category was determined by multiplying 13.5 percent by 75.5 days ((61+90)/2). For the "Over 120 Days" category, the payment day mid-point used is 242.5 days ((120+365)/2).

Since there is no impact of this alternate method on the Total Revenue lag days or Cash Working Capital amount included in rate base due to the relatively small weighting of Late Payment Charges in FEI's overall cash working capital calculation, FEI has not revised its proposals.

Summary of 2018 Late Payment Charges

Payment Days	Sum of $ Amounts (000s)	% of $ Amounts	Weighted Collection Lag
Zero	15	0.6%	-
1 - 22 Days	849	32.6%	3.7
23 - 24 Days	80	3.1%	0.7
24 - 30 Days	224	8.6%	2.3
31 - 60 Days	765	29.4%	13.4
61 - 90 Days	352	13.5%	10.2
91 - 120 Days	164	6.3%	6.6
Over 120 Days	152	5.9%	14.3
Grand Total	**2,602**	**100%**	**51.2**

133.2.1 Please provide the calculation for the Collection Lag of 23.8 days for Late Payment Charges with supporting explanation.

Response:

The collection lag of 23.8 days was calculated as the average of the collection lag days for all Residential and Commercial Customers Sales Revenues (provided in Table I-1 in Appendix D3.1). Given Late Payment Charges are included on the customer's bill, the average collection lag for Residential and Commercial Customers Sales Revenues was used for the Late Payment Charge collection lag, under the assumption that customers pay their bill in full, including both the sales revenue and late payment portions of their bill.

The table below summarizes the collection lag of the Residential and Commercial Customer Classes.

	Collection Lag
Residential Customers	25.1
Commercial Customers	22.6
Average	23.8

133.3 Please explain with reference to the three times frames assessed (i.e. service lag, billing lag and collection lag) why the revenue lag days for Late Payments Charges has increased from 38.3 days in the 2009 Lead-Lag Study to 53.8 days in the 2018 Lead-Lag Study, including the underlying reasons why the service lag, billing lag or collection lag may have changed (e.g. change to invoicing policies or procedures).

Response:

Of the three time frames assessed, the main driver of the increase in Late Payment Charge lag in the updated Lead-Lag Study is the billing lag, which is partly offset by the removal of the Service Lag, as shown in the table below:

	2018 Study	2009 Study *	Variance
Service Lag	0.0	15.2	(15.2)
Billing Lag	30.0	0.3	29.7
Collection Lag	23.8	22.8	1.0
Total Lag	53.8	38.3	15.5

**weighted average lags of all tariff revenues classes.*

In the current study, FEI has added a 30-day Billing Lag into the Late Payment Charge Lag calculation to account for the longer time period of not receiving payment as compared to revenues more generally. The nature of the Late Payment Charge is that the customer is being charged for not paying their invoice for service received in a prior time period so the addition of the 30 day Billing Lag, included in the FEI 2018 Lead-Lag Study, is a more accurate refinement.

In the FEI 2009 Lead-Lag Study, the approach assumed the lags associated with Late Payment Charges would be similar to the lag seen across all tariff revenue classes, which assigned a lag to the Service. The Service lag has been removed (now zero) in the FEI 2018 Lead-Lag Study.

On page D-33 of the Application, FEI states: "The increase in expenditures 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."

On page 4 of the Appendix D3-1, FEI states that expense lead (lag) days are derived from the assessment of two time frames: service lead (lag) and payment lead (lag).

Table IV-1 on page 10 of Appendix D3-1 shows the calculation of O&M leads (lags) is broken down into six broad categories:

Table IV-1: Calculation of O&M Leads (Lags)

	2017 Actual Expenses	Weighting Factor	Service Lead (Lag)	Pyament Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	$ 125,234,010	48%	22.7	10.7	33.3	15.9
Contractors	41,744,237	16%	12.1	37.9	50.0	7.9
Materials	11,348,559	4%	15.2	32.0	47.2	2.0
Computer Costs	15,964,210	6%	42.7	(35.3)	7.3	0.4
Insurance	5,283,487	2%	170.3	(318.0)	(147.8)	(3.0)
Other O&M	31,539,713	12%	15.2	25.8	41.0	4.9
Total O&M Expenses	$ 262,653,928	100%				33.2

133.4 Please explain with reference to the six broad categories of O&M expenses why the service lead for O&M expenditures has increased from 25.5 days in the 2009 Lead-Lag Study to 33.2 days in the 2018 Lead-Lag Study. Which categories have a longer service lead now and why?

Response:

In preparing the response to this IR, FEI noticed several calculation errors in Table IV-1: Calculation of O&M Leads (Lags) in Appendix D3-1 of the Application. The revised corrected table is as follows, and will be included in an Errata to be filed in the near future.

	2017 Actual Expenses	Weighting Factor	Service Lead (Lag)	Pyament Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	$ 125,234,010	55%	22.7	10.7	33.3	18.5
Contractors	41,744,237	18%	12.1	37.9	50.0	9.2
Materials	11,348,559	5%	15.2	32.0	47.2	2.4
Computer Costs	15,964,210	7%	42.7	(35.3)	7.3	0.5
Insurance	5,283,487	2%	170.3	(318.0)	(147.8)	(3.5)
Other O&M	26,211,979	12%	15.2	25.0	40.2	4.7
Total O&M Expenses	$ 225,786,482	100%				31.8

Based on the corrected table above, the updated O&M expense lead changed from 33.2 days to 31.8 days. This change results in a corresponding change to Schedule II-1 – FEI example of change in Cash Working Capital Requirements in Appendix D3-1 of the Application, as follows:

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	31.8	7,827,635	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	**34.2**	35,284,737	1,032,444	**32.8**	33,898,280
28							
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.8**			**6.2**	
30							
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$16,406**			**$17,537**	
32							

A summary of the net change in O&M lead days, using the revised results provided above, is included below.

Total Expense Lead for O&M 2018 Study vs. 2009 Study

O&M Expenses	2018 Study	2009 Study	Variance
Payroll & Benefits	18.5	7.3	11.2
Contractors	9.2	9.7	(0.5)
Materials	2.4	1.0	1.4
Computer Costs	0.5	1.9	(1.4)
Insurance	(3.5)	-	(3.5)
Other O&M	4.7	5.6	(0.9)
Total O&M Expenses	**31.8**	**25.5**	**6.3**

The main changes between the 2009 and 2018 Lead-Lag Studies' results were related to Payroll & Benefits and Insurance.

Payroll & Benefits increased the total expense lead by 11.2 days, primarily due to the 2018 study recognizing the service lead for incentive pay. This service lead is the result of employees

providing service to FEI throughout the year while the related incentive is not paid until the following year. The previous study did not account for this service lead.

Insurance decreased the total expense lead by 3.5 days as insurance costs were not included in the previous FEI 2009 Lead-Lag Study. Insurance cost invoices are generally paid for in advance of the coverage period; as a result there is a negative payment lead on Insurance costs.

133.5 Please explain why the service lead for PST has increased from 37.1 days in the 2009 Lead-Lag Study to 45.8 days in the 2018 Lead-Lag Study.

Response:

The change in PST lead days from 37.1 days to 45.8 days is primarily attributable to a change in the payments terms of when PST remittances are due as a result of the new BC PST legislation that was enacted on April 1, 2013. The FEI 2009 Lead-Lag Study used 2007 actual data when, at the time, PST was due on the 15th of the month following for January to March 2007 and on the 23rd of the month following for April to December 2007 pursuant to the PST legislation that existed in those time periods. In the FEI 2018 Lead-Lag Study, that used 2017 actual data, PST remittances are now due on the last day of the following month, pursuant to the current PST legislation, which as a result increased the lead-time on PST.

134.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-1, Section D3.2, pp. D-34, D-36; Exhibit B-1-1, Appendix D3-2, pp. 5, 8, 9, 11

2018 Lead-Lag Study for FBC

On page D-34 of the Application, FBC states that the methodology used in its 2018 Lead-Lag Study has been aligned to FEI's current and previous studies by including GST in the cash working capital calculations and excluding interest expense, as well as, using actual revenue and expenditure data in this study rather than the high level assumptions used in the previously approved method.

134.1 Please provide the impact on the net lead-lag days and cash working capital from including GST in the cash working capital calculations and excluding interest expense.

Response:

To clarify and assist in the response below, the calculation of cash working capital is derived as net lead-lag days x total annual expenditures / 365 days.

For FBC, including GST in the cash working capital calculation decreased the net lead-lag days by 0.2 days. This has a similar effect as the direct deduction of GST that was used in the calculation of the Working Capital Allowance in the previously approved method. However, adding GST to the total expenditures portion of the equation used to derive cash working capital, resulted in an overall increase to the cash working capital requirements of $0.104 million.

Excluding interest expense from the cash working capital calculation increased net lead-lag days by 6.3 days. This increase in net lead lag days was partially offset by the reduction in total expenditures, however the net result was an increase to cash working capital of $3.862 million.

134.1.1 Please explain why the proposed lead days for GST for FBC is 45.4 days compared to 39.7 days[148] for FEI. Please include a discussion on how the lead days were determined and why FortisBC considers the difference of 5.7 days between FBC and FEI to be reasonable.

[148] As shown in line 23 of Table D3-1 on page D-34 of the Application.

Response:

The main reason behind the 5.7 day difference in lead days between FEI and FBC is related to the difference that seasonality has on FEI's and FBC's revenues and the associated GST. FEI's revenues are more heavily weighted towards the colder winter months when gas usage, and the accompanying GST collection, is at its highest. In the warmer summer months FEI's revenues, along with GST collection on customer bills, significantly decreases. As a result, FEI's net GST position in the warmer months is in a refund position.

Similar to FEI, FBC's revenue also experiences a heavier weighting during the colder winter months when electricity is used for heating and the accompanying GST collection is at its highest. However, FBC's revenues and GST collection also increase during the spring and summer months when electricity is used for cooling purposes. As a result FBC is typically in a GST tax owing position and this causes FBC's net GST lead days to be longer than FEI's.

134.2 Please provide the high level assumptions used in the previously approved lead-lag study method for each type of revenue and expense item.

Response:

Please see the table below summarizing the high-level assumptions used under the previous methodology.

	Assumptions in FBC Previously Approved Method
Sales Revenue	
Residential Tariff Revenue	Assumed consumption occurred consistently throughout one or two-month period. Payments were due in 17 days and 22 days for monthly and bi-monthly billings respectively, and a certain proportion of monthly and bi-monthly billings was estimated for each revenue class.
Commercial Tariff Revenue	
Wholesale Tariff Revenue	
Industrial Tariff Revenue	
Lighting Tariff Revenue	
Irrigation Tariff Revenue	
Other Revenues	
Apparatus and Facilities Rental	Assumed consumption occurred consistently throughout the year for Apparatus Revenue. Invoice was issued on July 1st with payments due in 30 days.

	Assumptions in FBC Previously Approved Method
Contract Revenue	Assumed consumption occurred consistently throughout the month. Invoices were issued on the 10th day of the month following for Management Fees and at the end of the same month for Subcontract Revenue. Payments were due in 30 days.
Transmission Access Revenue	Assumed consumption occurred consistently throughout the month. Invoices were issued and payments were collected immediately, that is, Billing Lag and Collection Lag were both 0 days.
Late Payment Charges	Assumed late payment charges were incurred and billed on the same date as the invoice following the invoice that was paid late, and payments were collected in 60 days.
Connection Charge	Assumed a mix of connections charges which were collected at the time the work was completed and reconnection charges which were billed in the first month following the reconnection.
Other Recoveries	Assumed consumption occurred when services were provided. Invoices were issued 30th day of the month following for Sundry Revenue and at the end of the same month for Wheeling Revenue. Payments were due in 30 days.
Expenditures	
Power Purchases	Assumed consumption occurred consistently throughout the month and the year for monthly power purchases and the Brilliant Power Purchase Agreement (“BPPA”) return on capital payment, respectively. Invoices were billed on the 1st of the following month for power purchase related to O&M and twice a year on May 5th and Nov 5th for BPPA return on capital payment were due within 21 days.
Water Fees	Assumed consumption occurred consistently throughout the year and invoices were paid at the end of March and the end of September.
Wheeling	Assumed consumption occurred consistently throughout the month and invoices were issued on the 5th day of the following month with payments due in 20 days.
Operation & Maintenance	Assumed consumption occurred consistently throughout the service period and payment were made per payment terms.
Property Tax	Assumed consumption occurred consistently throughout the year and invoices were paid on July 4th.

	Assumptions in FBC Previously Approved Method
Income Tax	Assumed consumption occurred consistently throughout the month and invoices were paid at the end of the same month.
Interest Expense	Assumed consumption occurred consistently throughout the period and invoices were paid the same day when interest was due.

Table D3-2 on page D-36 of the Application summarizes the FBC 2018 Lead-Lag Study as follows compared to the previously approved lead-lag study:

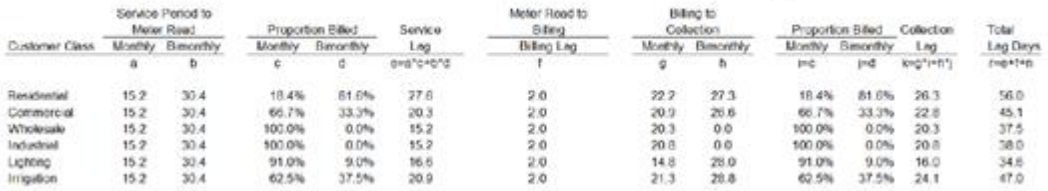
Table D3-2: Summary of FBC lead-lag study results

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							

On page 5 of Appendix D3-2, FBC states that sales revenue lag days are derived from the assessment of three time frames: service lag, billing lag, and collection lag.

Table I-1 on page 8 of Appendix D3-2 shows the calculation of the sales revenue lag days in the 2018 Lead-Lag Study for FBC by rate class as follows:

Table I-1: Calculation of Sales Revenue Lags



Customer Class	Service Period to Meter Read		Proportion Billed		Service Lag	Meter Read to Billing	Billing to Collection		Proportion Billed		Collection Lag	Total Lag Days
	Monthly	Bimonthly	Monthly	Bimonthly		Billing Lag	Monthly	Bimonthly	Monthly	Bimonthly		
	a	b	c	d	e=a*c+b*d	f	g	h	i=c	j=d	k=g*i+h*j	l=e+f+k
Residential	15.2	30.4	18.4%	81.6%	27.8	2.0	22.2	27.3	18.4%	81.6%	26.3	56.0
Commercial	15.2	30.4	66.7%	33.3%	20.3	2.0	20.3	20.6	66.7%	33.3%	22.8	45.1
Wholesale	15.2	30.4	100.0%	0.0%	15.2	2.0	20.3	0.0	100.0%	0.0%	20.3	37.5
Industrial	15.2	30.4	100.0%	0.0%	15.2	2.0	20.8	0.0	100.0%	0.0%	20.8	38.0
Lighting	15.2	30.4	91.0%	9.0%	16.6	2.0	14.8	28.0	91.0%	9.0%	16.0	34.6
Irrigation	15.2	30.4	62.5%	37.5%	20.9	2.0	21.3	20.8	62.5%	37.5%	24.1	47.0

FBC further states on page 8 that "During the test period FBC's customers were billed two days subsequent to the meter reading date."

134.3 Please explain with reference to the three times frames assessed (i.e. service lag, billing lag and collection lag) why the sales revenue lag days for each customer class of rates has changed from the previously approved lead-lag study, including the underlying reasons why the service lag, billing lag or collection lag may have changed (e.g. change to invoicing policies or procedures).

Response:

The table below summarizes the calculation of Lead-Lag Days associated with Sales Revenues in the previously approved method.

Customer Class	Service Period to Meter Read		Proportion Billed		Service Lag	Meter Read to Billing	Billing to Collection		Proportion Billed		Collection Lag	Total Lag Days
	Monthly	Bimonthly	Monthly	Bimonthly		Billing Lag	Monthly	Bimonthly	Monthly	Bimonthly		
	a	b	c	d	e=a*c+b*d	f	g	h	i=c	j=d	k=g*i+h*j	l=e+f+k
Residential	15.2	30.4	14.6%	85.4%	28.2	1.0	17.0	22.0	14.6%	85.4%	21.3	50.5
Commercial	15.2	30.4	19.6%	80.4%	27.4	1.0	17.0	22.0	19.6%	80.4%	21.0	49.4
Wholesale	15.2	30.4	100.0%	0.0%	15.2	1.0	17.0	22.0	100.0%	0.0%	17.0	33.2
Industrial	15.2	30.4	100.0%	0.0%	15.2	1.0	17.0	22.0	100.0%	0.0%	17.0	33.2
Lighting	15.2	30.4	16.2%	83.8%	27.9	1.0	17.0	22.0	16.2%	83.8%	21.2	50.1
Irrigation	15.2	30.4	40.3%	59.7%	24.3	1.0	17.0	22.0	40.3%	59.7%	20.0	45.3

The updated FBC 2018 Lead-Lag Study used actual 2017 data, which would provide the actual percentage split of monthly and bimonthly billings as well as the actual collection lag. As a result of using this actual data, the weighted Sales Revenues lag has been increased by 2.6 days.

Collection Lag:

The weighted Sales Revenues lag increased by 3.8 days mainly due to:

- A 4.5 days increase due to longer collection lags for most categories in the FBC 2018 Lead-Lag Study than the assumed collection lag of 17 days and 22 days for monthly and

bi-monthly billings, respectively, that was used in the previously approved method; offset by;

- A (0.7) days decrease due to a higher proportion of monthly billings compared to bimonthly billings in the FBC 2018 Lead-Lag Study, as monthly billings have a lower collection lag than bimonthly billings.

Billing Lag:

The weighted Sales Revenues lag increased by 1 day because the billing lag days have been changed from 1 day in the previously approved method to 2 days in the updated 2018 Lead-Lag Study. The previously approved method used high level assumptions while the 2018 Lead-Lag Study was based on the 2017 actual data (see the table below).

Billing Lag Days (a)	Billed Amount ($000s) (b)	Billed Amount % (c)	Weighted Billing Lag (d) = (a)*(c)
0 days	$ 141,256	35.9%	-
1 days	$ 151,940	38.7%	0.4
2 days	$ 21,212	5.4%	0.1
3 or more days	$ 78,565	20.0%	1.4
Total	**$ 392,973**	**100.0%**	**1.9**

The “3 or more days” group mainly includes large power customers (Wholesale and large Industrial customers) and it normally takes about 7 days to bill those customers due to the manual billing process used, thus the weighted billing lag for “3 or more days” group is calculated as 7 x 20.0% = 1.4 days.

Service Lag:

There were no changes in the service lag days assumption in the updated FBC 2018 Lead-Lag Study compared to the previously approved lead-lag day assumptions. However, weighted Sales Revenues lag decreased by (2.2) days due to a higher proportion of monthly billings compared to bimonthly billings in the FBC 2018 Lead-Lag Study (monthly billings have a lower service lag than bimonthly billings).

134.4 Please discuss whether the two-day billing lag is consistent with FBC's expectation during the proposed MRP term or if it was a one-time occurrence applicable to the 2017 test period data.

Response:

As discussed in the response to BCUC IR 1.134.3, the two-day billing lag is based on the actual 2017 data and generally consistent with FBC's expectation during the proposed MRP term.

Table II-1 on page 9 of Appendix D3-2 shows the calculation of other revenue lag days in the 2018 Lead-Lag Study for FBC as follows:

Table II-1: Calculation of Other Revenue Lags

Other Revenue	Service Lag a	Billing Lag b	Collection Lag c	Total Lag Days d=a+b+c
Apparatus and Facilities Rental	180.1	(119.7)	29.6	90.0
Contract Revenue	15.2	17.0	30.0	62.2
Transmission Access Revenue	15.2	20.0	30.0	65.2
Late Payment Charges	0.0	30.0	24.0	54.0
Connection Charge	11.2	1.5	17.8	30.5
Other Recoveries	15.2	19.3	28.9	63.4

134.5 Please explain with reference to the three times frames assessed (i.e. service lag, billing lag and collection lag) why the other revenue lag days for each type of other revenue has changed from the previously approved lead-lag study, including the underlying reasons why the service lag, billing lag or collection lag may have changed (e.g. change to invoicing policies or procedures).

Response:

The Other Revenue lag days in the FBC 2018 Lead-Lag Study are based on the updated assumptions and current billing practices, customer contracts, and payment terms which are shown in the table below (please refer to the response to BCUC IR 1.134.2 for assumptions used in the previously approved method).

Other Revenue	2018 Study
Apparatus and Facilities Rental	Assumed consumption occurred consistently throughout the year for Apparatus Revenue. Invoices are issued on September 1st based on the current billing practice. Payments are due in 30 days.

Other Revenue	2018 Study
Contract Revenue	Assumed consumption occurred consistently throughout the month. Invoices are billed 10 or 20 days in the month following based on the current billing practices and customer contracts. Payments are due in 30 days.
Transmission Access Revenue	Assumed consumption occurred consistently throughout the month. Invoices are billed 20 days in the month following based on the current billing practice. Payments are due in 30 days.
Late Payment Charges	Late payment charges are incurred and billed on the same date as the invoice following the invoice that is paid late. The collection lag is calculated as the average collection lag of tariff revenues, a similar method as used for collection lag for Late Payment Charges in FEI's 2018 Lead-Lag Study.
Connection Charge	A mix of connections charges which are collected at the time the work is completed and reconnection charges which are billed in the first month following is used in the calculation of the lag days. The 2018 Lead-Lag Study shows a higher percentage of connection charges compared to reconnection charges.
Other Recoveries	Assumed consumption occurred consistently throughout the month. Invoices are issued 20 days in the month following for Sundry Revenue and Wheeling Revenue and payments are due in 30 days.

On page 5 of the Appendix D3-2, FBC states that expense lead (lag) days are derived from the assessment of two time frames: service lead (lag) and payment lead (lag).

Tables III-1 and IV-1 on page 11 of Appendix D3-2 show the calculation of power purchase, water fees, and wheeling leads (lags).

134.6 Please explain with reference to the three times frames assessed (i.e. service lead and payment lead) why power purchase and wheeling lead days have increased changed from the previously approved lead-lag study (from 41.7 days to 51.5 days and 40.2 days to 46.9 days, respectively), including the underlying reasons why the service lead, payment lead or expense lead may have changed.

Response:

The payment lead (lag) days for Power Purchases and Wheeling in the 2018 Lead-Lag Study were calculated based on the 2017 actual data, while the previously approved method used high level assumptions (please see the response to BCUC IR 1.134.2).

Power Purchases:

Service leads were assumed to be 15.2 days for power purchases with BC Hydro, Powerex and Waneta Expansion Capacity Agreement (WAX CAPA), and 182.5 days for the Brilliant Power

Purchase Agreement (BPPA) in the FBC 2018 Lead-Lag Study, all of which remained consistent with the previously approved method.

With regard to payment lead, the FBC 2018 Lead-Lag Study showed a payment lead of 35.8 for power purchases based on the actual payment terms, which increased from the assumed 21 lead days in the previously approved method. The other significant driver in the change to payment lead related to FBC entering into the WAX CAPA in 2015 which has a longer-than-average payment term. Payment Lag for the BPPA remained relatively consistent: (129.2) days in FBC 2018 Lead-Lag Study compared to the (128.0) days assumption in the previously approved method.

As a result of the changes in the payment lead (lag) discussed above, the weighted lead for Power Purchases increased from 41.7 days to 51.5 days.

Wheeling:

There was no change in the 15.2 days service lead in the 2018 Lead-Lag Study and the previously approved method.

Payment lead increased by 6.7 days from the assumed 25 days in the previously approved method to 31.7 days in the FBC 2018 Lead-Lag Study based on the actual payment terms.

Table V-1 on page 11 of Appendix D3-2 shows the calculation of O&M leads (lags) is broken down into seven broad categories as follows:

Table V-1: Calculation of O&M Leads (Lags)

	2017 Actual Expenses	Weighting Factor	Service Lead (Lag)	Pyament Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	23,233	49%	18.8	7.5	26.3	13.0
Contractors	14,100	30%	11.4	29.0	40.4	12.1
Rental of T&D Facilities	3,126	7%	182.5	(127.7)	54.8	3.6
Office Leases	518	1%	15.2	(30.4)	(15.2)	(0.2)
Computer Costs	2,006	4%	41.6	(39.1)	2.5	0.1
Insurance	880	2%	182.5	(342.2)	(159.7)	(3.0)
Other O&M	3,326	7%	15.2	26.7	41.9	3.0
Total O&M Expenses	47,189	100%				28.6

134.7 Please explain with reference to the seven broad categories for O&M expenses why the expense lead for O&M expenditures has increased from 20.3 days in the previously approved study to 28.6 days in the 2018 Lead-Lag Study.

Response:

A comparison of the FBC 2018 Lead-Lag Study and the previously approved lead-lag day assumptions for O&M expenses is provided below.

O&M Expense Comparison 2018 vs Previously Approved Method

O&M Expenses	2018 Study	Previously Approved Method	Variance
Payroll & Benefits	13.0	4.5	8.5
Contractors	12.1	12.8	(0.7)
Rental of T&D Facilities	3.6	3.2	0.4
Office Leases	(0.2)	(0.2)	0.0
Computer Costs	0.1	0.0	0.1
Insurance	(3.0)	(4.7)	1.7
Other O&M	3.0	4.7	(1.7)
Total O&M Expenses	**28.6**	**20.3**	**8.3**

The main increases were related to:

- Payroll & Benefits increased by 8.5 days – the Payroll data in the FBC 2018 Lead-Lag Study was broken down between salaried and hourly payroll categories which gave rise to a different overall payment lead. Benefits data was also updated in the FBC 2018 Lead-Lag Study to reflect the actual payment terms and frequency for each benefit category. Both of these categories used high-level assumptions in the previously approved method.

- Insurance increased by 1.7 days - the increase in Insurance expense is related to the high-level assumption used in the previously approved method whereby Insurance invoices were assumed to be paid the day before the coverage period. The actual data used in the FBC 2018 Lead-Lag Study shows a longer Payment Lag because payments were made 23 days after the coverage period began.

- Other O&M decreased by 1.7 days – the decrease was mainly because the actual data used in the FBC 2018 Lead-Lag Study shows the Payment Lag for Other O&M was 26.7 days compared to the assumed 30.4 days in the previously approved method, a decrease of 3.7 days.

135.0 Reference: SHARED SERVICES STUDY

Exhibit B-1, Sections D4.1, D4.5, pp. D-37, D-40; Exhibit B-1-1, Appendix D4, pp. 2, 12

Introduction

FortisBC states on page D-37 of the Application:

> 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 Application, FortisBC proposes to move to allocate costs, except for the Executive Management Team time, based on cost drivers (Cost Driver Approach).

135.1 Please explain why FortisBC prepared its analysis based on moving to a Cost Driver Approach to allocating shared services costs, except for Executive Management Team time, as opposed to some other approach (e.g. Massachusetts Formula).

Response:

In general, FEI believes allocating shared services costs based on cost drivers that reflect the cost causation of the individual shared service departments will result in more representative cost allocations than using general methods like the Massachusetts Formula for a collective group of departments' shared resources. The use of cost drivers has also been successfully employed and approved in past shared service allocations for FEI's former subsidiaries FEVI and FEW. The Massachusetts Formula approach is well established and generally accepted in BC and other regulatory jurisdictions and is typically applied for corporate type costs such as that for approved by the BCUC for Executive cross charges between FEI and FBC.

On page D-37 of the Application, FortisBC states "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."

Table D4-3 on page D-40 compares 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. FortisBC states, "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."

FortisBC states on page 12 of Appendix D4, "Given the difference in the allocations of the two approaches is minimal, [it] recommends adopting the Cost Driver Approach."

135.2 In a similar format to Table D4-3, please provide a comparison of the O&M Shared Services allocations between the existing Timesheet Approach and the proposed Cost Driver Approach for 2013 to 2017 Actual O&M Shared Services.

Response:

Provided below is FortisBC's approximation of the allocations using the Timesheet Approach compared to the proposed Cost Driver Approach, based on the actual labour cross charges observed from 2013 – 2017.

FortisBC identified the actual 2013 – 2017 timesheet allocations for each department and applied the cost drivers as proposed in the study. The "Differences in Approaches" column in the table below provides the total difference between the Timesheet approach used historically and the proposed Cost Driver approach.

(millions)	O&M Actual Timesheet Approach	O&M Actual Cost Driver Approach	Allocations as per Timesheet Approach	Allocations as per Cost Driver Based	Differences in Approaches
2017					
FEI	259,631	260,186	657	1,212	(555)
FBC	55,821	55,266	(657)	(1,212)	555
Total	315,452	315,452	-	-	-
2016					
FEI	259,459	260,356	31	928	(897)
FBC	55,610	54,713	(31)	(928)	897
Total	315,069	315,069	-	-	-
2015					
FEI	260,034	261,978	(97)	1,847	(1,944)
FBC	57,785	55,841	97	(1,847)	1,944
Total	317,819	317,819	-	-	-
2014					
FEI	257,788	259,620	89	1,921	(1,832)
FBC	59,723	57,890	(89)	(1,921)	1,832
Total	317,511	317,511	-	-	-
2013					
FEI	264,923	269,789	133	4,999	(4,866)
FBC	56,696	51,830	(133)	(4,999)	4,866
Total	321,619	321,619	-	-	-

Please also refer to the response to BCUC IR 1.137.1 for further details for each year.

When preparing this response, FEI noticed that the total provided for 2018 actual O&M was misstated as it included some non-regulated amounts. FEI provides a corrected view below and notes the change to the total actual O&M does not affect the results of the proposed allocation approach.

Below is corrected Table A:D4-4 from Appendix D4, and will be included in an Errata to be filed in the near future.

FORTISBC - FEI and FBC Shared Services Study Summary $000's																
	Current approach (1)						Cost driver approach (2)								Difference (3)	
Function	2018 actual (a)		Cross charges (b)		2018 actual w/ CC (c)		2018 actual (a)		Allocation (d)				2018 actual after cost driver (e)		Overall Impact	
	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Cost driver	Gas	Electric		Gas	Electric	Gas	Electric
Shared Service																
Corporate	4,560	2,040	-	-	4,560	2,040	4,560	2,040	Mass. Formula	-	-		4,560	2,040	-	-
Customer Service	44,559	6,269	389	(389)	44,948	5,880	44,559	6,269	Customers	289	(289)		44,848	5,980	(100)	100
Operations Support	17,193	3,387	(107)	107	17,086	3,494	17,193	3,387	Employees	(162)	162		17,031	3,548	(54)	54
Finance	9,698	3,795	337	(337)	10,035	3,458	9,698	3,795	Mass. Formula	412	(412)		10,110	3,383	75	(75)
Fleet Services	2	298	28	(28)	30	270	2	298	Time Estimate	0	-		2	298	(28)	28
Health & Safety	7,340	854	(60)	60	7,280	914	7,340	854	Employees	(162)	162		7,178	1,016	(103)	103
Human Resources	7,828	1,783	(95)	95	7,734	1,878	7,828	1,783	Employees	(194)	194		7,635	1,977	(99)	99
Information Systems	22,628	4,854	263	(263)	22,891	4,591	22,628	4,854	Employees	256	(256)		22,885	4,597	(6)	6
Communications & External Relations	10,493	1,574	132	(132)	10,625	1,442	10,493	1,574	Employees	26	(26)		10,520	1,547	(106)	106
Legal	1,768	486	-	-	1,768	486	1,768	486	Time Estimate	-	-		1,768	486	-	-
Risk Management	5,520	1,369	-	-	5,520	1,369	5,520	1,369	Time Estimate	-	-		5,520	1,369	-	-
Regulatory	4,961	801	(169)	169	4,793	969	4,961	801	Time Estimate	(85)	85		4,876	886	83	(83)
Shared Service Total	136,551	27,509	718	(718)	137,270	26,790	136,551	27,509		381	(381)		136,932	27,128	(338)	338
Operations	133,618	31,229	664	(664)	134,282	30,565	133,618	31,229	Time Estimate	664	(664)		134,282	30,565	-	-
TOTALS	270,169	58,738	1,382	(1,382)	271,551	57,355	270,169	58,738		1,045	(1,045)		271,214	57,693	(338)	338

Additionally, in the Shared Service section in the Application on pages D-37 through D-40 and in Appendix D4, FEI and FBC Shared Services Study, 2018 FEI actual O&M should be referenced as $271,551 thousand instead of $276,511 thousand and 2018 FEI actual O&M before cross charges should be referenced as $270,169 thousand instead of $275,129 thousand. This correction will be included in an Errata to be filed in the near future.

On page 2 of Appendix D4, FortisBC states the following:

> The Cost Driver Approach is modelled after and similar to that used successfully for services provided by FEI to FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) during the ten-year period from the time of acquisition until they were amalgamated.

135.3 Please discuss the similarities and differences between the Cost Driver Approach proposed in this Application and the approach that was used for services provided by FEI to FEVI and FEW. For any differences identified, please explain the reason for these differences.

Response:

This response discusses the similarities and differences between the proposed cost driver approach and the approach previously used between FEI to FEVI and FEW and provides reasons for the differences. Additionally, a comparison of the types of services shared in both approaches is provided including discussion of the similarities/differences in operational circumstances.

Comparison of Approaches

A comparison of the proposed Cost Driver Approach to the previously approved FEI/FEVI/FEW approach is provided below.

Similarities

1. The scope of departments included in the proposed approach are included in the scope of departments in the prior approach. The details of the scope of the department are provided later on in this response.

2. The cost drivers used in the prior approach are also used in the proposed approach.

3. The labour costs being allocated in the proposed approach are also included in the prior approach. Both approaches include base pay and fringe benefits in the labour amount.

Differences

1. Some departments included in the prior approach are out of scope for the proposed approach. The details of the scope of the department are provided later on in this response.

2. A new cost driver, Massachusetts formula, is included in the proposed approach.

3. For some of the departments in scope for both approaches, the cost driver used in the prior approach is not the same driver in the proposed approach.

4. The prior approach included all costs, Labour, Non-Labour, and Overheads in the cost to be allocated. The proposed approach only includes labour.

Reason for the Differences

1. The main reason for the differences is a result of operational circumstances that reflect the nature of each organization's need at the time.

    a. In the FEI/FEVI/FEW approach, the organizations were all gas distribution companies. FEVI/FEW were able to achieve operational level efficiencies by leveraging the resources of FEI versus individually incurring their own costs.

    b. In the proposed FEI/FBC approach, the organizations are gas distribution and electric distribution companies. Both FEI and FBC have a sustained focus on integration opportunities to share common management, technology, and support functions.

2. The Massachusetts formula has been included in the proposed approach as FEI/FBC use this approved driver to allocate executive time between the two companies and found that this driver would be suited to certain other shared departments.

3. Cost drivers are used in both approaches, but some departments in the proposed approach have a different cost driver than was used in the prior approach. Cost drivers in the proposed approach were chosen based on what best represents the cause of the underlying cost.

4. In the prior approach, all the costs were included in FEI and FEVI/FEW needed to be allocated a portion of labour, non-labour, and overheads. In the proposed approach, only labour costs are included. Overhead costs like facilities and IT support related to employees are not allocated, consistent with the current BCUC approved methodology between FEI and FBC. Any other non-labour expenses (i.e., travel costs) are directly charged to each company.

Comparison of Types of Services

The tables below summarize the scope of departments, services provided, and allocation basis included in both the prior approach and proposed approach.

FEI/FEVI/FEW Prior		
Department	**Services Provided**	**Allocation Basis**
President's Office (1)	Executive planning, development, and governance.	Customers
Distribution (1)	Gas Distribution Services	Customers and Time Estimate
Human Resources & Operations Governance	HR, and Environment Health and Safety	Customers, Employees, and Time Estimate
Marketing	Marketing, Communications, Customer Service	Customers and Time Estimate
Business & Information Technology	IT, Land, Procurement, Security services	Customers, Employees, and Time Estimate
Gas Supply & Transmission (1)	Transmission asset management and pipeline safety and integrity	Customers
Finance & Regulatory Affairs	Financial and management accounting and regulatory reporting services	Customers

(1) Departments out of scope in proposed approach as these are Gas specific operations

FEI/FBC Proposed		
Department	**Services Provided (1)**	**Allocation Basis**
Customer Service	Customer service, billing, measurement, business innovation	Customers
Operations Support	Facilities, procurement, property services	Employees
Finance	Finance, accounting, business planning, and internal audit	Mass. Formula
Health & Safety	Environmental and employee safety programs	Employees
Human Resources	Shared management and support of HR programs and services	Employees
Information Systems	Shared management and support of IT programs and services	Employees
Communications & External Relations	Customer communications, external relations with governments and First Nations	Employees
Regulatory	Shared management and support for regulatory application and filings	Time Estimate

(1) Appendix B to Appendix D4 provides full detailed descriptions by function of the services being shared between FEI and FBC.

The scope of departments in the FEI/FBC proposed approach were also included in the prior approach. The prior approach had some departments grouped together and the current approach functionalizes shared services into more specific areas. For example, the prior approach grouped HR with Health and Safety, and Finance with Regulatory. The current approach has these areas separated. Appendix D4, pages B-1 to B-6 in the Application provide detailed descriptions of the services being shared.

A majority of the costs included in the prior approach were allocated based on customers and in the proposed approach an allocation basis representing the nature of the sharing was used to allocate costs. For example, Finance was previously allocated on customers, whereas the current approach allocates on the Massachusetts formula. FortisBC believes this basis to be

more appropriate and reflective of the shared cost versus allocating based on customers. The difference in allocation basis for the departments can be seen in the tables above.

Both the prior approach and the proposed approach are based on the use of cost drivers. While there may be differences in the departments sharing services reflective of the circumstances and also differences in the choice of the cost drivers used, FortisBC believes both "cost driver" based approaches provide an allocation methodology that reasonably represents the sharing of services provided.

135.4 Please provide a detailed comparison of the similarities and differences between the types of services shared by FEI to FEVI and FEW versus FEI and FBC, including the similarities/differences in operational circumstances. For each difference identified, please explain whether the Cost Driver approach is more appropriate, less appropriate or neutral.

Response:

Please refer to the response to BCUC IR 1.135.3.

136.0 Reference: SHARED SERVICES STUDY

Exhibit B-1-1, Appendix D4, Section D3.2, p. 3

History of Sharing Resources

FortisBC states on page 3 of the Appendix D4:

> Historically…The Timesheet Approach has been appropriate given the early stages of sharing of resources between the two companies and the evolving nature of integration efforts between the Gas and Electric businesses. As the sharing of resources was continuing to evolve and not stable, continuing with a Timesheet Approach to recognize the specific circumstances of the resources being shared provided an allocation methodology that reasonably represented the sharing.

Table A:D4-1 on page 3 of Appendix D4 outlines the level of capital and O&M resources shared between FEI and FBC from 2013 to 2017 Actual which shows that the sharing of labour resources has increased in recent years as FortisBC states "integration between FBC and FEI has continued to progress:"

Table A:D4-1: Capital and O&M Resources Shared between FEI and FBC - 2013 to 2017[2]

	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals
FEI to FBC					
Labour and Travel expenses	$2,334,000	$3,302,000	$3,421,000	$3,511,000	$4,565,000
Rental of Springfield Road Office	$ 329,000	$ 324,000	$ 324,000	$ 324,000	$ 324,000
Sale of Natural Gas (Tariff Sales)	$ 10,000	$ 11,000	$ 11,000	$ 9,000	$ 14,000
Total	$2,673,000	$3,637,000	$3,756,000	$3,844,000	$4,903,000
FBC to FEI					
Labour and Travel expenses	$3,315,000	$4,498,000	$5,085,000	$5,428,000	$7,012,000
Purchase of Power (Tariff)	$ 576,000	$ 568,000	$ 733,000	$ 733,000	$ 618,000
Total	$3,891,000	$5,066,000	$5,818,000	$6,161,000	$7,630,000

Sources: BCUC Annual Reports

On page 3 of Appendix D4, FortisBC states: "Sharing of resources have grown and stabilized to a point where introducing a Cost Driver Approach will simplify the administration of cost allocations between the two Utilities while providing an allocation methodology that reasonably represents the sharing."

136.1 Please provide support for the statement that the sharing of resources has "stabilized" given that there is an increasing trend in the level of capital and O&M resources shared between FEI and FBC from 2013 to 2017 Actual.

Response:

The reference to "stabilized" is in reference to O&M related Shared Services for which FortisBC is proposing to introduce a Cost Driver approach. In recent years, 2017 and 2018, the level of O&M Shared Services between FEI and FBC has moderated. As shown in figures A:D4-2 and A:D4-3 in Appendix D4 of the MRP Application, in 2018, FEI O&M labour cross charges to FBC were approximately $2.6 million with FBC to FEI of approximately $3.9 million. For comparison, in 2017, FEI O&M labour cross charges to FBC were approximately $2.6 million with FBC to FEI of approximately $3.2 million. Resources shared between FEI and FBC for capital activities are dependent on capital projects and may vary from year to year and which the Companies will continue to use a Timesheet approach for.

While the level of O&M cross charges between FEI and FBC have moderated, FortisBC notes also that FEI and FBC have been pursuing integration opportunities and sharing of O&M related Shared Services for a number of years. As a result, FortisBC believes and anticipates that the opportunities for O&M related Shared Services have stabilized (i.e., identified areas for sharing) as all departments have integrated management, recognizing though that the Companies may identify other opportunities for sharing of resources in the future.

The appropriateness of introducing a Cost Driver approach for Shared Services at this time is corroborated in the analysis provided comparing the difference between the current Timesheet approach and the proposed Cost Driver approach, where a Cost Driver approach results in a similar net allocation for O&M related Shared Services as a Timesheet approach (i.e., difference of only approximately $0.34 million).

136.2 Please provide a revised Table A:D4-1 which shows the breakdown between capital and O&M resources shared between FEI and FBC from 2013 to 2017 Actual.

Response:

A revised summary of Table A:D4-1 with an approximate breakdown between capital and O&M resources shared between FEI and FBC from 2013 to 2017 is provided below.

FEI to FBC ($000s)					
IR Requested View	**2013**	**2014**	**2015**	**2016**	**2017**
Labour and Travel Expenses	1,836	2,390	2,775	2,743	3,586
Rental of Springfield Road Office	329	324	324	324	324
Sale of Natural Gas (Tariff Sales)	10	11	11	9	14
Total FEI to FBC: O&M	**2,175**	**2,725**	**3,110**	**3,076**	**3,924**
Labour and Travel Expenses	498	912	646	768	979
Rental of Springfield Road Office	-	-	-	-	-
Sale of Natural Gas (Tariff Sales)	-	-	-	-	-
Total FEI to FBC: Capital	**498**	**912**	**646**	**768**	**979**
Total FEI to FBC: O&M & Capital	**2,673**	**3,637**	**3,756**	**3,844**	**4,903**

FBC to FEI ($000s)					
IR Requested View	**2013**	**2014**	**2015**	**2016**	**2017**
Labour and Travel Expenses	2,314	3,441	4,149	4,684	6,113
Purchase of Power (Tariff)	576	568	733	733	618
Total FBC to FEI: O&M	**2,890**	**4,009**	**4,882**	**5,417**	**6,731**
Labour and Travel Expenses	1,001	1,057	936	744	899
Purchase of Power (Tariff)	-	-	-	-	-
Total FBC to FEI: Capital	**1,001**	**1,057**	**936**	**744**	**899**
Total FBC to FEI: O&M & Capital	**3,891**	**5,066**	**5,818**	**6,161**	**7,630**

136.3 Please confirm, or explain otherwise, that the approvals sought in this Application relate only to the allocation of shared O&M costs and not capital costs.

Response:

Confirmed.

137.0 Reference: SHARED SERVICES STUDY

Exhibit B-1, Section D4.4, p. D-39; Exhibit B-1-1, Appendix D4, p. 9

Cost Driver Approach

Table D4-2 on page D-39 of the Application shows the calculation of the allocated shared costs for 2018 Actual O&M Shared Services using the Cost Driver Approach. FortisBC states that the Shared Resource Pool for 2018 is $32.8 million between FEI and FBC.[149]

137.1 In a similar format to Table D4-2, please provide the calculation of the allocated shared costs for 2013 to 2017 Actual O&M Shared Service using the Cost Driver Approach.

Response:

Tables that provide the calculation of allocated shared costs for 2013 to 2017 for the Shared Service departments are provided below.

To provide this data, FEI analysed historical cross charge records to identify the FTEs providing sharing services, analyzed records to compute the identified shared costs, and updated allocation drivers with the respective year's values.

Function	2017 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	76.4%	23.6%	-	-	-	-	-
Customer Service	**8,076**	**1,212**	**9,288**	Customers	88.0%	12.0%	**8,175**	**1,113**	**9,288**	**99**	**(99)**
Operations Support	**972**	**167**	**1,140**	Employees	76.6%	23.4%	**873**	**267**	**1,140**	**(99)**	**99**
Finance	**1,428**	**1,090**	**2,518**	Mass. Formula	76.4%	23.6%	**1,924**	**594**	**2,518**	**496**	**(496)**
Fleet Services	**312**	**431**	**743**	Time Estimate	55.5%	44.5%	**412**	**331**	**743**	**100**	**(100)**
Health & Safety	**3,238**	**991**	**4,229**	Employees	76.6%	23.4%	**3,240**	**989**	**4,229**	**2**	**(2)**
Human Resources	**3,829**	**1,180**	**5,009**	Employees	76.6%	23.4%	**3,838**	**1,171**	**5,009**	**9**	**(9)**
Information Systems	**373**	**781**	**1,154**	Employees	76.6%	23.4%	**884**	**270**	**1,154**	**511**	**(511)**
Communications & External Relations	**2,070**	**921**	**2,991**	Employees	76.6%	23.4%	**2,292**	**699**	**2,991**	**222**	**(222)**
Regulatory	**1,480**	**175**	**1,655**	Time Estimate	81.7%	18.3%	**1,352**	**303**	**1,655**	**(128)**	**128**
Shared Service Total	**21,778**	**6,948**	**28,726**				**22,990**	**5,736**	**28,726**	**1,212**	**(1,212)**

[149] The same table is provided in Table A:D4-3 on page 9 of Appendix D4.

Function	2016 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	76.4%	23.6%	-	-	-	-	-
Customer Service	**7,575**	**1,300**	**8,875**	Customers	88.0%	12.0%	**7,814**	**1,061**	**8,875**	**239**	**(239)**
Operations Support	**1,219**	**162**	**1,381**	Employees	76.2%	23.8%	**1,052**	**329**	**1,381**	**(167)**	**167**
Finance	**389**	**306**	**695**	Mass. Formula	76.4%	23.6%	**531**	**164**	**695**	**142**	**(142)**
Fleet Services	-	**292**	**292**	Time Estimate	38.7%	61.3%	**113**	**179**	**292**	**113**	**(113)**
Health & Safety	**1,928**	**998**	**2,926**	Employees	76.2%	23.8%	**2,228**	**698**	**2,926**	**300**	**(300)**
Human Resources	**3,067**	**953**	**4,020**	Employees	76.2%	23.8%	**3,061**	**959**	**4,020**	**(6)**	**6**
Information Systems	**559**	**684**	**1,243**	Employees	76.2%	23.8%	**947**	**296**	**1,243**	**388**	**(388)**
Communications & External Relations	**2,146**	**830**	**2,976**	Employees	76.2%	23.8%	**2,266**	**710**	**2,976**	**120**	**(120)**
Regulatory	**998**	-	**998**	Time Estimate	79.8%	20.2%	**796**	**202**	**998**	**(202)**	**202**
Shared Service Total	**17,882**	**5,525**	**23,407**				**18,809**	**4,597**	**23,407**	**928**	**(928)**

1

Function	2015 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	76.0%	24.1%	-	-	-	-	-
Customer Service	**973**	**1,304**	**2,277**	Customers	88.0%	12.0%	**2,004**	**273**	**2,277**	**1,031**	**(1,031)**
Operations Support	**1,381**	**165**	**1,546**	Employees	75.2%	24.8%	**1,163**	**383**	**1,546**	**(218)**	**218**
Finance	**134**	**195**	**329**	Mass. Formula	76.0%	24.1%	**250**	**79**	**329**	**116**	**(116)**
Fleet Services	-	-	-	Time Estimate	0.0%	0.0%	-	-	-	-	-
Health & Safety	**925**	**978**	**1,903**	Employees	75.2%	24.8%	**1,432**	**471**	**1,903**	**507**	**(507)**
Human Resources	**2,316**	**934**	**3,250**	Employees	75.2%	24.8%	**2,445**	**805**	**3,250**	**129**	**(129)**
Information Systems	**574**	**508**	**1,082**	Employees	75.2%	24.8%	**814**	**268**	**1,082**	**240**	**(240)**
Communications & External Relations	**1,462**	**814**	**2,276**	Employees	75.2%	24.8%	**1,712**	**564**	**2,276**	**250**	**(250)**
Regulatory	**1,275**	-	**1,275**	Time Estimate	83.7%	16.3%	**1,067**	**208**	**1,275**	**(208)**	**208**
Shared Service Total	**9,040**	**4,898**	**13,938**				**10,886**	**3,051**	**13,938**	**1,847**	**(1,847)**

2

Function	2014 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	76.8%	23.2%	-	-	-	-	-
Customer Service	**1,154**	**543**	**1,697**	Customers	88.1%	11.9%	**1,494**	**203**	**1,697**	**340**	**(340)**
Operations Support	**1,192**	**119**	**1,311**	Employees	77.0%	23.0%	**1,010**	**301**	**1,311**	**(182)**	**182**
Finance	**120**	**828**	**948**	Mass. Formula	76.8%	23.2%	**728**	**220**	**948**	**608**	**(608)**
Fleet Services	-	-	-	Time Estimate	0.0%	0.0%	-	-	-	-	-
Health & Safety	**752**	**958**	**1,710**	Employees	77.0%	23.0%	**1,317**	**393**	**1,710**	**565**	**(565)**
Human Resources	**2,270**	**915**	**3,185**	Employees	77.0%	23.0%	**2,453**	**732**	**3,185**	**183**	**(183)**
Information Systems	**485**	**366**	**851**	Employees	77.0%	23.0%	**656**	**195**	**851**	**171**	**(171)**
Communications & External Relations	**1,617**	**798**	**2,415**	Employees	77.0%	23.0%	**1,860**	**555**	**2,415**	**243**	**(243)**
Regulatory	**599**	-	**599**	Time Estimate	98.7%	1.3%	**590**	**8**	**599**	**(8)**	**8**
Shared Service Total	**8,189**	**4,527**	**12,716**				**10,109**	**2,606**	**12,716**	**1,921**	**(1,921)**

3

Function	2013 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	76.8%	23.2%	-	-	-	-	-
Customer Service	**987**	**2,112**	**3,099**	Customers	88.1%	11.9%	**2,729**	**370**	**3,099**	**1,742**	**(1,742)**
Operations Support	**170**	-	**170**	Employees	80.0%	20.0%	**136**	**34**	**170**	**(34)**	**34**
Finance	-	**1,385**	**1,385**	Mass. Formula	76.8%	23.2%	**1,064**	**321**	**1,385**	**1,064**	**(1,064)**
Fleet Services	-	-	-	Time Estimate	0.0%	0.0%	-	-	-	-	-
Health & Safety	**675**	**939**	**1,614**	Employees	80.0%	20.0%	**1,290**	**324**	**1,614**	**615**	**(615)**
Human Resources	**2,224**	**897**	**3,121**	Employees	80.0%	20.0%	**2,495**	**626**	**3,121**	**271**	**(271)**
Information Systems	**345**	**1,194**	**1,539**	Employees	80.0%	20.0%	**1,230**	**309**	**1,539**	**885**	**(885)**
Communications & External Relations	**1,017**	**782**	**1,799**	Employees	80.0%	20.0%	**1,438**	**361**	**1,799**	**421**	**(421)**
Regulatory	**401**	**848**	**1,249**	Time Estimate	34.8%	65.2%	**435**	**815**	**1,249**	**34**	**(34)**
Shared Service Total	**5,819**	**8,157**	**13,976**				**10,818**	**3,158**	**13,976**	**4,999**	**(4,999)**

4

(1) Identified Shared Costs = The adjusted gross salaries for the FTE providing service to both FEI and FBC. Adjusted gross salaries is gross salary less non FEI/FBC time.
(2) Allocation Basis as defined in the Shared Service Study, updated for values for respective year
(3) Allocated Shared Costs = Total Identified Shared Cost (1) multiplied by Allocation Basis (2)
5 (4) Difference is the allocated shared cost less the amount that was shared. This amount is what is compared against cross charges from the timesheet approach.

6

138.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section D5.1, p. D-41

Introduction

On page D-41 of the Application, FortisBC states the following:

> In this Application, FortisBC is requesting approval of the methodologies of allocating common corporate service costs from FI and FHI to FEI and FBC… 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.

138.1 Please discuss what prompted FortisBC to review the methodologies of allocating common corporate services costs from FI and FHI to FEI and FBC and to engage KPMG to provide an independent assessment.

Response:

For the 2014-2018 PBR Application, a 2013 Corporate Service Study (2013 CS Study) was prepared for FI and FHI costs allocated to FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC Energy (Whistler) Inc. (FEW). FBC was excluded from the scope of the 2013 CS Study and at that time, Aitken Creek was not yet acquired.

As described in Section D5.2 of the MRP Application, there have been several changes that prompted a review of the corporate services methodology. FEVI and FEW amalgamated with FEI and therefore the allocations from the 2013 CS Study between the three entities are no longer required during the 2020-2024 MRP period. In addition, the organization has placed effort into integrating the FEI and FBC departmental functions, which has also aligned corporate services provided by FHI. Therefore, the inclusion of FBC in an updated corporate services model, instead of direct charging as was performed during the Current PBR Plan period, was considered. Lastly, ACGS was acquired as an operating subsidiary of FHI in 2016, and ACGS utilizes certain of the same corporate services provided by FHI as FEI and FBC. As a result, FortisBC believes the previous methodologies used for allocating corporate service costs from FI and FHI to FEI and FBC required further analysis to establish an updated methodology for 2020 and beyond.

By introducing ACGS and FBC into a formula sharing methodology with FEI for corporate services, combined with the amalgamation of the gas utilities, FortisBC sought external expertise to corroborate its updated and proposed methodology. FortisBC engaged KPMG to provide independent assessments in 2009 and in the 2013 CS Study, and as a result the firm is familiar with current methodologies within the industry, past organization structures, and regulatory requirements. KPMG has the experience and expertise to provide an independent and appropriate review of the assumptions utilized in FortisBC's 2018 Corporate Service Study.

138.1.1 What are FortisBC's policies and practices with respect to regular review/update of its allocation methodologies?

Response:

There is no set policy or timeline for review of corporate service models. However, as discussed in BCUC IR 1.138.1, FortisBC initiated the review/update of its allocation methodologies due to amalgamation of the FortisBC Gas Utilities, the acquisition of ACGS as an operating subsidiary of FHI, and further integration of FEI and FBC departmental functions.

139.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section D5.1, D5.2, pp. D-41 – D-43, D-49

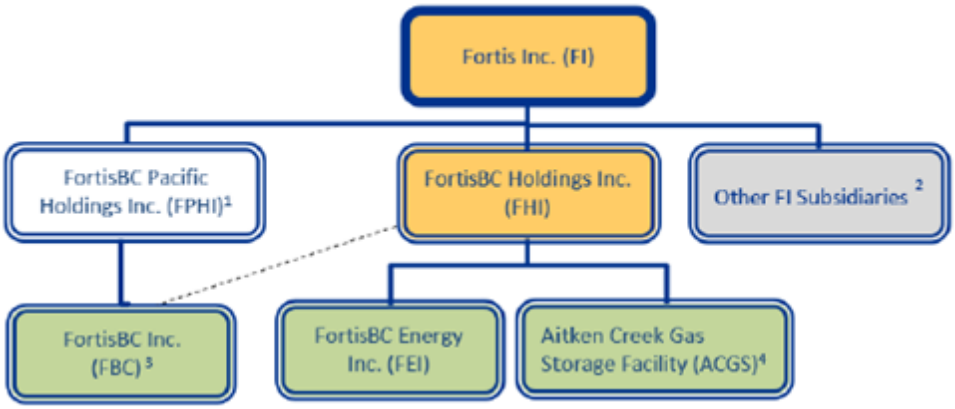
Review of Changes Since 2013 Corporate Services Study

FortisBC states the following on page D-41 of the Application:

> 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.

Figure D5-1 on page D-41 shows the 2018 Corporate Services Study Organizational Chart as follows:

Figure D5-1: 2018 Corporate Services Study Organizational Chart



On pages D-42 to D-43 of the Application, FortisBC states that one of the changes included in the 2018 Corporate Services Study as compared to the 2013 Corporate Services Study is that ACGS and FBC have been added to the sharing methodology of FI and FHI corporate services costs. FI and FHI have previously been directly charging ACGS and FBC for the corporate services provided.

On page D-43 of the Application, FortisBC further states:

- 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.

FortisBC proposes on page D-49 that the eligible pool of FHI corporate service costs are allocated to FEI, FBC and ACGS using the Massachusetts Formula.

139.1 Please provide in a table format the total 2014 to 2018 Actual corporate services costs charged directly to FBC by FI and FHI, respectively.

Response:

The 2014 to 2018 actual corporate services costs charged directly to FBC by FI and FHI are provided below:

Corporate Services Costs Charged to FBC

Actuals	2014	2015	2016	2017	2018
FBC portion of FI and FHI Corporate Services Costs	2,624	2,080	2,582	2,682	2,638

139.1.1 Please discuss the extent to which adding FBC to the pool of FI corporate services cost charged to FHI impacts FEI and ACGS upon the subsequent allocation of FHI corporate services costs to FBC, FEI and ACGS (i.e. will increasing the pool of FI corporate services costs result in a higher allocation (dollar amount) of FHI corporate services cost to either FEI or ACGS than before?) Please provide a numerical example to show the impact.

Response:

The following example utilizes 2018 financial data to demonstrate how the proposed allocation methodology could have an effect on the FI corporate services allocated to FBC, FEI and ACGS. The example below uses the Massachusetts formula percentages from page 23 of Appendix D5 and are estimated at a point in time. As a result of using these assumptions, the actual effect for the 2020 MRP may not be the same as the example below.

	Current Allocation Methodology			
	Eligible Portion for Allocation to FEI, ACGS, & FBC *	**FEI**	**ACGS**	**FBC**
		($000)		
FHI Portion of 2018 FI Costs	5,570	5,205	366	
FBC Portion of 2018 FI Costs	1,640			1,640
FortisBC Subsidiaries of 2018 FI Costs	7,210	5,205	366	1,640

	Proposed Allocation Methodology			
	Eligible Portion for Allocation to FEI, ACGS, & FBC *	**FEI**	**ACGS**	**FBC**
		($000)		
Massachusetts Formula		73%	5%	22%
FortisBC Subsidiaries of 2018 FI Costs	7,210	5,228	370	1,612
Variance		24	4	(28)

* *The Eligible Portion for Allocation to FEI, ACGS, & FBC is the total FI corporate service costs per Table D5-2 on Page D-47 in the Application, excluding certain costs that are specific to FHI, as described on lines 16-21 on page D-49 of the MRP Application.*

Using the data provided above, adding corporate service costs charged to FBC into the pool of FI corporate service costs to be charged to the FortisBC subsidiaries by way of the FHI management fee, would be expected to increase FEI and ACGS allocated costs by $24 thousand and $4 thousand, respectively. Consequently, the FBC portion would decrease by $28 thousand.

139.1.2 Please provide a side-by-side comparison of the total Actual corporate services costs charged directly by FI and FHI to FBC (as provided in the IR above) and the corporate services costs allocated to FBC using the proposed cost sharing methodology had it been in place for 2014 to 2018.

Response:

A comparison of actual FI and FHI corporate service costs charged to FBC during 2014 to 2018 using the current methodology to the proposed methodology is provided below.

Comparison of Corporate Services Costs in FBC ($000s)

Corporate Services Costs Charged to FBC					
Actuals	**2014**	**2015**	**2016**	**2017**	**2018**
FBC portion of FI and FHI Corporate Services Costs	2,624	2,080	2,582	2,682	2,638
Proposed Allocation Methodology	**2014**	**2015**	**2016**	**2017**	**2018**
FBC portion of FI and FHI Corporate Services Costs	3,643	3,526	3,756	3,563	3,508

While the requested historical comparison has been prepared comparing the methodologies, the comparison is misleading for two main reasons.

The FortisBC Utilities have recommended the proposed sharing methodology due to the integration that exists between FEI and FBC at the end of the Current PBR Plan term that did not exist to the same degree at the beginning in 2014. As noted in the response to BCUC IR 1.138.1, FortisBC has placed effort into the integration of the FEI and FBC departmental functions during the 2014-2019 PBR Plan period, which has also aligned corporate services provided by FHI. As alignment has increased so has the level of support provided. Therefore, applying the proposed methodology to historical periods overstates the level of FHI corporate services that would be allocated to FBC.

As noted in Table D5-4, on page D-51 of the Application, along with the proposed methodology there will be certain FBC O&M costs, estimated at approximately $315 thousand in 2019/2020, that would be included in the FHI corporate services pool of costs to ensure appropriate sharing. These actual FBC O&M costs cannot be reasonably estimated in earlier years due to a lower level of integration between FEI and FBC. In the table above, those shared costs have not been identified and reallocated from FBC O&M into the FHI corporate services pool of costs for 2014 to 2018. As such, the variances in the table above are overstating the impact that would have occurred on FBC O&M.

For these reasons, the historical comparison in the above table isn't a meaningful comparison. Rather the expected impact of the proposed methodology is outlined in the revised Table C2-14 included in the response to BCUC IR 1.34.1. Similarly, the overall impact for 2020 is expected to be approximately $383 thousand, as shown in Table D5-4 of the Application.

139.2 Please provide in a table format the actual corporate services costs charged directly to ACGS by FI and FHI, respectively, since the acquisition of ACGS in 2016.

Response:

The corporate services costs charged directly to ACGS by FI and FHI since acquisition in April 2016 are provided below.

FI and FHI Corporate Services Costs Charged to ACGS

Corporate Services Costs Charged to ACGS Actuals ($000)	2016	2017	2018
ACGS portion of FI and FHI Corporate Services Costs	200	605	667

The actual 2016 corporate services costs charged to ACGS were lower than subsequent years due to the acquisition occurring part way through the year in 2016. In addition, during the first year of integrating ACGS into the Fortis group, certain acquisition related costs, which are different than corporate service related costs, were absorbed by FHI but were not charged to ACGS or FEI. For further clarification, there were no FI or FHI corporate services relating to ACGS that were charged to FEI.

139.2.1 Please provide a side-by-side comparison of the Actual corporate services costs charged directly by FI and FHI to ACGS (as provided in the IR above) and the corporate services costs allocated to ACGS using the proposed cost sharing methodology had it been in place for 2014 to 2018.

Response:

A comparison of actual corporate services costs charged to ACGS since acquisition in April 2016, and using the proposed methodology for the same period, is provided in the table below.

Comparison of FI and FHI Corporate Services Costs in ACGS ($000s)

Corporate Services Costs Charged to ACGS			
Actuals ($000)	**2016**	**2017**	**2018**
ACGS portion of FI and FHI Corporate Services Costs	200	605	667
Proposed Allocation Methodology ($000)	**2016**	**2017**	**2018**
ACGS portion of FI and FHI Corporate Services Costs	200	817	804

The proposed cost sharing methodology for 2016 has not been changed because, in the year of acquisition, corporate services would be direct charged using the same approach. This is due to the level of corporate services required in an entity's first year being different than its requirements once fully incorporated into the Fortis group and, therefore, is better suited to specific identification and allocation rather than under a formula approach that is rebased part way through a year. Also, as noted on page D-42 of the Application, a Massachusetts Formula is only applied once a business is stable and operating for a period of time, which wouldn't be the case in the year of acquisition.

While the requested historical comparison has been prepared using both methodologies, the comparison is misleading. FortisBC has recommended the proposed sharing methodology due to continued integration of the group of Fortis companies in BC that did not exist to the same degree in the period soon after ACGS was acquired. As alignment has increased, so has the level of support provided. Therefore, applying the proposed methodology to historical periods overstates the level of FI and FHI corporate services that would be allocated to ACGS.

139.3 Please provide in a table format the actual FI and FHI corporate services costs allocated to FEI (by way of the FHI management fee) for 2014 to 2018.

Response:

The 2014 to 2018 Actual corporate services costs charged directly to FEI by FI and FHI are provided below:

Corporate Services Costs Charged to FEI

Corporate Services Costs Charged to FEI					
Actuals ($000)	**2014**	**2015**	**2016**	**2017**	**2018**
FEI portion of FI and FHI Corporate Services Costs	12,846	12,896	13,368	12,647	12,383

The FHI management fee allocated to FEI has decreased from 2016 to 2018 due to certain labour and non-labour costs which reside in FHI up to 2016 but which were incurred directly in FEI and removed from the FHI management fee after 2016.

139.3.1 Please provide a side-by-side comparison of the total Actual FHI Management Fees charged to FEI (as provided in the IR above) and the corporate services costs allocated to FEI using the proposed cost sharing methodology had it been in place for 2014 to 2018.

Response:

A comparison of actual FI and FHI corporate service costs charged to FEI during 2014 to 2018 using the current methodology, comparing to the proposed methodology for the same period, is provided below.

Comparison of Corporate Services Costs in FEI ($000s)

Corporate Services Costs Charged to FEI					
Actuals ($000)	**2014**	**2015**	**2016**	**2017**	**2018**
FEI portion of FI and FHI Corporate Services Costs	12,846	12,896	13,368	12,647	12,383
Proposed Allocation Methodology ($000)	**2014**	**2015**	**2016**	**2017**	**2018**
FEI portion of FI and FHI Corporate Services Costs	11,827	11,450	12,347	11,555	11,376

While the requested historical comparison has been prepared comparing the methodologies, the comparison is misleading for the following reasons (please also refer to the response to BCUC IR 1.139.1.2 where the same is noted for FBC).

The FortisBC Utilities have recommended the proposed methodology due to the integration that exists between FEI and FBC at the end of the Current PBR Plan term that did not exist to the same degree at the beginning in 2014. As noted in the response to BCUC IR 1.138.1, FortisBC

has placed effort into the integration of FEI and FBC departmental functions during the Current PBR Plan, which has also aligned corporate services provided by FHI. As alignment has increased, so has the level of support provided. Therefore, applying the proposed methodology to historical periods overstates the level of FHI corporate services provided to FBC, and consequently understates the level of FHI corporate services provided to FEI.

As noted in Table D5-4 on page D-51 of the Application, along with the proposed methodology there will be certain FBC O&M costs, estimated at approximately $315 thousand in 2019/2020, that would be included in the FHI corporate services pool of costs to ensure appropriate sharing. These FBC O&M costs cannot be reasonably estimated in prior years and, therefore, have not been identified and reallocated from FBC O&M into FHI annually during the periods of 2014 to 2018. Therefore, the variances in the table above are understating the impact on FEI O&M.

Included in the response to BCUC IR 1.24.1 is an updated Table C2-1 which incorporates the effect of the proposed methodology. The overall impact for 2020 is expected to be approximately $122 thousand, as shown in Table D5-4 on page D-51 of the Application.

140.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section D5.4, p. D-46; Exhibit B-1-1, Appendix D5, Section 5.4, p. 13; FEI PBR Application proceeding, Exhibit B-1-1, Appendix F2, Section 5.6, p. 15

FI Corporate Services Allocation Methodology

On page D-46 of the Application, FortisBC states: "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 FI allocator formula is shown on page D-46 of the Application 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)

KPMG states the following on page 13 of Appendix D5:

> Following a review conducted by an external consultant in 2017, Fortis uses controllable operating costs as well as total assets (excluding goodwill) to determine the allocation of the general cost pool. The use of multiple factors for general cost allocation is a balanced methodology. The methodology is consistent with the approach used by many utilities, and based on our research is favoured by many regulators.

140.1 Please explain what "FortisBC Subsidiaries" and "FI" costs are included in controllable costs in the FI allocator formula and why.

Response:

The FI controllable costs are generally the aggregate of O&M costs (excluding FI corporate service costs) from each of the FI Subsidiaries, which includes the FortisBC Subsidiaries. For the purposes of this allocation exercise, the characterization of O&M as "controllable costs" is not intended to distinguish between O&M that is subject to the account of the shareholder, earnings sharing or flow through for regulatory purposes. Rather, it is intended to assist in differentiating from other income statement costs such as property tax, interest and tax which are less controllable in nature and can vary significantly by jurisdiction and subsidiary. The main driver to allocate corporate services continues to be the asset value. The introduction of "controllable costs" is a further refinement to the corporate services cost allocation as it recognizes that each subsidiary operates in a substantially autonomous manner and that the level of O&M costs at each of the FI Subsidiaries is an indicator of the level of FI corporate

services provided to each of the subsidiaries. Using these two factors is simple to administer, and considers both balance sheet and income statement elements for the FI subsidiaries.

140.2 Please provide further details regarding the "review conducted by an external consultant in 2017" which is referenced in the preamble above (e.g. purpose, scope, approach/methodology, key findings).

Response:

In 2017, after acquiring three U.S. utilities over the previous several years, FI revisited the allocation methodology of its corporate services provided to its subsidiaries. FI continues to allocate its corporate services utilizing asset values as the primary allocation factor, while also using controllable costs as an additional allocation factor. The rationale for utilizing these two allocation factors is described further in the response to BCUC IR 1.140.1. The appropriateness of these drivers was corroborated by KPMG, who performed an independent review of the FI allocation methodology and the reasonableness of the allocators, as described in Appendix D5 of the Application.

140.3 Please provide the names of utilities using "multiple factors for general cost allocation." Are the factors selected by these utilities the same as the factors proposed by FortisBC (i.e. total assets (excluding goodwill) and controllable operating costs)? To the extent that the factors differ, please elaborate on the reasons why FortisBC selected the proposed factors.

Response:

As identified in Appendix D5, the use of multiple factors is a balanced methodology used by many utilities, a selection of which is provided below based on publicly available, non-confidential information. In most cases, more than one cost allocation factor is used, often combining balance sheet (assets) and income statement (expense) elements.

Company	Allocators
Dominion Resources Services Inc.	Total O&M
Southern Company Services Inc.	Fixed Assets, Operating Expense, and Operating Revenue
WEC Business Services Inc.	Assets (excl Goodwill, Hedge, and Non-ordinary Assets) and O&M
National Grid USA Service Company	Net Margin, Net Plant, and Net O&M
Liberty Utilities (Canada) Corp	Utility Plant, Customer Count, Labour and Non-Labour Expense
Algonquin Power & Utilities Corp.	Utility Plant, Customer Count, Labour and Non-Labour Expense
Duke Energy Business Services LLC	Gross Margin, Labour Expense and PP&E
Hydro One	Revenue, Assets
EPCOR Distribution & Transmission Inc.	Revenue, Assets, Headcount
Enbridge Inc.	Capital Employed, Corporate FTE
Direct Energy Regulated Services	Gross Margin

FI uses two cost-allocation factors, combining a balance sheet and income statement approach of (1) total assets (excluding goodwill) and (2) controllable operating expenses (which is generally O&M). Utilizing assets provides a basis of relative size of each operating subsidiary and also represents a level of shareholder investment required of the operating subsidiaries supported by FI. Utilizing controllable operating expenses recognizes that each subsidiary operates in a substantially autonomous manner and directly manages certain costs, which represents a proxy for levels of activity supported by FI.

140.4 Please summarize the reasons why “many regulators” favour the multiple factors approach and provide supporting references, if available.

Response:

As discussed in Section 5.4, on Page 13 of Appendix D5, KPMG states:

- The use of multiple factors for general cost allocation is a balanced methodology.
- Using multiple factors recognizes that there is no one perfect allocator, and mitigates the inherent risk associated with using one measure for calculating general cost allocations.
- The use of Assets and Operating Expenses also represents a strong proxy for activity levels at the subsidiaries that are supported by the parent companies.

In addition, there are examples of other utilities listed in the response to BCUC IR 1.140.3 which demonstrate widespread regulator support for using multiple factors to allocate corporate services.

In the FEI PBR Application, KPMG stated in Appendix F2 (2013 Corporate Services Study), page 15 that once the FI cost allocation pool has been determined:

> FI uses proportionate total assets as the allocator to allocate its recoverable operating costs to its subsidiaries based on the rationale that total assets are most closely related to the net investment required of FI in each subsidiary... [*Emphasis Added*]

140.5 Please explain why FortisBC proposes to amend the FI allocator formula such that it is based on assets (excluding goodwill) and controllable costs, whereas the previously approved formula was based on total assets. Please include in the discussion the rationale for now also excluding goodwill from total assets and the impact of this proposed change.

Response:

The dollar impact of excluding goodwill from total assets, as an allocator of FI corporate services, cannot be readily quantified as each of the FI operating subsidiaries will have a different proportion of goodwill, if any. In addition, there were two new FI operating subsidiaries acquired since the 2013 Corporate Services Study, both of which also have different relative proportions of goodwill to asset value.

While total assets continues to be an appropriate allocator of corporate services and remains a primary driver with a weighting of 75 percent per Table D5-1 on page D-46 of the Application, the exclusion of goodwill and the introduction of controllable costs as a factor continues to refine how FI's corporate services are allocated to its subsidiaries. The rationale for making this refinement to the allocator methodology is discussed in the response to BCUC IR 1.140.2 and the benefits of using a multi-factor cost-allocation methodology are discussed in the response to BCUC IR 1.140.4.

US GAAP broadly defines goodwill as the excess of purchase price over the fair value of net identifiable assets acquired in a business. For external reporting purposes, these goodwill amounts are generally pushed down to each subsidiary. As discussed in the response to BCUC IR 1.141.3, since the 2013 Corporate Services Study, FI has acquired a significant portion of its assets through the acquisitions of UNS Energy Corporation and ITC Holdings, which have

resulted in a significant increase in both total assets and goodwill. As a result, certain subsidiaries have a greater proportion of goodwill than others. However, in each case the goodwill doesn't represent an operating regulated asset at the subsidiary that is tied to corporate service costs incurred by the parent company. Therefore, in order to represent an appropriate amount of asset activity level, the goodwill is excluded from total assets for FI corporate services allocation purposes.

141.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section D5.4, pp. D-46 – D-47; Exhibit B-1-1, Appendix D5, Section 5.4,

p. 13; FEI PBR Application proceeding, Exhibit B-1-1, Appendix F2, Section 5.7, p. 15

FHI Proportion of FI Total Assets and Controllable Costs

FortisBC shows in Table D5-1 on page D-46 of the Application that, after applying the allocator formula, the percentage allocation of FI corporate services to FortisBC Subsidiaries is 21.4 percent:

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%**

KPMG explains on page 13 of Appendix D5 that the 21.4 percent is "FHI's portion of FI recoverable cost is calculated based on the weighted average of the FortisBC gas and electric asset allocation (excluding goodwill), and controllable cost allocation…"

In the FEI PBR Application, KPMG stated the following on page 15 of Appendix F2 (2013 Corporate Services Study):

> ... Based on December 31, 2013 forecast asset values in FI's 2013-2017 Business Plan, FHI represents 41.94% of the utility asset base to which costs will be allocated. [*Emphasis Added*]

141.1 Please clarify whether ACGS was included in the calculation of FHI's portion of FI recoverable costs. If not, please explain why not.

Response:

FHI acquired ACGS in 2016. As a result, ACGS was not included in the 41.94 percent described in 2013 CS Study which was an estimate of FI corporate service allocations only at that point in time. However, ACGS has been included in the FortisBC Subsidiaries' 21.4 percent portion of FI recoverable costs, shown in Table D5-1 on page D-46 of the Application.

141.2 Please provide the calculation of the 21.4 percent allocation of FI corporate services costs to FHI, showing each FortisBC subsidiary's contribution to the overall percent allocation.

Response:

The 21.4 percent allocation of FI corporate services costs to the FortisBC Subsidiaries is provided by FI. It is based on two allocation factors: assets and controllable operating costs.

- The asset allocation of 21.9 percent is based on FHI (which includes FEI and ACGS) and FBC's assets as a proportion of the total assets of the FI subsidiaries (excluding goodwill).

- The controllable cost allocation of 19.9 percent is based on FHI (which includes FEI and ACGS) and FBC's controllable costs as a proportion of the total controllable costs of the FI subsidiaries.

FI Corporate Services 2018 Allocation

2018 ($ million)	FHI	FBC	FortisBC Subsidiaries' Portion	Percentage	Weighting	FortisBC Subsidiaries' Allocation
Asset (exl. Goodwill)	6,105	1,989	8,094	21.9%	75%	16.4%
Controllable Cost	279	56	334	19.9%	25%	5.0%
Overall Allocation						**21.4%**

141.3 Please explain the difference in the overall allocation of FI corporate services costs to FHI between the 2018 Corporate Services Study (i.e. 21.4 percent) and the 2013 Corporate Services Study (i.e. 41.94 percent). Why is it appropriate that a lower percentage of total FI corporate services costs is allocated to FHI compared to before?

Response:

The decrease in the percentage of FI corporate services allocated to FortisBC Subsidiaries is primarily due to the FortisBC Subsidiaries representing a smaller proportion of the total FI group

of companies' assets at the time of preparing the 2018 CS Study as compared to the 2013 CS Study.

As compared to the 2013 CS Study, the FI corporate services allocation percentage to the FortisBC Subsidiaries decreased primarily due to increased assets at FI resulting from FI's regulated utility acquisitions in the United States, which included UNS Energy Corporation in Arizona in 2014 and multi-state electric transmission utility ITC Holdings Corp. in 2016.

With these FI acquisitions, as well as investment growth at other FI utility subsidiaries, FI's total assets (excluding goodwill) increased significantly from 2013 to 2018. Although the FortisBC Subsidiaries asset base grew during that period, the greater rate of increase in FI total assets (excluding goodwill) since the 2013 CS Study caused a decrease in the FortisBC Subsidiaries' proportionate allocation of FI corporate service costs. Accordingly, FEI and FBC customers receive the benefit of economies of scale because FI corporate service costs are now allocated across a much larger consolidated FI group.

In addition, the FI corporate services allocation to the FortisBC subsidiaries also decreased slightly due to the introduction of the controllable cost factor, which represented 19.9 percent compared to the asset factor of 21.9 percent, in the determination of the overall allocation percentage of 21.4 percent.

On page D-47 of the Application, FortisBC states the following:

> 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.

141.4 Please provide the calculation of the 66.9 percent allocation of the EVP, Western Utility Operations to FHI, showing each FortisBC subsidiary's and FortisAlberta's contribution to the overall percent allocation.

Response:

The 66.9 percent allocation of EVP, Western Utility Operations to the FortisBC Subsidiaries is provided by FI. It is based on two allocation factors: assets and controllable costs.

- The asset allocation of 65.7 percent is based on FHI (which includes FEI and ACGS) and FBC's assets as a proportion of the total assets of FortisBC Subsidiaries and FortisAlberta (excluding goodwill).

- The controllable cost allocation of 70.7 percent is based on FHI (which includes FEI and ACGS) and FBC's controllable costs as a proportion of the total controllable costs of FortisBC Subsidiaries and FortisAlberta.

The remainder of the eligible EVP, Western Utility Operations costs are allocated to FortisAlberta at 33.1 percent.

EVP West 2018 Allocation

2018 ($ million)	FHI	FBC	FortisBC Subsidiaries' Portion	Percentage	Weighting	FortisBC Subsidiaries' Allocation
Asset (exl. Goodwill)	6,105	1,989	8,094	65.7%	75%	49.2%
Controllable Cost	279	56	334	70.7%	25%	17.7%
Overall Allocation						**66.9%**

141.5 Please explain whether the EVP, Western Utility Operations is a new position.

Response:

The EVP, Western Utility Operations was a position introduced in 2014 and therefore, was not discussed in the 2013 Corporate Services Study. However, costs associated with this position have formed part of the FI corporate services allocated to the FortisBC Subsidiaries since 2014. The position forms part of the executive functional area of FI, supporting the business activities of its subsidiaries.

142.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section D5.4, p. D-47

FHI Proportion of FI Recoverable Costs

Table D5-2 on page D-47 of the Application shows that $8,771,431 would be charged from FI to FHI to support the FortisBC subsidiaries "had the described allocation methodology for FI corporate services been used in 2018[150]":

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

142.1 Please provide a revised version of Table D5-2 based on 2018 Actual FI corporate services costs eligible for allocation which shows the amount that would be charged from FI to FHI under the proposed allocation methodology for FI corporate services. Please add an additional column to the table that shows 2018 Actual FI corporate services cost amounts.

Response:

The revised version of Table D5-2 based on 2018 Actual FI corporate services costs eligible for allocation is provided below.

[150] This is based on using the 2018 budgeted O&M costs of FI, as noted in Appendix D5 (page 4 and Table 5.5 and 5.6).

FI Recoverable Cost Categories	% Allocated to FortisBC Subsidiaries	FortisBC Subsidiaries Portion of FI Costs 2018 ($) Budget	FortisBC Subsidiaries Portion of FI Costs 2018 ($) Actual
Salaries (Excl EVPs, Western & Eastern Utility Ops)	21.40%	$ 3,993,593	$4,571,000
Salary (EVP, Western Utility Operations) *	66.90%	388,923	
Directors' fees and costs	21.40%	726,480	734,000
Trustees and DRIP administration	21.40%	128,109	133,000
Consulting	21.40%	485,009	505,000
Legal	21.40%	703,729	438,000
Audit	21.40%	291,306	367,000
Listing and filing	21.40%	312,094	254,000
Annual meeting and report	21.40%	206,915	229,000
Other fees	21.40%	91,373	54,000
Insurance	21.40%	223,172	225,000
Office related	21.40%	666,432	586,000
Investor Relations	21.40%	151,225	133,000
Communications	21.40%	61,262	71,000
Miscellaneous	21.40%	10,689	1,000
Travel	21.40%	291,452	283,000
Telephone	21.40%	39,668	38,000
Recoverable Amount		$ 8,771,431	$8,622,000

* *Actual Salary (EVP, Western Utility Operations) is included in Salaries (Excl EVPs, Western & Eastern Utility Ops).*

Please note that in 2018, FI corporate services costs have been allocated separately to FHI and FBC under the current allocation methodology. The proposed allocation methodology would be effective in the 2020 to 2024 MRP period.

142.2 For comparative purposes, please provide another version of Table D5-2 based on 2018 Actual FI corporate services costs eligible for allocation which uses the current methodology for allocating FI costs to FHI.

Response:

The requested version of Table D5-2 is provided below using the current methodology for allocating FI costs to FHI and FBC, respectively.

FI Recoverable Cost Categories	FHI portion of FI Costs 2018 ($) Actual	FBC portion of FI Costs 2018 ($) Actual
Salaries (Excl EVPs, Western & Eastern Utility Ops)	$3,541,000	$1,030,000
Salary (EVP, Western Utility Operations) *		
Directors' fees and costs	568,000	166,000
Trustees and DRIP administration	103,000	30,000
Consulting	391,000	114,000
Legal	339,000	99,000
Audit	284,000	83,000
Listing and filing	197,000	57,000
Annual meeting and report	177,000	52,000
Other fees	42,000	12,000
Insurance	174,000	51,000
Office related	454,000	132,000
Investor Relations	103,000	30,000
Communications	55,000	16,000
Miscellaneous	1,000	-
Travel	219,000	64,000
Telephone	30,000	8,000
Recoverable Amount	$6,678,000	$1,944,000

** Actual Salary (EVP, Western Utility Operations) is included in Salaries (Excl EVPs, Western & Eastern Utility Ops).*

Please note that the sum of 2018 actual FHI and FBC portions of FI corporate services costs above is $8.622 million, which agrees with the "FortisBC Subsidiaries Portion of FI Costs 2018 ($) Actual" column in the revised version of Table D5-2 provided in the response to BCUC IR 1.142.1.

142.3 Please identify the portion of the difference between the two versions of Table D5-2 provided above that is due to: (i) pooling FI corporate service costs previously charged directly to FBC with the FI corporate service costs charged to FHI; and (ii) updating the percentage allocation of FI corporate services to FHI from 41.94 percent to 21.4 percent.

Response:

As noted in the response to BCUC IR 1.142.2, there was $1.944 million of FBC costs previously charged directly to FBC that are proposed to be included in the pool of FHI costs to be allocated to FortisBC Subsidiaries. The Application only used 2018 forecast as a sample to prove the concept of the proposed allocation methodology. As of 2018, FI corporate costs were charged to FBC directly.

The 21.4 percent allocation of "FI corporate services to FHI" represents allocations used in 2018 of 16.5 percent to FHI and 4.9 percent to FBC respectively. The 41.94 percent of FI corporate services charged to FHI noted in the 2013 CS Study was only used in 2013. This ratio changes year to year based on FI's methodology of allocating costs and the number of subsidiaries owned; however, it is not necessarily reflective of a change in costs allocated. In other words, a different ratio could result in a similar cost being allocated.

143.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1-1, Appendix D5, p. 21

FHI Allocation Eligible Costs

Table 6.4 in Appendix D5 of the Application shows FHI's costs that are eligible for allocation based on 2018 FHI projected costs:

Table 6.4 – FHI 2018 Allocation Eligible Corporate Costs

FHI Corporate Services Cost Pools Eligible for Allocation	FHI Operating Costs	Specified Exclusions	Allocation Eligible Costs
Facilities & IT	$1,167,548	$(53,377)	$1,114,171
External Financial Reporting	797,018	(319,056)	477,962
Internal Audit	1,459,957	(70,000)	1,389,957
Treasury & Cash Management	1,066,259	(258,705)	807,554
Taxation	1,110,112	(204,149)	905,963
Legal	2,051,854	(240,000)	1,811,854
Insurance & Risk Management	273,341	(30,000)	243,341
Board Costs	1,236,410	-	1,236,410
Fortis Inc. Management Fee	8,771,431	(1,561,000)	7,210,431
Total	**$17,933,930**	**$(2,736,287)**	**$15,197,643**

143.1 Please provide a revised Table 6.4 (FHI costs eligible for allocation) based on 2018 Actual FHI costs.

Response:

Table 6.4 on page 21 of Appendix D5 has been revised and provided below to show the 2018 actual FHI operating costs, which consider certain 2018 actual FBC operating costs estimated as appropriately included in the pooling of FHI costs, and the 2018 actual FI Management Fee currently directly charged to FBC.

2018 Actual FHI Costs Example

FHI Corporate Services Cost Pools Eligible for Allocation	FHI Operating Costs	Specified Exclusions	Allocation Eligible Costs
Facilities & IT	1,197,148	(54,730)	1,142,418
External Financial Reporting	599,672	(140,056)	459,616
Internal Audit	1,333,476	(63,936)	1,269,540
Treasury & Cash Management	974,476	(176,436)	798,040
Taxation	779,563	(43,361)	736,202
Legal	1,983,163	(191,965)	1,791,198
Insurance & Risk Management	217,157	(23,834)	193,324
Board Costs	1,009,554	-	1,009,554
Fortis Inc. Management Fee	8,622,000	(1,437,000)	7,185,000
Total	**16,716,210**	**(2,131,318)**	**14,584,892**

While the requested table has been prepared for purposes of this IR, the final allocation of eligible costs do not necessarily represent the financial effects of implementing the proposed methodology during the MRP. As described in the responses to BCUC IRs 1.139.1.2 and 1.139.3.1, the FI and FHI fees were charged based on the current allocation methodology in 2018. Therefore, the allocation of eligible costs in the table above, which is prepared on the proposed methodology, is not representative of the actual corporate service costs included in FEI, ACGS, and FBC for 2018 using the current methodology.

144.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1-1, Appendix D5, p. 23

FHI Corporate Services Allocation Methodology

On page D-50 of the Application, FortisBC states that the allocation percentage of FHI corporate services to be applied to FEI, FBC and ACGS are 73 percent, 22 percent and 5 percent, respectively, based on the Massachusetts Formula. This is shown in Table 6.5 of Appendix D5 of the Application, as follows:

Table 6.5 – Financial Composite Formula Calculation as at December 31, 2017

	FEI	FBC	ACGS	FEI, FBC & ACGS Total
Gross Margin	$787,292,477	$217,649,059	$53,662,429	$1,058,603,964
	74.37%	20.56%	5.07%	100%
Payroll	$132,954,038	$46,290,792	$5,632,083	$184,876,913
	71.91%	25.04%	3.05%	100.0%
Average of NBV of PP&E + inventories	$4,361,337,041	$1,314,337,021	$444,647,627	$6,121,321,689
	71.26%	21.47%	7.27%	100%
Massachusetts Formula Allocation	**72.51%**	**22.36%**	**5.13%**	**100%**

144.1 Please provide the financial composite formula calculation (Table 6.4) as at December 31, 2018 and using 2018 Actuals.

Response:

Table 6.5 of Appendix D5 (not Table 6.4) outlining the financial composite formula calculation, using 2018 Actuals, has been provided below.

Financial Composite Formula as at December 31, 2018

	FEI	FBC	ACGS	FEI, FBC, & ACGS Total
Gross Revenue	865,107,975	255,759,907	62,010,693	1,182,878,575
	73.14%	21.62%	5.24%	100.00%
Payroll	146,697,789	47,382,224	4,109,233	198,189,246
	74.02%	23.91%	2.07%	100.00%
Average of NBV of PP&E + inventories	4,625,895,154	1,360,062,977	442,398,125	6,428,356,256
	71.96%	21.16%	6.88%	100.00%
Massachusetts Formula Allocation	**73.04%**	**22.23%**	**4.73%**	**100.00%**

145.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1-1, Appendix D5, p. 24; Exhibit B-1, Section D5.6, p. D-51

FEI and FBC Proportion of FHI Recoverable Costs

Table 6.6 in Appendix D5 of the Application shows the calculation of FEI and FBC's proportion of FHI recoverable costs using the allocation percentages for each entity indicated in Table 6.5:

Table 6.6 – 2018 FHI Operating Costs and FI Management Fee Allocation

	Allocation Eligible Costs	FEI (72.51%)	FBC (22.36%)	ACGS (5.13%)
Facilities & IT	$1,114,171	$807,944	$249,105	$57,122
External Financial Reporting	477,962	346,595	106,862	24,505
Internal Audit	1,389,957	1,007,930	310,765	71,262
Treasury and Financial Planning	807,554	585,600	180,552	41,402
Taxation	905,963	656,961	202,554	46,448
Legal	1,811,854	1,313,870	405,092	92,892
Insurance & Risk management	243,341	176,459	54,406	12,476
Board Costs	1,236,410	896,585	276,435	63,390
Fortis Inc. Management Fee	7,210,431	5,228,660	1,612,101	369,670
Total	**$15,197,643**	**$11,020,604**	**$3,397,872**	**$779,167**

145.1 Please provide a revised Table 6.6 based on 2018 Actual FHI costs eligible for allocation and the allocation percentages for each entity determined as at December 31, 2018.

Response:

Table 6.6 on page 24 of Appendix D5 has been revised using a Massachusetts Formula based on 2018 Actuals, as determined in BCUC IR 1.144.1, and provided below.

FI and FHI Corporate Services 2018 Allocation

	Allocation Eligible Costs	FEI (73%)	FBC (22%)	ACGS (5%)
Facilities & IT	1,142,418	834,422	253,959	54,036
External Financial Reporting	459,616	335,704	102,173	21,740
Internal Audit	1,269,540	927,272	282,219	60,049
Treasury & Cash Management	798,040	582,889	177,404	37,747
Taxation	736,202	537,722	163,658	34,822
Legal	1,791,198	1,308,291	398,183	84,724
Insurance & Risk Management	193,324	141,203	42,976	9,144
Board Costs	1,009,554	737,378	224,424	47,752
Fortis Inc. Management Fee	7,185,000	5,247,924	1,597,226	339,851
Total	**14,584,892**	**10,652,805**	**3,242,221**	**689,865**

As mentioned in the response to BCUC IR 1.143.1, using the actual operating costs for 2018 is misleading since the proposed methodology is based on budgeted figures, while actual costs in 2018 were charged based on the current allocation methodology. Therefore, the allocation of eligible costs in the table above is not representative of the actual fees included in FEI, ACGS, and FBC even before updating the Massachusetts Formula.

On page D-51 of the Application, FortisBC states that the below table calculates an FHI management fee of approximately $11.0 million and $3.4 million for FEI and FBC, respectively:

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**

145.2 Please explain the differences between the FEI and FBC portion of FHI recoverable costs as per Table 6.6 in Appendix D5 of the Application and Table D5-3 on page D-51 of the Application.

Response:

KPMG and FortisBC prepared the two tables on an independent basis; therefore, the difference between the FEI and FBC portion of recoverable costs between the two tables is due to rounding to different decimal points of the Massachusetts Formula. As shown in the table below, the variance is $155 due to this rounding.

	Table 6.6	Table D5-3	Variance
FEI Portion	11,020,604	11,018,669	1,935
FBC Portion	3,397,872	3,399,962	(2,090)
Total	**14,418,476**	**14,418,631**	**(155)**

The difference due to rounding does not change the request to apply the Massachusetts Formula to FHI Corporate Services during the term of the MRP. Rather, the forecasted quantitative effect on Base O&M due to applying this methodology has been quantified in the Revised Tables C2-1 and C2-14 in the responses to BCUC IR 1.24.1 and 1.34.1, respectively.

145.2.1 If it is not the name as the revised Table 6.6 provided in the IR above, please provide a revised Table D5-3 based on 2018 Actual FHI costs eligible for allocation.

Response:

As noted in the response to BCUC IR 1.145.2, there is no change to eligible costs for allocation. They are the same costs used in both Table 6.6 of Appendix D5 and Table D5-3 of the Application and the difference was solely due to rounding of the allocation formula.

146.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section C2.4.2, p. C-19

Corporate Services Study Impact on FEI 2019 Base O&M

FortisBC provides the following table on page C-19 of the Application:

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

[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).

146.1 Please confirm, or explain otherwise, that 2018 Actual FHI management fees (based on the current methodology of allocating common corporate service costs from FI and FHI to FEI) are included in the "2018 actual Base O&M" amount of $238.693 million in the table above.

Response:

Confirmed. The $238.693 million included in 2018 actual Base O&M includes the actual FI and FHI corporate services allocated to FEI during 2018.

146.1.1 If confirmed, please discuss whether FortisBC would consider the following alternative to Table C2-1 to be a reasonable approach to incorporating the allocation methodology for FI and FHI corporate services to FEI described in Section D5 and Appendix D5 of the Application. If not, please explain why not.

Alternative Table C2-1: FEI 2019 Base O&M ($ millions)

Line			
[1]	2018 actual Base O&M	$	238.693
[2]	Add temporary savings		1.677
[3]	Deduct 2018 actual FHI Management Fee		(x)
[4]	Adjusted 2018 Base O&M		Line [1]+[2]+[3]
[5]	2019 Inflator		1.02198
[6]	2019 Base O&M before adjustments		Line [4]*[5]
	Adjustments:		
	Exogenous Factors:		
[7]	2019 Z factor (EHT net of MSP)		0.972
	Deferrals:		
[8]	FAES overhead		0.786
[9]	BCUC levies		(2.778)
[10]	NGIF funding		(0.400)
	Flow Through treatment:		
[11]	Integrity Digs		(2.600)
[12]	LNG Plant O&M		5.101
[13]	2019 forecast FHI Management Fee[1]		x
[14]	Total adjustments		Line [7]+[8]+[9]+...[13]
[15]	New funding for MRP term	$	10.416
[16]	2019 Base O&M		Line [6]+[14]+[15]

[1] The 2019 forecast FHI Management fee estimated based on the allocation methodology described in Section D5

Response:

Based on the confirmation in the response to BCUC IR 1.146.1, the following alternative approach to Table C2-1 has been prepared:

Alternative Table C2-1: FEI 2019 Base O&M ($millions)

2018 actual Base O&M	$	238.693
Add temporary savings		1.677
Shared Services Studies Impact		(0.338)
Deduct 2018 actual FHI Management Fee		(12.383)
Adjusted 2018 Base O&M	$	227.649
2019 Inflator		1.02198
2019 Base O&M before adjustments	$	232.653
Adjustments:		
Exogenous Factors:		
2019 Z factor (EHT net of MSP)		0.972
Deferrals:		
FAES overhead		0.786
BCUC levies		(2.839)
NGIF funding		(0.409)
Flow Through treatment:		
Integrity Digs		(2.600)
LNG Plant O&M		5.101
2019 Forecast FHI Management Fee		11.563
2019 Reclass of FHI corporate services charged only to FEI		0.387
Total adjustments		12.961
New funding for MRP term	$	10.416
2019 Base O&M	$	256.030

While FEI agrees that, in principle, the above table provides a reasonable approach to incorporating the allocation methodology for FI and FHI corporate services to FEI, it does not consider that the forecast FI/FHI corporate services management fee to be allocated to FEI in 2020 is expected to be higher than the forecasted fee for 2019. Therefore, it is more appropriate to incorporate the 2020 forecasted FI/FHI corporate services allocation fee estimated to be charged to FEI and discounted back to 2019 for inflationary purposes in order to reflect the forecasted costs for 2020. The purpose of preparing Table C2-1 is to establish a forecast that will be utilized to set base O&M for 2020 and therefore, it should reflect the expected increase in 2020 FI/FHI corporate services.

In the response to BCUC IR 1.24.1, FortisBC provides a revised Table C2-1 with the expected financial effects of the FHI management fee included in 2019 Base O&M to be used for setting 2020 rates. FortisBC recommends the approach in the table in the response to BCUC IR 1.24.1 with the $256.150 million of 2019 Base O&M, rather than the approach in the above table in the response to this IR.

147.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-1, Section C2.5.2, p. C-44

Corporate Services Study Impact on FBC 2019 Base O&M

FortisBC provides the following table on page C-44 of the Application:

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

[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).

147.1 Please confirm, or explain otherwise, that 2018 Actual FHI corporate services and 2018 Actual FI corporate services directly charged to FBC are included in the "2018 actual Base O&M" amount of $53.839 million in the table above.

Response:

Confirmed. The $53.839 million included in the 2018 actual Base O&M includes the actual FI and FHI corporate services direct charged to FBC during 2018.

147.1.1 If confirmed, please discuss whether FortisBC would consider the following alternative to Table C2-14 to be a reasonable approach to

incorporating the allocation methodology for FI and FHI corporate services to FBC described in Section D5 and Appendix D5 of the Application. If not, please explain why not.

Alternative Table C2-14: FBC 2019 Base O&M ($ millions)

Line			
[1]	2018 actual Base O&M	$	53.839
[2]	Add temporary savings		0.500
[3]	Deduct 2018 actual FHI services direct charged to FBC		(x)
[4]	Deduct 2018 actual FI services direct charged to FBC		(x)
[5]	Adjusted 2018 Base O&M		Line [1]+[2]+[3]+[4]
[6]	2019 Inflator		1.02382
[7]	2019 Base O&M before adjustments		Line [5]*[6]
	Adjustments:		
	Exogenous Factors:		
[8]	2019 Z factor (EHT net of MSP)		0.240
[9]	2019 Z factor - MRS		1.540
	Deferrals:		
[10]	Manual meter read		0.180
	Flow Through treatment:		
[11]	AMI Project cost reductions		(1.161)
[12]	BCUC levies		(0.231)
[13]	2019 forecast FHI Management Fee[1]		x
[14]	Total adjustments		Line [8]+[9]+[10]+...[13]
[15]	New funding for MRP term	$	0.763
[16]	2019 Base O&M		Line [6]+[14]+[15]

[1] The 2019 forecast FHI Management fee estimated based on the allocation methodology described in Section D5

Response:

Based on the confirmation in the response to BCUC IR 1.147.1, an alternative approach to Table C2-14 has been prepared:

Proposed Alternative Table C2-14: FBC 2019 Base O&M ($millions)

2018 actual Base O&M	$	53.839
Add temporary savings		0.500
Shared Services Studies Impact		0.338
Deduct 2018 actual FHI services direct charged to FBC		(1.023)
Deduct 2018 actual FI services direct charged to FBC		(1.615)
Adjusted 2018 Base O&M	$	52.039
2019 Inflator		1.02382
2019 Base O&M before adjustments	$	53.279
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		(0.237)
2019 Forecast FHI Management Fee		3.339
FBC Costs included in FHI Corporate Services		(0.308)
Total adjustments		3.594
New funding for MRP term	$	0.763
2019 Base O&M	$	57.635

While FBC agrees that, in principle, that the above table provides a reasonable approach to incorporating the allocation methodology for FI and FHI corporate services to FBC, it does not consider that the forecasted FI/FHI corporate services management fee allocated to FBC in 2020 will differ from the forecasted fee for 2019. Therefore, it is more appropriate to incorporate the 2020 forecasted FI/FHI corporate services allocation fee estimated to be charged to FBC and discounted back to 2019 for inflationary purposes in order to reflect the forecasted costs for 2020. The purpose of preparing C2-14 is to establish a forecast that will be utilized to set base O&M for 2020 and therefore it should reflect the expected increase in 2020 FI/FHI corporate services.

In the response to BCUC IR 1.34.1, FortisBC provides a revised Table C2-14 with the expected financial effects of the FHI management fee included in 2019 Base O&M to be used for setting 2020 rates. FortisBC recommends the approach in the table in the response to BCUC IR 1.34.1 with the $57.670 million of 2019 Base O&M, rather than the approach in the above table in the response to this IR.

148.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1, Section D6.3, pp. D-54 – D-55; Exhibit B-1-1, Appendix D6-2, p. 3; Exhibit B-2, p. 6

Variances in Direct Charges to Capital and Other O&M Accounts

In the Workshop Material (Exhibit B-2), FortisBC provided the following numerical example to illustrate how variances in index-based O&M and Other Revenue affect achieved ROE and are shared through the ESM:

Line	Particulars	Forecast	Actual	Difference	Reference
1	Index-Based O&M	$255,000	$250,000	(5,000)	
2	Other Forecast O&M	$ 30,000	$ 30,000		variances to flow-through
3	Total Gross O&M	$285,000	$280,000		Line 1 + Line 2
4	Capitalized Overhead Percentage	16%			
5	Capitalized Overheads	(45,600)	(45,600)		-Line 3 x Line 4 (no variance)
6	Net O&M	$239,400	$234,400	**$ (5,000)**	
7					
8					
9	Other Revenue	(40,000)	(38,000)	**$ 2,000**	
10					
11	**Variance falls to earnings and increases achieved ROE (all else equal)**			**$ (3,000)**	Line 6 + Line 9

On page D-54 of the Application, FortisBC states "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."

For FBC, page 3 of Appendix D6-2 (2018 FBC Capitalized Overhead Study) states: "Both direct charges and direct overhead loading are removed from O&M costs which, when multiplied by the capitalization rate determined the Survey-based model, determine the amount of capitalized overhead."

148.1 Please amend the numerical example provided in the Workshop Material to include "direct charges to capital and other non-O&M accounts" and "direct overhead loading", and explain how variances in these items would impact annual ROE and the proposed 50/50 ESM, if at all.

Response:

To be clear, "direct charges to capital and other non-O&M accounts" and "direct overhead loading" are not classified as O&M costs to begin with. These two aforementioned cost categories are embedded as part of the capital forecasts of the Companies, and in the inflation-

indexed Growth capital mechanism for FEI. As such any variances in these cost categories would be dependent on which capital categories they were charged to, either directly or via loading. Assuming that the "direct charged to capital and other non-O&M accounts" and "direct overhead loading" are charged to regular capital, any variances between forecast and actual would follow the example provided in Exhibit B-2, Item 3, Regular Capital Variances (page 35 of FortisBC MRP Workshop Presentation), not the example cited in the preamble.

Finally, capitalized overheads 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. There are no variances in capitalized overheads because the Companies' actuals are booked to equal approved, therefore there is no impact to achieved ROE or the ESM from capitalized overheads.

149.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1, Sections D6.1, D6.3, pp. D-53, D-55; FEI PBR Application, Exhibit B-1, p. 288; FEI PBR Application proceeding, Exhibit B-1-1, p. 33, Appendix A; FBC PBR Application proceeding, Exhibit B-1, p. 252; FBC PBR Application, Exhibit B-1-1, p. 36, Appendix A

Methodology for FortisBC Capitalized Overhead Studies

On page D-55 of the Application, FortisBC states that 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.

On pages 288 and 252 of the FEI and FBC PBR Applications, respectively, FEI and FBC stated that it examined two methodologies to determine the capital overhead rate – a "survey-based model" and a "mathematical-based model." Based on the results of these two models, the Companies each put forward a proposed capitalized overhead rate for the BCUC's approval in the PBR Applications.

149.1 Please explain why FEI and FBC decided to use only a "survey-based approach" in the 2018 Capitalized Overhead Studies, as opposed to a "survey-based" and a "mathematical-based" approach as was provided in 2013.

Response:

FEI and FBC have historically used the survey-based approach in the last several capitalized overhead studies. The method was accepted by the BCUC and it is an appropriate approach for the capitalized overhead study, given it provides both qualitative and quantitative evidence to produce the studies.

The mathematical-based approach was introduced in the 2013 Capitalized Overhead Study only and was used to corroborate the proposed capitalized rate at that time. Upon review of the process and effectiveness of that study, FortisBC did not believe this would be an effective approach for the MRP and consequently modified its approach to this study. As discussed in more detail in the response to BCUC IR 1.149.1.1, the mathematical-based approach uses data collected from FortisBC departments, since it simply uses the budgeted O&M for each department as the base and allocates the costs over the selected drivers to determine the capital portion. Therefore, the individual activities and complexities for each of the different departments are not considered in the approach.

For example, the mathematical-based approach does not consider that different departments have varying levels of contributions to capital projects. Instead, the capital intensity factor is applied equally to each department whereas in reality, FBC and FEI execute capital projects using different resources both internally and externally.

FortisBC also notes that when an initial iteration of the mathematical-based approach was drafted earlier in the process of preparing the 2018 Capitalized Overhead Study, the resulting capitalized overhead rates were higher than using the survey based approach and what has been proposed in the MRP.

Given the combination of factors described above, FEI and FBC decided to apply a survey-based approach only for preparing the 2018 Capitalized Overhead Studies.

149.1.1 Please provide a detailed explanation of the pros and cons of a "survey-based approach" and the pros and cons of a "mathematical-based approach" to determine the capital overhead rate.

Response:

Survey-based approach - Pros and Cons

Pros:

- Consistent approach – using the same questions for all departments and having a consistent approach each time a study is performed allows for an efficient compilation and comparison of department results.
- Qualitative information received – departments were able to provide specific insight into various activities performed, whether the work was capital or O&M related, workforce management, etc.
- Broad representation – the survey questions were sent to all departments and data was gathered back from each of them. The volume and variety of data should theoretically provide a more accurate estimate of an average overhead rate.
- Easy to explore answers – after the initial survey responses were received, interviews were conducted with the respondents from the various departments, which helped provide additional insight into the data and ensure the data received was accurate.
- Consistency – FEI and FBC have utilized a survey-based approach as the foundation to establish capitalized overhead rates approved in previous rate filings.

Cons:

- Inflexible Design – the questions were determined ahead of time and could not be changed through the process of data gathering, otherwise the efficiencies created by standardizing the question would be lost. However, this did not preclude additional questions from being asked during the interview process.
- Potential for biased responses – Respondents may have biases to the survey questions.

Mathematical-based approach - Pros and Cons

Pros:

- Simplified – the approach only requires costs to be obtained and populated into a worksheet, which will provide a capital intensity factor to be applied to each department.
- Quick and easy – less time consuming since no interviews with individual departments would be required.

Cons:

- No feedback - does not include any communication with the individual departments and may not take into account newer activities required to support capital projects.
- Lack of details –there is no specific data collected from the departments other than the O&M for each department collected from Finance.
- Potential for biased mathematical data – biased data or factors may be applied.
- Not widely used within the industry – this approach was used once by FortisBC to corroborate the results from a survey-based approach, however our understanding is this type of approach isn't widely used.

149.1.2 Why was the "survey-based approach" selected as the methodology of choice over the "mathematical-based approach"? Please explain.

Response:

Please refer to the response to BCUC IR 1.149.1.

149.1.3 When considering the "pros" of the "mathematical-based approach" identified in the above IR, please explain whether the "survey-based approach" also addresses the advantages of the "mathematical-based approach". If not, please explain why FortisBC considers these advantages to be less significant.

Response:

The pros of the mathematical-based approach are its simplicity and that it is less time consuming, which are also its advantages over the survey-based approach. However, as discussed in the response to BCUC IR 1.149.1, the advantages of the mathematical-based approach do not overcome its disadvantages.

FortisBC notes that it has only prepared a study using the mathematical approach one time, in 2013. An excerpt from page 5 of KPMG's report from 2013 reviewing the study (for FEI) states:

> In order to provide an objective and reasonable basis of determining overhead capitalization, FEI undertook a capital cost allocation study. Two methodologies were used in the study – a Survey-based Model and a Mathematical Model. **Previously, the overhead capitalization rate for FEI was developed using the Survey-based Model approach.**
>
> These methodologies were evaluated based on a number of criteria to determine their appropriateness. **The examination of the two models provides a basis for the comparison between both approaches and allows a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards.**
>
> The Study utilized the BCUC approved 2013 FEI budget (the "2013 budget") figures pursuant to BCUC order G-44-12.
>
> **KPMG finds the FEI Survey-based capital cost allocation methodology, as detailed in Section 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead capitalization).** This methodology is consistent with internally generated evaluation criteria and practice established by the external guidance (referred to in this report), in

particular the requirements of U.S. GAAP under ASC 980 Regulated Operations. [emphasis added]

The reason why the mathematical approach was undertaken in 2013 was to provide a basis of comparison; it was not intended to be the basis for preparing the capitalized overhead estimate, and it was the survey-based approach that was approved at that time and in years prior.

FortisBC also understands that using a survey-based approach to determine capitalized overhead rates is more common for rate-regulated utilities as compared to the mathematical based approach which does not consider the qualitative aspects of indirect capital activities.

On page D-53 of the Application, FortisBC states that the proposed 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 charge to capital projects." [*Emphasis Added*]

149.2 Please explain how the design of the "survey based approach" takes into consideration costs related to capital activities that are directly charged to capital projects such that only the indirect overhead costs to capital projects are considered.

Response:

The survey based approach sought to gather two types of information from each department. The first was related to activities charged directly to capital by the department and the second explored how much of the department's O&M costs related to capital activities (indirect overhead costs). While the former provides support for the overall capital-related activities undertaken by each department and the Utilities as a whole, it is the latter that is used to determine the capitalized overhead rate as a percentage of O&M. For clarity, when FortisBC refers to its O&M in this study, it means the costs after direct charging to capital projects. Therefore, costs directly charged to capital have been excluded from the O&M studied.

In the 2013 FEI and FBC Capitalized Overhead Studies, KPMG stated on pages 33 and 36, respectively, that "An external survey was conducted by [FEI/FBC] management to determine the applied overhead capitalized rates across the United Stated and Canada."

The "External survey" results were included in Appendix A of both studies and the following main findings were noted:

- Among the utilities surveyed both in United States and Canada there is no single or common methodology for allocating indirect costs to capital.
- Utilities mostly use direct allocation, cost drivers and time (effort) studies for capitalization of indirect costs, which is a similar approach to the survey-based model.
- The capitalization rates range between 4% and 60% of O&M costs.
- A study of 18 Canadian and US utilities by Black and Veatch for Hydro One concluded that capitalization rates in Canada and the U.S. had an observed median of 19% and the range of overhead capitalization rates varied from 5% to greater than 50%.

149.3 Please provide an updated external analysis comparing the proposed capitalized overhead methodology and rate of FEI and FBC to other Canadian and US natural gas and electric utilities, respectively, reporting under US GAAP.

Response:

Since 2013, fewer utilities in Canada and the United States have publicly filed capitalized overhead studies. It is understood that there are more instances where utilities are internally updating capitalized overhead studies and implementing the results as part of their multi-year revenue requirements applications, rather than publicly filing studies and explicitly requesting approval for a rate. Not only does this make it difficult to acquire such information from other utilities, but it also indicates that there is no explicit, regulated standard to follow, resulting in diversity within the industry. As such, both KPMG and FortisBC had difficulty locating the requested information and an external survey of other utilities across the US and Canada was not included as part of the 2018 FEI and FBC Capitalized Overhead Studies (2018 Studies).

FortisBC is aware of the capitalized overhead rates applied in its own jurisdiction, which includes BC Hydro and PNG, which are approximately 10 percent and 6 percent respectively. However, these capitalized overhead rates and those of other utilities are not relevant comparatives as there are differences in how each utility operates and accounts for its capital activities. Therefore, FortisBC would not view these capitalized overhead rates as indicators for the appropriate rate to be implemented for FEI or FBC.

For example, BC Hydro is in the last two years of a ten-year plan to transition from capitalize overhead determined under Canadian GAAP, used prior to 2011, to capitalized overhead that is considered allowable under IFRS. This differs from FortisBC approach which is consistent with US GAAP, BC's Uniform System of Accounts (Gas & Electric) and US FERC reporting, and more closely resembles Canadian GAAP used prior to 2011. PNG is in a different stage of

capital investment compared to the FortisBC Utilities and therefore the level of capital activities within O&M is not expected to be comparable to FortisBC's circumstances.

On page 26 of the 2013 FEI and FBC Capitalized Overhead Studies, the capitalized overhead rates from KPMG's external survey "range[d] between 4 percent and 60 percent of O&M costs." The range of capitalized overhead rates shows that each utility's operating environment and practices are unique. An average or relevant rate cannot be extrapolated from the external survey since these rates are based upon the utility's unique characteristics such as size, location, volume of capital activities, business lines, etc. This again questions the relevance of including such information in the current capitalized overhead studies, as these cannot be compared directly to FortisBC.

Additionally, the external survey of other utilities conducted as part of the 2013 FEI and FBC Capitalized Overhead Studies (2013 Studies) does not provide sufficient relevance or context when compared to FortisBC's capitalized overhead rate.

149.3.1 If no external survey/analysis was conducted as part of the current capitalized overhead studies, please explain why not.

Response:

Please refer to the response in BCUC IR 1.149.3.

150.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1, Section D6.4, pp. D-55, D-58; Exhibit B-1-1, Appendix D6-1, p. 15, Appendix A; FEI PBR Application proceeding, Exhibit B-1-1, Appendix F3, p. 21; Exhibit B-3, Workshop Presentation, Slide 40

Results of Capitalized Overhead Study for FEI

On page D-55 of the Application, FortisBC states that it proposes a capitalized overhead rate of 16 percent of gross O&M for FEI. Table 1 in Appendix D6-1 (2018 FEI Capitalized Overhead Study) shows the build-up of the 16 percent rate for the FEI departments:

Table 1: Results of Survey Model (2018)

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	93,839	13,601	14%
Engineering	21,448	10,724	50%
Customer Service and Information Systems	63,244	6,321	10%
Market Developments and External Relations	25,141	5,692	23%
HR, Environment, Health & Safety, and Facilities	24,842	3,599	14%
Finance and Corporate	17,245	2,009	12%
Regulatory, Legal and Operation Supports	15,559	2,235	14%
Energy Supply and Resource Development	14,277	487	3%
Total	**275,595**	**44,668**	**16%**

The details of the survey questions used to interview the department heads and senior managers within the corporate functions and business units listed in Table 1 are provided in Appendix A to the 2018 FEI Capitalized Overhead Study.

150.1 Please explain how each of the responses from the nine survey questions provided in Appendix A of the 2018 FEI Capitalized Overhead Study are incorporated into the results shown in Table 1 of the study.

Response:

The nine survey questions were used to gather a broad range of information related to capital activities within the Utilities, including both qualitative and quantitative data. Explanations for how each of the individual questions were used in the Study are provided below, and FEI has re-inserted each of the questions for reference.

- Question 1 was used by both KPMG and FortisBC to understand the nature of the department activities and ensure all the activities were captured and assessed through the survey and interview process.

1. Please provide a brief overview of the activities for each of the O&M cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

- Questions 2 and 3 were used by KPMG to assess and quantify costs charged to capital projects directly (direct overhead). While this information was not used directly in the determination of the capitalized overhead rate in Table 1 of Appendix D6-1, which is based on indirect capital costs remaining in O&M only (indirect overhead), it did provide both KPMG and FortisBC some additional information on the total level of direct and indirect capital activities undertaken by each of the departments.

2. If your O&M cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross O&M cost centre budget before the direct charges to capital. E.g. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

3. What percentage of Labour do you forecast will be directly charged to capital for 2018, 2019 and 2020? If there is an expectation that the amount of direct charge will be changing over time, particularly during the term of the 2020-2024 Performance Based Regulation filing. Please provide a brief explanation for the change.

- Questions 4 through 8 were used by KPMG and FortisBC to assess and quantify the portion of indirect capital costs remaining in department O&M (indirect overhead).

4. Please describe the costs incurred by your department that are not directly charged to capital, but are still used to indirectly support the capital expenditure programs (i.e. remain within the O&M cost centre).

5. Would the O&M cost center operate with fewer staff and non-labour costs if the company hypothetically ceased to undertake all capital projects? If so – by how much would there be a reduction? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your O&M cost centre staffing be impacted?

6. How would the level of activities in your O&M cost center be impacted if the Company doubled its current level of capital expenditures? If so – by how much would there be an increase?

7. Of the 2018 amounts in each of your O&M cost centres that are not directly charged to capital projects please differentiate the activities (%)

split between the following categories: capital and operations and maintenance (O&M).

8. What percentage of your cost centre do you forecast will be spent to indirectly support capital activities (not directly charged to capital and remaining in your O&M cost centre) for 2018 (should be the same as the table in #7 above), 2019 and as part of the 2020-2024 Performance Based Regulation rate filing? If there is an expectation that these indirect activities will be changing over time, please provide a brief explanation for the change.

- Question 9 was used by KPMG to document the primary driver used for the estimate.

9. Please describe the primary driver that was used to estimate the percentage of O&M to indirectly support capital activities and not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc.). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

Since each department provides support for capital activities in different manners, the nine survey questions were used to assist KPMG and FortisBC management in arriving at the capitalized overhead rate for their departments.

The chart in Question 7 and the supplemental charts after the survey questions were used to document the quantitative measurements based on the estimates provided.

150.1.1 As part of the above response, please explain how the responses from the survey questions related to the costs charged directly to capital projects (e.g. survey question 2 and 3) are used (if at all) compared to the responses from the survey question related to the costs <u>not</u> charged directly to capital projects (e.g. survey question 4 and 7).

Response:

Please refer to the response in BCUC IR 1.150.1.

150.2 Please provide a breakdown of the capitalization rate for the departments into labour and non-labour cost components, and explain the results by department.

Response:

The breakdown of the capitalization rate into labour and non-labour cost components, based on results of the surveys, is provided below.

Department	Total O&M Costs ($000)	Total Capital Related ($000)	Capitalized Overhead Rate (%) - Labour	Capitalized Overhead Rate (%) - Non-Labour	Capitalized Overhead Rate (%) - Combined
Operations	93,839	13,601	9%	5%	14%
Engineering	21,448	10,724	33%	17%	50%
Customer Service and Information Systems	63,244	6,321	4%	6%	10%
Market Developments and External Relations	25,141	5,692	14%	8%	23%
HR, Environment, Health & Safety, and Facilities	24,842	3,599	10%	4%	14%
Finance and Corporate	17,245	2,009	3%	9%	12%
Regulatory, Legal and Operation Supports	15,559	2,235	7%	7%	14%
Energy Supply and Resource Development	14,277	487	3%	1%	3%
Total	**275,595**	**44,668**	**9%**	**7%**	**16%**

While the segregation of costs into labour and non-labour was requested from each department, it was primarily used to obtain an understanding of the nature of activities within each department, rather than to specifically drive the capitalized overhead rate.

The total labour and non-labour capital-related costs for each department were divided by the total O&M costs to calculate the labour and non-labour capitalization rates, respectively. The reason for providing separate results between labour and non-labour was to help provide some level of detail in analysis of the cost center instead of applying a more general response to the whole group. However, the differentiation between labour and non-labour doesn't impact how the capitalization rate is calculated or applied. To reconcile to the results of the overhead study, these labour and non-labour capitalization rates are added together to get a combined labour and non-labour capitalization rate, which is consistent with the combined capitalization rate, weighted by departmental capital-related costs, that arrives at the 16 percent FEI capitalized overhead rate.

Respondents were required to provide separate analysis for the labour and the non-labour components of their areas. Depending on each of the individual departments' level of involvement with capital activities, each department produced a different capitalization rate. One of the main drivers noted in the differences in non-labour capitalization rates between groups

was that some departments use more consultants, which if involved in performing capital-related work resulted in a higher non-labour capitalization rate. With respect to labour capitalization rates, departments involved with the planning, design and approval of capital work, such as Engineering, EH&S, and External Relations, had higher rates of capital-related activity and consequently a higher labour capitalization rate.

When KPMG and FortisBC reviewed the labour and non-labour costs in each department's O&M, the focus was on the nature of the labour and non-labour costs to determine if the costs were capital in nature. The split of costs between labour and non-labour itself is not a driver in determining the capitalized overhead rate.

The following requested explanation of results by department is based on the overall capitalized overhead rate, rather than segregating between labour versus non-labour as previously explained.

- Operations include customer service technicians, crew leaders, mechanics, equipment operators, pressure & measurement technicians, pipeline technicians and distribution service agents who charge directly to capital and O&M. Included in operations O&M are operations support representatives, dispatch coordinators and field operations assistants who support and enable the capital activities performed by the group of employees who charge directly to capital which amounted to 14 percent of Operations O&M.

- Engineering provides early stage planning prior to regulatory approval and construction of capital which are not charged to directly to specific capital projects. These capital activities amount to 50 percent of the Engineering O&M.

- Customer Service provide services for customer requests for new connection services and provide capital project information to customers. Information Systems provides services for IS technical support of employees who work on capital activities, as well as provide change management during implementation of new IT capital projects. These capital activities amount to 10 percent of the aggregated Customer Service and Information Systems O&M.

- Market Development and External relations provide support to file municipal applications for capital projects, including communication with neighborhood and indigenous communities effected by the projects, such as public hearings and complaint responses. These capital activities amount to 23 percent of the Market Development and External relations O&M.

- HR, Environment, Health & Safety, and Facilities provide support to capital projects for environmental assessments, ensuring safe work procedures are followed during capital projects and providing hiring and employee services for employees working on capital.

These capital activities amount to 14 percent of the aggregated HR, Environment, Health & Safety, and Facilities O&M.

- Finance and Corporate provide governance oversight of capital projects, financial accounting and reporting for capital projects, internal controls over financial reporting for project construction and debt issuances and equity injections to finance capital expenditures. These capital activities amount to 12 percent of the aggregated Finance and Corporate O&M.

- Regulatory, Legal and Operation Support provide back office support for capital projects, including the regulatory process to gain approval of capital expenditures, screening qualified contractors for capital projects, and evaluating construction contracts and related agreements. These capital activities amount to 14 percent of the aggregated Regulatory, Legal and Operation Support O&M.

- Energy Supply and Resource Development involves future energy resource planning, including LNG and RNG, which requires coordination with capital project planning. These capital activities amount to 3 percent of the aggregated Energy Supply and Resource Development O&M.

In the FEI PBR Application, Table 1 in Appendix F3 (2013 FEI Capitalized Overhead Study) shows the build-up of the (approximately) 12 percent rate for the FEI departments:

Table 1: Results of Survey Model (2013)

Department	Total Cost ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	63,189	11,008	17.4%
Customer Services	52,452	-	0.0%
Energy Solutions & External Relations	18,181	321	1.8%
Energy Supply & Resource Development	3,738	616	16.5%
Information Technology	25,379	7,131	28.1%
Engineering Services and PM	16,956	1,669	9.8%
Operations Support	12,990	2,953	22.7%
Facilities	9,259	121	1.3%
Environment, Health & Safety	2,999	750	25.0%
Finance & Regulatory Services	14,184	827	5.8%
Human Resources	8,511	1,414	16.6%
Governance	7,935	266	3.4%
Corporate	230	11	4.5%
Totals	**236,003**	**27,086**	**11.5%**

150.3 To the extent possible, please restate the information in Table 1 from the 2013 FEI Capitalized Overhead Study such that the FEI departments are organized in the same way as in Table 1 from the 2018 FEI Capitalized Overhead Study.

Response:

FEI has provided the requested re-stated table from the FEI 2013 Corporate Overhead Study below:

FEI 2013 Overhead Study Grouped to 2018 Departments

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	63,189	11,008	18%
Engineering	16,956	1,669	10%
Customer Service and Information Systems	77,831	7,131	9%
Market Developments and External Relations	18,181	321	2%
HR, Environment, Health & Safety, and Facilities	20,769	2,285	11%
Finance and Corporate	17,038	1,103	7%
Regulatory, Legal and Operation Supports	18,302	2,953	16%
Energy Supply and Resource Development	3,738	616	17%
Total	**236,003**	**27,086**	**12%**

It is important to acknowledge the 2013 amounts were pre-amalgamation of FEI with FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW). The 2013 Overhead rates also did not consider the higher level of regular capital activity experienced during the Current PBR Plan term at the time of the last study, nor do they consider the higher forecast regular capital expenditures expected to be incurred during the term of the MRP as described in Section C3.3 of the Application.

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 during the 2020-2024 MRP term, such as engineering, external relations, procurement, information systems, regulatory, legal, human resources and finance, to support the increased level of capital expenditures.

150.3.1 Please provide an explanation for significant increases/decreases in total O&M or capital-related costs by department.

Response:

As mentioned in the response to BCUC IR 1.150.3, the 2013 FEI O&M excluded O&M from FEVI and FEW. Therefore, the total O&M in Table 1 for 2013 and 2018 are not comparable.

However, to provide a sense of the more significant changes in capital related activity, based on dollar value, by department, the following explanations have been provided.

- Engineering – there are increases in capital related costs due to the upfront planning activities prior to construction of capital projects. For example, the labour and consultant

costs for the early stage planning of capital projects are not directly charged to specific capital projects.

- Market Development and External Relations – capital projects require working with indigenous communities. There are new compliance and communication requirements with municipalities and other levels of government. Where FortisBC's services are provided, high volumes of upfront communication and public hearings are required for construction projects. These requirements have increased over time and currently are requiring more effort than what was identified in the 2013 CS Study.

- HR, Environment, Health & Safety, and Facilities – there are increases in costs for employee services activities associated with a higher level of capital expenditures. For example, the HR, facilities and EH&S departments have all experienced an increase in effort and resources required to support capital related activities. FortisBC has also been increasing its focus on employee and customer health and safety by implementing the Target Zero program, with an increased focus on both capital and operating activities.

On page D-55 of the Application, FortisBC explains that the increase in the capitalization rate compared to the current 12 percent rate 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 is expected to continue over the Proposed MRP term."

On page D-58 of the Application, FortisBC states: "As shown in Table D6-1 above… The proportion of capitalized overhead to the annual capital expenditures is presented as the capitalization rate. A relatively consistent capitalization rate in 2020 as compare to the rate over the term of the Current PBR Plans is another indication that FEI's proposed capitalized overhead rate of 16 percent is within a reasonable range."

150.4 Please explain why an increase in capital activities increases the overhead capitalization rate (e.g. what are the underlying changes in FEI's business operations which are/have been needed to support increased capital spending and the associated cost since 2013).

Response:

An increase in capital activities results in a higher proportion of effort on capital activities when compared to O&M activities. While there is more direct charging to capital occurring, which is not part of the O&M studied, there is also a corresponding increase in support required from various business areas which may not normally charge directly to capital, such as finance,

human resources and legal. Additionally, there has been an increase in certain upfront capital activities provided by departments such as engineering and external relations, as described in the response to BCUC IR 1.150.3.1, which are not directly charging to capital, yet are required to execute capital expenditure plans. This increased support has resulted in not just an increase in gross O&M as shown in Table D6-1 in Section D6 of the Application, but also an increase in the level of support provided to capital-related activity within O&M. In the 2018 FEI Capitalized Overhead Study, KPMG and FortisBC identified these capital-related costs embedded in the O&M studied and included them in the determination of the capitalized overhead rate. As indicated in Figure 2 on page 16 of Appendix D6-1 in the Application, capital expenditures (excluding Capitalized Overhead) increased over 46 percent from $164 million in 2014 to $240 million in 2018.

The reasonableness of the proposed capitalized overhead rate was further assessed through the comparison of the proportion of capitalized overhead to annual capital expenditures, described as the capitalization rate in the response to BCUC IR 1.150.5 and shown in Table D6-1 on page D-57 of the Application. Since 2012, the proportion of capitalized overhead to annual capital expenditures (capitalization rate) ranges between 18 percent and 23 percent, with the 2020 projected capitalization rate approximating 21 percent. This comparison suggests that the proposed capitalized overhead rate of 16 percent beginning in 2020 results in a reasonable outcome when compared to prior years.

Similarly, Table D6-1 on page D-57 of the Application also shows that the net O&M, after allocating out the capitalized overhead to capital projects, remains relatively steady since 2012, with annual increases similar to inflation.

- the net O&M in 2012, after applying a capitalized overhead rate of 14 percent, is $226.255 million,
- the net O&M in 2014, after applying a capitalized overhead rate of 12 percent, is $232.368 million,
- the net O&M in 2016, after applying a capitalized overhead rate of 12 percent, is $239.026 million,
- the net O&M in 2018, after applying a capitalized overhead rate of 12 percent, is $242.555 million, and
- the net O&M in 2020, after applying the proposed capitalized overhead rate of 16 percent, is $243.509 million.

Comparing the trends of the proportion of capitalized overhead to annual capital expenditures, as well as reviewing the level of net O&M over multiple years, were ways in which FortisBC could assess the reasonableness of the 16 percent capitalized overhead rate that resulted from the survey-based approach.

150.5 Please explain why FortisBC considers its overall capitalization rate to be a factor in examining whether the proposed capitalization rate is within a reasonable range. As part of this response, please explain what FortisBC considers a "reasonable range".

Response:

To clarify, FortisBC used a capitalization rate (proportion of capitalized overhead to capex excluding capitalized overhead) as one measure to assess reasonability of the overhead rate, draw comparisons to prior periods and corroborate the results of the capitalized overhead study.

The overall capitalization rate is equal to:

Capitalized Overhead / Capex (excl. OH)

The statement around whether the capitalization rate is within a reasonable range is based on evaluating the results of the 2018 Capitalized Overhead study and whether it results in an overall capitalization rate that is relatively comparable to prior years. Table D6-1 on page D-57 in the Application shows a range of annual capitalization rates to approximate 20 percent (+/- 4%) since 2012. When applying the recommended 16 percent capitalized overhead rate from the 2018 study, it results in a 21 percent capitalization rate, which is in a reasonable range and comparable to the historical 20 percent capitalization rate since 2012.

If the results from the 2018 Capitalized Overhead Study were to result in a capitalization rate that approximated 30 percent, FEI would consider re-evaluating its proposed capitalized overhead as it would be outside a "reasonable range" compared to historical results.

As indicated in Table D6-1, the overall capitalization rates have dropped from 20 percent to 19 percent and 18 percent from 2017 through 2019, respectively. If FEI continued to use a capitalized overhead rate of 12 percent in 2020, the overall capitalization rate in 2020 would drop to 15 percent as calculated below:

	2020
Gross O&M	291,761
Cap OH Rate from 2014-2019 PBR	12%
Cap OH per PBR rate	35,011
Divide by Capex (excl. OH)	228,133
Overall Capitalization Rate	**15%**

The main driver of the decrease in the proportion of capitalized overhead to capex excluding capitalized overhead (capitalization rate) from 2017 to 2019 has been the increase in dollars spent on capital activities in proportion to dollars spent on O&M activities. FortisBC does not believe this should result in a decrease in the capitalization rate given the additional support required for capital activities within the gross O&M budget. As a result, in examining the capitalization rate for the MRP period, FortisBC considers the overall capitalization rate of 21 percent in Table D6-1 to be a more reasonable rate than the 15 percent as calculated above.

150.6 What parameters has FortisBC used to conclude that the capitalization rate in 2020 is "relatively consistent" to the rate over the term of the Current PBR Plans?

Response:

Please refer to the response in BCUC IR 1.150.5.

150.7 Please expand Table D6-1 to show FEI's projected capitalization rate for 2021 to 2024.

Response:

FEI is not able to provide the requested table as the O&M forecasts for 2021 through 2024 are not available. Assuming the mechanisms for determining formula O&M are approved as requested in the Application, those amounts will be determined annually using the formula index. As well, the flow-through items that are excluded from O&M indexing will be subject to approval by the BCUC through the Annual Review process each year.

Since O&M is the key factor used to derive the numerator for calculating the capitalization rate, as shown in BCUC IR 1.150.5, FortisBC is not able to expand Table D6-1 to show FEI's projected capitalization rate for 2021 to 2024.

Slide 40 of the Workshop Presentation shows the following revenue requirement impact of increasing the capitalized overhead rate by four percent for FEI:

Change in Rate	FEI	FBC
Capitalized Overhead Rate	+ 4% (16%)	+ 0% (15%)
Revenue Requirement Impact	**-$13.0 M**	**$0.0 M**

Table D2-2, page D-3 and Table D2-9, page D-23

It appears that the references to Table D2-2 and Table D2-9 in Slide 40, as provided in the above preamble, relate to the 2017 Depreciation Studies.

150.8 Please explain and provide the calculation for the -$13.0 million revenue requirement impact for FEI and provide corrected references, if appropriate, to the supporting tables in the Application. As part of the calculation, please show what the offsetting effects from increasing capital, and thereby rate base, are as separate line items.

Response:

The calculation requested has been included below. The increase in Capitalized Overhead rate reduces O&M, reduces Income Taxes and increases Earned Return. For purposes of the workshop materials $13.258 million was rounded to $13 million.

Line	Particulars	$000	Reference
1	Gross O&M	298,784	
2	Change in Cap OH rate	4%	Capitalized Overhead Study
3	Reduction in Net O&M	(11,951)	- Line 1 x Line 2
4			
5	Increase in Plant from Cap OH	11,951	- Line 3
6	Mid-year change in Rate Base	5,976	Line 5 / 2
7	Return on Rate Base	6.38%	
8	Earned Return	381	Line 6 x Line 7
9			
10	*Income Taxes*		
11	Equity Return	201	Line 6 x 38.5% x 8.75%
12	Change in Capitalized OH deduction for Income taxes	(3,984)	
13	CCA on Capitalzed OH	(780)	
14	Accounting Income After Tax	(4,562)	Line 11 + Line 12 + Line 13
15	Tax Rate	27%	
16	Accounting Income Before Tax	(6,250)	Line 14 / (1 - Line 15)
17	Income Tax	(1,687)	Line 15 x Line 16
18			
19	*Revenue Requirement*		
20	O&M	(11,951)	Line 3
21	Income Tax	(1,687)	Line 17
22	Earned return	381	Line 8
23	**Total**	**(13,258)**	Line 20 + Line 21 + Line 22

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151.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1, Sections C3.4.1, D6.4, D6.5, pp. C-61, C-81, D-55, D-58; Exhibit B-1-1, Appendix C4-1, p. 43; Exhibit B-1-2, p. C-64

Results of Capitalized Overhead Study

On page D-55 of the Application, FortisBC states that the proposed increase in the capitalized overhead rate for FEI 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."

On page D-58 of the Application, FortisBC states: "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."

Table C3-5 on page C-64 of the Evidentiary Update to the Application shows that FEI's forecast sustainment and other regular capital expenditures for 2020 through 2024 (average of the five years) are forecast to be approximately 7.1 percent higher than the average of the actual/projected capital expenditures for the years' 2017 through 2019.

The proposed increase to FEI's Base Growth Capital for the MRP term compared to Actual 2016 through 2018 growth capital, as shown in Table C3-3 on page C-61 of the Application, is approximately 15 percent.

Table C3-21 on page C-81 of the Application shows that FBC's forecast regular capital expenditures for 2020 through 2024 (average of the five years) are forecast to be 35 percent higher than the average of the actual/projected capital expenditures for the years' 2017 through 2019.

151.1 Please reconcile the higher forecast increases to FBC's regular capital during the proposed MRP term compared to the forecast increases to FEI' regular capital with FortisBC's proposals to increase FEI's capitalized overhead rate while maintaining FBC's current capitalized overhead rate.

Response:

For FEI, the proposed increase in the capitalized overhead rate aligns with both the actual increased capital spending seen during the Current PBR Plan period, and the increase in capital expenditures forecasted for the MRP period.

For FBC, the same increase in regular capital expenditures did not occur during the Current PBR Plan period, as shown in Table C3-20 on page C-81 of the Application. Further, the increase in capital expenditures forecast for the MRP period are primarily due to specific

projects related to system improvements and upgrades of aging generation assets. FBC will rely on external labour and consultants for these projects and the costs are expected to be directly charged to these projects. Therefore, the indirect capital-related costs included in O&M will not increase significantly despite the increase in capital spending, resulting in no proposed change to FBC's current capitalized overhead rate.

151.2 Please explain why, in consideration of the regular capital spending forecasts for FEI during the proposed MRP term, it would not be reasonable to maintain FEI's existing capitalized overhead rate.

Response:

In Sections D6.3 and D6.4 on pages D-54 to D-56 of the Application, FortisBC has provided various rationales as to why it is reasonable to update the capitalized overhead rate to 16 percent, rather than maintain at the existing rate, as follows:

- "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";

- "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";

- "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";

- "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)";

- "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";

- "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 preamble also appears to be comparing the regular capital spending forecasts for FEI and FBC during the proposed MRP term, where only FEI is requesting a change to its capitalized overhead rate. While both FEI and FBC are forecasting a higher level of capital expenditures during the MRP term, it is expected that FBC will direct charge a greater proportion of those activities as described in the response to BCUC IR 1.151.1.

In the article titled "The rise and decline of the X factor in performance-based electricity regulation" filed by FortisBC as Appendix C4-1 to the Application, it states the following on page 43: "Two types of incentive regulation are widely apparent for electricity distributors today: (1) capitalized expenses (or earning returns on expenses); and…"

151.3 Please discuss whether FortisBC's proposal to increase the capitalized overhead rate for FEI is connected to its focus on incentives as part of the proposed MRP. Please explain why or why not.

Response:

Capitalized overhead rates and incentives based on "capitalized expenses (or earning returns on expenses)" are not connected and represent two distinct concepts.

With respect to the determination of capitalized overhead rates, FortisBC, in consultation with KPMG, has performed an independent analysis of the capitalized overhead rates to ensure the rate is reflective of the indirect capital-related costs embedded in O&M. These studies are embedded as Appendices D6-1 and D6-2 in this Application.

With respect to incentives based on "capitalizing expenses (or earning returns on expenses)", this concept relates to situations where innovative O&M solutions are placed on a level playing field with capital solutions through the use of an incentive (such as the ability to capitalize expenses). FortisBC has provided an example of such an incentive in its response to BCUC IR 1.15.5. FortisBC has not proposed this type of incentive as part of its MRPs.

152.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1-1, Appendix D6-2, pp. 15–16; FBC PBR Application proceeding, Exhibit B-1-1, Appendix F3, p. 20

Results of Capitalized Overhead Study for FBC – Direct Overhead Loading

Table 1 on page 15 of the 2018 FBC Capitalized Overhead Study (Appendix D6-2) shows the build-up of the direct overhead load pool based on 2018 O&M costs is $5 million:

Table 1: Direct overhead loading results

Department	Function	2018 Direct Overhead Cost ($000s)
Operations – Okanagan	Management and Supervisory time	494
Operations - Kootenay	Management and Supervisory time	360
Project Management Office	Scheduling and administrative support	572
Engineering	Engineering and cost estimating	430
System Planning	T&D system planning & engineering	837
Environment, Health & Safety	Reporting, auditing project work	45
Line Construction	Management and Supervisory time	531
Finance	Accounts payable	87
Procurement & Materials Handling	Supply chain support	500
Distribution Engineering	Capital engineering, design and cost estimating	125
Engineering Standards	T&D Standards development & maintenance	170
System Control	System monitoring & communication	703
Station Capital	Supervisory & administrative support	158
Asset Management	Asset management planning & support	110
Distribution Projects	Local projects tying power from stations to customers	47
	Total	**5,168**

On page 16 of the 2018 FBC Capitalized Overhead Study, KPMG states the following:

> The methodology applied is consistent with the methodology of 2013, which resulted in actual direct overhead loadings of $4.7 million.
>
> In the absence of future significant regulatory, capital, accounting and organizational changes, the application of the direct overhead loading methodology is expected to continue to be appropriate in future periods.

The build-up of the $4.7 million direct overhead load pool based on the 2013 Budget was included in Appendix F3 (2013 FBC Capitalized Overhead Study) of the FBC PBR Application and is shown in the table below:

Table 1: Direct overhead loading results

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

152.1 Please explain the following increases/decreases in the direct overhead load pool from the 2013 FBC Capitalized Overhead Study to the 2018 Capitalized Overhead Study:

	Department	Function	2018 Direct Overhead Cost ($000s)	2013 Direct Overhead Cost ($000s)
(a)	Operations – Okanagan	Management and Supervisory Time	494	920
(b)	Engineering	Engineering and cost estimating	430	320
(c)	System Planning	T&D system planning & engineering	837	700
(d)	Line Construction	Management and Supervisory time	531	370
(e)	Procurement & Materials Handling	Supply chain support	500	150
(f)	System Control	System monitoring & communication	703	340
(g)	Asset Management	Asset management planning & support	110	360

Response:

Please refer to the table below which outlines the increases/decreases in the Direct Overhead load pool from 2013 to 2018:

1

	Department	2018 Direct Overhead Cost ($000s)	2013 Direct Overhead Cost ($000s)	Var	Description of Variance
(a)	Operations - Okanagan	494	920	(426)	Reduction in 2018 due to change in structure of personnel in the cost center. There were 15 people in Operations Okanagan in 2013 compared to 7 people in 2018 resulting in approximately half the cost
(b)	Engineering	430	320	110	2018 Direct Overhead costs are higher due to an additional FTE and a higher charge out to capital due to efforts required to support the overall T&D capital portfolio.
(c)	System Planning	837	700	137	System Planning and Asset Management staff are often interchangeable and work on various common capital initiatives. The spending is fairly consistent in 2013 & 2018 if two areas are consolidated. The remaining increase in 2018 is due to the implementation of the Asset Investment Planning Tool. This intitiative included the development of processes and methodologies to suport 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 Electric portfolio.
(d)	Line Construction	531	370	161	In 2013 the Line Construction budget is composed of the Kootenay Line Construction Group, in 2018 the Line Construction budget is composed of the North Okanagan and South Okanagan Line Construction Groups
(e)	Procurement & Materials Handling	500	150	350	2013 expenditures were significantly lower than average due to IBEW labour dispute disruption. Spending is generally levelized in the $500k range.
(f)	System Control	703	340	363	2018 Direct Overhead costs are higher due to an additional FTE and a higher charge out to capital due to efforts required to support the overall T&D capital portfolio.
(g)	Asset Management	110	360	(250)	See variance explanation under System Planning.

2

3

152.2 Please confirm, or explain otherwise, that the application of the direct overhead loading methodology results in a detailed analysis of the estimated capital-related cost for each of the departments who perform work for Transmission & Distribution (T&D) projects annually.

Response:

Confirmed.

152.2.1 If confirmed, please discuss how the direct overhead loading pool of $5 million based on the 2018 O&M costs is expected to change over the term of the proposed MRP term (e.g. increase, remain flat or decrease).

Response:

The direct overhead loading pool is expected to increase annually over the course of the proposed MRP term due to inflation.

153.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-1, Section D6.5, pp. D-58 – D-59; Section C3.4, p. C-18; Exhibit B-1-1, Appendix D6-2, pp. 15–16; FBC PBR Application proceeding , Exhibit B-1-1, Appendix F3, p. 20

Results of Capitalized Overhead Study for FBC – Overhead Capitalization

On page D-58 of the Application, FortisBC states that it proposes to maintain the capitalized overhead rate of 15 percent of gross O&M for FBC. Table 2 in Appendix D6-2 (2018 FBC Capitalized Overhead Study) shows the build-up of the 15 percent rate for the FBC departments:

Table 2: Results of Survey Model (2018)

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	23,424	3,888	17%
Engineering	5,379	538	10%
Customer Service and Information Systems	9,928	1,271	13%
Market Developments and External Relations	2,640	570	22%
HR, Environment, Health & Safety, and Facilities	5,971	747	13%
Finance and Corporate	6,545	1,144	17%
Regulatory, Legal and Operation Supports	3,461	305	9%
Energy Supply and Resource Development	1,245	124	10%
Total	**58,592**	**8,587**	**15%**

The details of the survey questions used to interview the department heads and senior managers within the corporate functions and business units listed in Table 1 are provided in Appendix A to the 2018 FBC Capitalized Overhead Study.

153.1 Please explain how each of the responses from the nine survey questions provided in Appendix A of the 2018 FBC Capitalized Overhead Study are incorporated into the results shown in Table 2 of the study.

Response:

Please refer to the response to BCUC IR 1.150.1

153.1.1 As part of the above response, please explain how the responses from the survey questions related to the costs charged directly to capital projects (e.g. survey question 2 and 3) are used (if at all) compared to the responses from the survey question related to the costs not charged directly to capital projects (e.g. survey question 4 and 7).

Response:

Please refer to the response to BCUC IR 1.150.1.

153.2 Please provide a breakdown of the capitalization rate for the departments into labour and non-labour cost components, and explain the results by department.

Response:

The breakdown of the capitalization rate into labour and non-labour cost components, based on results of the surveys, is provided below.

Department	Total O&M Costs ($000)	Total Capital Related ($000)	Capitalized Overhead Rate (%) - Labour	Capitalized Overhead Rate (%) - Non-Labour	Capitalized Overhead Rate (%) - Combined
Operations	23,424	3,888	9%	7%	17%
Engineering	5,379	538	8%	2%	10%
Customer Service and Information Systems	9,928	1,271	6%	7%	13%
Market Developments and External Relations	2,640	570	13%	9%	22%
HR, Environment, Health & Safety, and Facilities	5,971	747	6%	6%	13%
Finance and Corporate	6,545	1,144	8%	9%	17%
Regulatory, Legal and Operation Supports	3,461	305	3%	6%	9%
Energy Supply and Resource Development	1,245	124	7%	3%	10%
Total	**58,592**	**8,587**	**8%**	**7%**	**15%**

While the segregation of costs into labour and non-labour was requested from each department, it was primarily used to obtain an understanding of the nature of activities within each department, rather than to specifically drive the capitalized overhead rate.

The total labour and non-labour capital-related costs for each department were divided by the total O&M costs to calculate the labour and non-labour capitalization rates, respectively. The reason for providing separate results between labour and non-labour was to help provide some level of detail in analysis of the cost center instead of applying a more general response to the

whole group. However, the differentiation between labour and non-labour doesn't impact how the capitalization rate is calculated or applied.

To reconcile to the results of the overhead study, these labour and non-labour capitalization rates are added together to get a combined labour and non-labour capitalization rate, which is consistent with the combined capitalization rate weighted by departmental capital-related costs that arrives at the 15 percent FBC capitalized overhead rate.

Respondents were required to provide separate analysis for the labour and the non-labour components of their areas. Depending on each of the individual departments' level of involvement with capital activities, each department produced a different capitalization rate. One of the main drivers noted in the differences in non-labour capitalization rates between groups was that some departments use more consultants, which if involved in performing capital-related work resulted in a higher non-labour capitalization rate. With respect to labour capitalization rates, departments involved with the planning, design and approval of capital work, such as External Relations, had higher rates of capital-related activity and consequently a higher labour capitalization rate. Of note in the FBC results as compared to FEI, other departments engaged in planning, design and approval of capital work, such as Engineering and EH&S, direct charge their time which lowers the reported capitalization rate.

When KPMG and FortisBC reviewed the labour and non-labour costs in each department's O&M, the focus was on the nature of the labour and non-labour costs to determine if the costs were capital in nature. The split of costs between labour and non-labour itself is not a driver in determining the capitalized overhead rate.

The following requested explanation of results by department is based on the overall capitalized overhead rate, rather than segregating between labour versus non-labour as previously explained.

- Operations include customer service technicians, crew leaders, mechanics, equipment operators, power line technicians, electricians and distribution service agents who charge directly to capital and O&M. Included in operations O&M are operations support representatives, dispatch coordinators and field operations assistants who support and enable the capital activities performed by the group. The capital activities amount to 17 percent of Operations O&M.

- Engineering provides early stage planning prior to regulatory approval and construction of capital which are not charged to directly to specific capital projects. These capital activities amount to 10 percent of the Engineering O&M.

- Customer Service provide services for customer requests for new extensions and provide capital project information to customers. Information Systems provides services for IS technical support of employees who work on capital activities, as well as provide

change management during implementation of new IT capital projects. These capital activities amount to 13 percent of the aggregated Customer Service and Information Systems O&M.

- Market Development and External relations provide support to file municipal applications for capital projects, including communication with neighborhood and indigenous communities effected by the projects, such as public hearings and complaint responses. These capital activities amount to 22 percent of the Market Development and External relations O&M.

- HR, Environment, Health & Safety, and Facilities provide support to capital projects for environmental assessments, ensuring safe work procedures are followed during capital projects and providing hiring and employee services for employees working on capital. These capital activities amount to 13 percent of the aggregated HR, Environment, Health & Safety, and Facilities O&M.

- Finance and Corporate provide governance oversight of capital projects, financial accounting and reporting for capital projects, internal controls over financial reporting for project construction and debt issuances and equity injections to finance capital expenditures. These capital activities amount to 17 percent of the aggregated Finance and Corporate O&M.

- Regulatory, Legal and Operation Support provide back office support for capital projects, including the regulatory process to gain approval of capital expenditures, screening qualified contractors for capital projects, and evaluating construction contracts and related agreements. These capital activities amount to 9 percent of the aggregated Regulatory, Legal and Operation Support O&M.

- Energy Supply and Resource Development involves future energy resource planning, which requires coordination with capital project planning. These capital activities amount to 10 percent of the aggregated Energy Supply and Resource Development O&M.

In the FBC PBR Application, Table 2 in Appendix F3 (2013 FBC Capitalized Overhead Study) shows the build-up of the (approximately) 15 percent rate for the FBC departments:

Table 2: Results of Survey Model (2013)

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

153.3 To the extent possible, please restate the information in Table 2 from the 2013 FBC Capitalized Overhead Study such that the FBC departments are organized in the same way as in Table 2 from the 2018 FBC Capitalized Overhead Study.

Response:

FBC has provided the requested table below.

Table 1: Results of Survey Model (2013 Revision)

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	23,309	3,563	15%
Engineering	2,791	890	32%
Customer Service and Information Systems	10,515	954	9%
Market Developments and External Relations	1,469	114	8%
HR, Environment, Health & Safety, and Facilities	6,886	1,168	17%
Finance and Corporate	7,850	1,346	17%
Regulatory, Legal and Operation Supports	3,678	440	12%
Energy Supply and Resource Development	1,124	56	5%
Total	**57,621**	**8,531**	**15%**

153.3.1 Please provide an explanation for significant increases/decreases in total O&M or capital-related costs by department.

Response:

There were no significant increases or decreases in total O&M or capital-related O&M by department.

On page D-59 of the Application, FortisBC provides the following table:

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.

153.4 Please expand Table D6-2 to include the costs using FBC's projected capitalization rate for 2021 through 2024.

Response:

FBC is not able to provide the requested table given O&M forecasts for 2021 through 2024 are not available. Please also refer to the response to BCUC IR 1.150.7 which asks the same question for FEI.

Attachment 23.1

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
2013-2018 ACTUAL and 2019 Projected
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017	2018	2019 Projected
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Distribution Supervision	110-11	$ 11,898	$ 13,517	$ 13,764	$ 14,098	$ 15,020	$ 15,756	$ 14,789
2	Distribution Supervision Total	110-10	11,898	13,517	13,764	14,098	15,020	15,756	14,789
3									
4	Support - Distribution	110-21	10,145	11,030	11,343	9,654	8,295	9,048	9,400
5	Preventative Maintenance - Distribution	110-22	2,593	2,915	2,551	3,061	3,022	2,898	2,521
6	Operations - Distribution	110-23	7,613	7,318	6,801	7,411	7,559	8,424	7,949
7	Emergency Management - Distribution	110-24	6,595	6,490	6,111	5,902	6,028	6,344	6,614
8	Field Training - Distribution	110-25	3,546	3,427	2,705	3,600	2,967	3,411	2,732
9	Meter Exchange - Distribution	110-26	2,708	2,780	2,903	3,317	3,101	2,823	2,965
10	Distribution Operations Total	110-20	33,200	33,960	32,413	32,945	30,973	32,947	32,182
11									
12	Corrective - Distribution	110-31	6,842	5,536	5,663	5,401	5,977	7,182	7,055
13	Distribution Maintenance Total	110-30	6,842	5,536	5,663	5,401	5,977	7,182	7,055
14									
15	Account Services - Distribution	110-41	1,292	1,693	1,371	1,559	1,496	1,954	1,655
16	Bad Debt Management - Distribution	110-42	778	1,090	755	899	700	899	1,014
17	Distribution Meter to Cash	110-40	2,070	2,784	2,125	2,458	2,195	2,852	2,669
18									
19	**Distribution Total**	**110**	**54,010**	**55,797**	**53,964**	**54,903**	**54,166**	**58,738**	**56,694**
20									
21	Transmission Supervision	120-11	934	1,060	1,169	1,147	1,210	1,384	1,581
22	Transmission Supervision Total	120-10	934	1,060	1,169	1,147	1,210	1,384	1,581
23									
24	Pipeline / Right of Way Operations	120-21	10,486	11,865	12,403	13,890	13,820	14,001	16,360
25	Compression Operations	120-22	3,773	4,263	5,836	6,071	6,057	5,885	7,350
26	Measurement Control Operations	120-23	656	325	1,117	1,187	1,422	1,469	1,665
27	Transmission Operations Total	120-20	14,915	16,453	19,356	21,148	21,299	21,355	25,375
28									
29	Pipeline / Right of Way - Maintenance	120-31	837	460	1,275	230	315	537	-
30	Compression - Maintenance	120-32	563	717	1,360	1,043	698	1,025	-
31	Measurement Control Operations	120-33	280	356	148	192	182	121	-
32	Transmission Maintenance Total	120-30	1,681	1,533	2,783	1,465	1,195	1,683	-
33									
34	**Transmission Total**	**120**	**17,530**	**19,046**	**23,308**	**23,760**	**23,703**	**24,422**	**26,956** [1]
35									
36	LNG Plant Operations	130-11	4,331	4,698	4,967	6,110	7,716	11,011	12,614
37	LNG Plant Operations Total	130-10	4,331	4,698	4,967	6,110	7,716	11,011	12,614
38									
39	LNG Plant Maintenance	130-21	297	683	1,223	910	309	432	-
40	LNG Plant Maintenance Total	130-20	297	683	1,223	910	309	432	-
41									
42	**LNG Plant Total**	**130**	**4,629**	**5,380**	**6,190**	**7,019**	**8,025**	**11,443**	**12,614** [2]
43									
44	**Operations Total**	**100**	**76,169**	**80,224**	**83,463**	**85,682**	**85,894**	**94,603**	**96,264**
45									
46	Customer Service Supervision	200-11	491	814	287	291	298	(21)	-
47	Customer Assistance	200-12	12,089	12,302	10,493	10,159	10,181	9,906	11,131
48	Customer Billing	200-13	25,267	12,755	11,668	11,267	11,389	12,383	12,664
49	Meter Reading	200-14	12,453	11,383	11,274	11,631	11,709	11,791	12,544
50	Credit & Collections	200-15	3,004	4,997	2,452	1,815	2,467	1,517	2,005
51	Customer Operations	200-16	2,135	3,242	3,947	3,319	3,671	3,899	4,445
52	Customer Service Total	200-10	55,439	45,493	40,121	38,481	39,715	39,475	42,789
53									
54	**Customer Service Total**	**200**	**55,439**	**45,493**	**40,121**	**38,481**	**39,715**	**39,475**	**42,789**

[1] Transmission Operations and Maintenance costs are all reported in accounts 120-2x.

[2] LNG Operations and Maintenance costs are all reported in account 130-11.

The split between Operations and Maintenance activity for both Transmission and LNG is not available at the forecast level.

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
2013-2018 ACTUAL and 2019 Projected
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017	2018	2019 Projected
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Energy Solutions & External Relations Supervision	300-11	$ 1,014	$ 973	$ 971	$ 762	$ 923	$ 1,195	$ 1,433
2	Energy Solutions	300-12	6,443	6,480	7,695	8,204	8,179	9,217	8,695
3	Energy Efficiency	300-13	816	889	1,399	1,479	1,297	1,809	1,232
4	Corporate Communications & External Relations	300-14	7,146	7,411	8,852	8,155	9,218	8,271	7,861
5	Forecasting, Market & Business Development	300-15	5,957	6,181	6,056	6,589	6,463	7,512	8,598
6	Energy Solutions & External Relations Total	300-10	21,376	21,935	24,974	25,190	26,081	28,004	27,820
7									
8	**Energy Solutions & External Relations Total**	**300**	**21,376**	**21,935**	**24,974**	**25,190**	**26,081**	**28,004**	**27,820**
9									
10	Energy Supply & Resource Development	410-11	2,469	2,511	2,400	2,355	2,521	2,247	2,658
11	Gas Control	410-12	1,562	1,686	2,113	2,235	2,103	2,206	2,580
12	Energy Supply & Resource Development Total	410-10	4,031	4,196	4,513	4,590	4,624	4,453	5,238
13									
14	**Energy Supply & Resource Development Total**	**410**	**4,031**	**4,196**	**4,513**	**4,590**	**4,624**	**4,453**	**5,238**
15									
16	Information Systems Supervision	420-11	4,185	4,362	4,830	4,198	4,391	3,494	4,574
17	Application Management	420-12	13,728	13,850	14,594	15,590	12,717	14,134	13,278
18	Infrastructure Management	420-13	7,418	8,083	8,805	6,741	7,413	7,613	7,867
19	Information Systems Total	420-10	25,331	26,296	28,229	26,529	24,521	25,240	25,720
20									
21	**Information Systems Total**	**420**	**25,331**	**26,296**	**28,229**	**26,529**	**24,521**	**25,240**	**25,720**
22									
23	System Planning	430-11	7,607	6,837	7,086	7,035	7,039	6,995	7,206
24	Engineering	430-12	7,193	7,613	8,443	8,733	7,683	8,035	8,991
25	Project Management	430-13	1,014	933	850	614	774	1,526	2,534
26	Engineering Services & Project Management Total	430-10	15,814	15,383	16,379	16,382	15,496	16,556	18,731
27									
28	**Engineering Services & Project Management Total**	**430**	**15,814**	**15,383**	**16,379**	**16,382**	**15,496**	**16,556**	**18,731**
29									
30	Supply Chain	440-11	4,424	4,822	4,493	4,470	4,393	4,356	5,583
31	Measurement	440-12	6,129	7,012	7,589	7,028	6,534	7,057	6,253
32	Property Services	440-13	1,364	1,625	1,364	1,699	1,576	1,336	1,627
33	Operations Support Total	440-10	11,917	13,459	13,446	13,197	12,503	12,749	13,464
34									
35	**Operations Support Total**	**440**	**11,917**	**13,459**	**13,446**	**13,197**	**12,503**	**12,749**	**13,464**
36									
37	Facilities Management	450-11	9,739	9,719	9,537	9,836	10,383	10,028	10,400
38	Facilities Total	450-10	9,739	9,719	9,537	9,836	10,383	10,028	10,400
39									
40	**Facilities Total**	**450**	**9,739**	**9,719**	**9,537**	**9,836**	**10,383**	**10,028**	**10,400**
41									
42	Environment Health & Safety	460-11	2,680	2,910	3,159	3,669	4,217	4,527	5,232
43	Environment Health & Safety Total	460-10	2,680	2,910	3,159	3,669	4,217	4,527	5,232
44									
45	**Environment Health & Safety Total**	**460**	**2,680**	**2,910**	**3,159**	**3,669**	**4,217**	**4,527**	**5,232**
46									
47									
48	**Business Services Total**	**400**	**69,511**	**71,964**	**75,264**	**74,203**	**71,744**	**73,553**	**78,784**

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
2013-2018 ACTUAL and 2019 Projected
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017	2018	2019 Projected
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Financial & Regulatory Services	510-11	$ 13,363	$ 14,080	$ 13,599	$ 13,534	$ 13,391	$ 13,788	$ 14,471
2	Financial & Regulatory Services Total	510-10	13,363	14,080	13,599	13,534	13,391	13,788	14,471
3									
4	**Financial & Regulatory Services Total**	**510**	**13,363**	**14,080**	**13,599**	**13,534**	**13,391**	**13,788**	**14,471**
5									
6	Human Resources	520-11	8,305	9,285	9,109	9,015	9,049	9,483	10,202
7	Human Resources Total	520-10	8,305	9,285	9,109	9,015	9,049	9,483	10,202
8									
9	**Human Resources Total**	**520**	**8,305**	**9,285**	**9,109**	**9,015**	**9,049**	**9,483**	**10,202**
10									
11	Legal	530-11	2,299	2,174	1,814	2,056	1,809	1,768	1,842
12	Internal Audit	530-12	755	792	790	799	767	1,040	1,092
13	Risk Management/Insurance	530-13	5,990	6,491	6,599	5,888	5,603	5,520	5,802
14	Governance	530-10	9,044	9,457	9,204	8,743	8,179	8,328	8,737
15									
16	**Governance Total**	**530**	**9,044**	**9,457**	**9,204**	**8,743**	**8,179**	**8,328**	**8,737**
17									
18	Administration & General	540-11	481	187	(180)	(548)	483	(599)	(4,777)
19	Shared Services Agreement	540-12	4,525	5,164	4,481	5,159	5,096	4,914	4,859
20	Retiree Benefits	540-16	6,709	0	(0)	-	-	-	-
21	Corporate Total	540-10	11,715	5,351	4,301	4,611	5,579	4,316	82
22									
23	**Corporate Total**	**540**	**11,715**	**5,351**	**4,301**	**4,611**	**5,579**	**4,316**	**82**
24									
25	**Corporate Services Total**	**500**	**42,427**	**38,173**	**36,213**	**35,902**	**36,197**	**35,915**	**33,492**
26									
27	**Total Gross O&M Expenses**		**264,923**	**257,788**	**260,034**	**259,459**	**259,631**	**271,551**	**279,148**
28									
29	Less: Biomethane Transferred to BVA		-	(404)	(1,010)	(1,096)	(1,532)	(2,597)	(1,322)
30	Less: Capitalized Overhead		(38,233)	(32,605)	(32,457)	(32,594)	(32,313)	(33,076)	(33,738)
31									
32	**Total O&M Expenses**		**$ 226,690**	**$ 224,778**	**$ 226,568**	**$ 225,769**	**$ 225,786**	**$ 235,878**	**$ 244,088**

FORTISBC INC.

OPERATING AND MAINTENANCE EXPENSE
2013 - 2018 ACTUAL and 2019 PROJECTED
($000s)

Line No.	Account	Particulars	2013	2014	2015	2016	2017	2018	2019 Projected
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		GENERATION							
2	535R	Supervision & Administration	$ 815	$ 682	$ 778	$ 408	$ 446	$ 589	
3	536	Water Fees	9,397	9,600	9,714	10,182	10,316	10,264	
4	542	Structures	861	659	724	643	779	919	
5	543	Dams & Waterways	264	271	279	172	278	234	
6	544	Electric Plant	455	989	965	1,575	1,333	1,011	
7	545	Other Plant	159	358	373	307	223	335	
8			$ 11,951	$ 12,559	$ 12,832	$ 13,288	$ 13,374	$ 13,352	
9									
10		OTHER POWER SUPPLY							
11	555	Purchased Power	$ 83,052	$ 86,337	$ 110,707	$ 123,169	$ 133,214	$ 123,842	
12	556	System Control	2,076	2,207	2,140	2,298	2,211	2,263	
13			$ 85,128	$ 88,544	$ 112,847	$ 125,467	$ 135,425	$ 126,105	
14									
15		TRANSMISSION & DISTRIBUTION							
16	560R-1	Supervision & Administration	$ 1,704	$ 2,028	$ 2,257	$ 2,228	$ 2,039	$ 2,986	
17	560R-2	System Planning	2,277	2,764	2,862	3,074	3,256	3,914	
18	561	Load Dispatching	1,300	1,301	1,228	1,357	1,379	1,396	
19	562	Transmission Station Expense	1,016	922	921	847	870	723	
20	563R-1	Transmission Line Maintenance	632	468	625	539	586	622	
21	563R-2	Transmission Right of Way Maintenance	1,706	1,699	1,333	1,507	1,085	1,349	
22	565	Wheeling	5,225	5,132	4,800	4,815	5,124	5,523	
23	567	Rents	3,238	3,410	3,372	3,345	3,126	3,343	
24	583R-1	Distribution Line Maintenance	4,597	4,227	3,990	3,401	3,908	3,839	
25	583R-2	Distribution Right of Way Maintenance	3,785	4,121	4,124	3,817	4,374	4,109	
26	586	Meter Expenses	694	782	564	708	567	485	
27	592	Distribution Station Expense	1,607	1,682	1,197	1,790	1,700	1,625	
28	596	Street Lighting	48	90	66	68	51	72	
29	598	Other Plant	237	306	319	249	266	336	
30			$ 28,066	$ 28,932	$ 27,657	$ 27,745	$ 28,331	$ 30,322	
31		CUSTOMER SERVICE							
32	901	Supervision & Administration	$ 1,840	$ 1,680	$ 1,489	$ 1,722	$ 1,853	$ 2,064	
33	902	Meter Reading	1,763	2,228	1,683	231	212	250	
34	903	Customer Billing	720	628	572	594	569	615	
35	904	Credit & Collections	1,243	1,313	1,347	989	1,151	629	
36	910	Customer Assistance	2,616	3,031	2,473	2,688	2,716	2,850	
37			$ 8,183	$ 8,880	$ 7,565	$ 6,223	$ 6,501	$ 6,408	

FORTISBC INC.

OPERATING AND MAINTENANCE EXPENSE
2013 - 2018 ACTUAL and 2019 PROJECTED
($000s)

Line No.	Account	Particulars	2013	2014	2015	2016	2017	2018	2019 Projected
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		ADMINISTRATIVE AND GENERAL							
2	920	Salaries							
3	920.1	Executive and Senior Management	$ 848	$ 727	$ 885	$ 524	$ 551	$ 396	
4	920.2	Legal	740	803	544	692	474	639	
5	920.3	Human Resources	688	959	750	599	482	684	
6	920.4	Regulatory and Finance	917	1,429	1,254	1,223	941	627	
7	920.6	Information Services	832	1,486	1,591	1,216	1,377	1,373	
8	920.7	Materials Management	91	188	7	(10)	(95)	(80)	
9		Other	345	400	243	308	140	238	
10			$ 4,460	$ 5,992	$ 5,273	$ 4,551	$ 3,870	$ 3,878	
11									
12		ADMINISTRATIVE AND GENERAL cont'd							
13	921	Expenses							
14	921.1	Executive and Senior Management	$ 111	$ 28	$ 52	$ 45	$ 34	$ 27	
15	921.2	Legal	259	312	345	228	244	283	
16	921.3	Human Resources	137	109	163	98	83	46	
17	921.4	Regulatory and Finance	114	60	273	142	270	143	
18	921.6	Information Services	613	1,199	1,398	1,527	1,441	1,437	
19	921.7	Materials Management	61	256	293	343	370	426	
20		Other	267	242	353	181	296	294	
21			$ 1,562	$ 2,206	$ 2,877	$ 2,564	$ 2,740	$ 2,655	
22									
23	567	Special Services	$ 838	$ 1,914	$ 2,449	$ 2,887	$ 3,090	$ 2,951	
24	283R-1	Insurance	517	836	882	854	880	776	
25	283R-2	Maintenance to General Plant	1,450	1,294	1,253	1,392	1,388	1,478	
26	586	Transportation Equipment Expenses	689	528	508	258	243	270	
27			$ 3,494	$ 4,572	$ 5,092	$ 5,391	$ 5,601	$ 5,475	
28									
29		**TOTAL**	**142,845**	**151,686**	**174,142**	**185,229**	**195,843**	**188,195**	
30									
31	Less:	Water Fees	(5,225)	(5,132)	(4,800)	(10,182)	(10,316)	(10,264)	
32		Power Purchases	(83,052)	(86,337)	(110,707)	(123,169)	(133,214)	(123,842)	
33		Wheeling	(9,397)	(9,600)	(9,714)	(4,815)	(5,124)	(5,523)	
34		***Net O&M Expense***	***45,172***	***50,616***	***48,921***	***47,063***	***47,189***	***48,566***	***49,821***
35									
36	Add:	Capitalized Overhead	11,524	9,106	8,864	8,547	8,632	8,789	8,880
37									
38		***GROSS O&M Expense***	***56,696***	***59,723***	***57,785***	***55,609***	***55,821***	***57,355***	***58,701***

Attachment 23.11

8.0 Reference: The Target Zero Safety Program

In its response to COPE IR 7.1 in the FEI Annual Review of 2016 Rates (page 18 of Exhibit B-9), FEI outlined the following programs it intended to pursue as part of the Target Zero safety program.

- Annual employee safety perception survey that allows the company to better understand the current state of the safety culture and prioritize and implement initiatives that are relevant to employees.
- Targeted and relevant safety communications
    - Consistently branded safety communications and messaging throughout respective operating areas using different media formats including, stickers, banners, video, license plates and social media.
- Annual safety performance analysis developed for all business units
    - A safety analysis performed for each business unit that includes safety survey results, adherence to established internal programs, safety statistics, and review of the annual safety action plan, leadership engagement, employee involvement, regulatory compliance and hazard control.
- Safety action plans are created by each business unit on an annual basis that addresses findings from the annual safety performance analysis. This will become the blueprint for that business unit's safety improvement. This approach recognizes that all business units are not at the identical place in their safety evolution.
- Development and implementation of a new voluntary employee based safety program. A voluntary safety program developed and administered by the employees for the employees.

8.1 Please confirm that as of August 31, 2016 the Company has implemented each of these programs as part of its Target Zero safety program.

Response:

FEI has implemented the specified programs as stated in the response to COPE IR 7.1 in the FEI Annual Review for 2016 Rates.

- FEI's first annual employee safety perception survey was completed in October 2015 and is scheduled again in October 2016.

- Targeted and relevant safety communications have been delivered to all employees through monthly safety newsletters, videos, posters, safety meetings, safety related events and the FEI intranet.

- The inaugural safety performance analysis for each business unit was completed by the Occupational Health and Safety team and presented in December 2015. The 2016 safety performance analysis is scheduled to be completed and delivered in December 2016.

- All business units created their 2016 safety action plans which were presented to the Executive Leadership Team at the annual safety summit in January 2016. A status update was presented by all business units in May with another scheduled for October.

- An employee based safety program kicked off in January 2016 with employee representation from both office and field positions. The first program is targeting the elimination of "backing up" vehicle incidents and will be rolled out corporately beginning in September and continuing through the remainder of 2016.

8.2 If any these specified programs have not been implemented, please indicate whether FEI intends to implement them; if so, when FEI intends to implement them; and if not, why FEI has abandoned its intention to implement them.

Response:

Please refer to the response to MoveUP IR 1.8.1.

8.3 In its response to COPE IR 8.1 in the FEI Annual Review of 2016 Rates (page 21 of Exhibit B-9), FEI said, "FEI is planning to spend an incremental $750 thousand O&M in 2016 in support of the Target Zero program."

How much has FEI spent on the Target Zero program as of August 31, 2016?

Response:

FEI has spent incrementally approximately $570 thousand in O&M through August 31, 2016 on the Target Zero program.

The Company has implemented the Target Zero program and met all initial objectives. Costs incurred to date to support the program include: hiring additional safety professionals into the Occupational Health and Safety team; holding a safety summit for senior leadership; supporting employee based safety committee activities; developing a wider range of communication tools; and engaging third party consultants to assist in identifying further opportunities to support continuous improvement in safety.

Attachment 27.3

8.0 Reference: POTENTIAL FAILURE BY RUPTURE

Exhibit B-1, Section 3.3.2, p. 18

Evidence of External Corrosion on FEI's System

On page 18 of the Application, FEI states:

> FEI has experienced CP shielding on its pipeline system. Specifically, 72 of 90 integrity digs conducted on FEI's in-line inspected transmission pipelines in 2017 showed evidence of active corrosion on cathodically protected pipe. This means that the CP current designed to prevent corrosion is being prevented in these cases from reaching the steel surface of the pipeline.

8.1.2 For each integrity dig with identified corrosion, please provide costs to repair pipe, recondition or replace all or portions of the pipeline.

Response:

Please refer to the table below for recorded site-specific integrity dig costs for 2015, 2016, 2017 and 2018. FEI notes that its integrity dig costs are not collected in such a way to differentiate amongst excavation, inspection, repairs deemed to be an O&M expense, re-coating and site rehabilitation. In addition, prior to 2015, FEI only reported the total annual costs associated with integrity dig activity, as opposed to a specific cost for each dig site, so the information by site cannot be provided for those years.

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" PEN-VER - metal loss	2015	14,076
2015 Integrity Excavation	2015	41,912
2015 Integrity Excavation	2015	26,272
24" Nichol - Ferguson - Chainage 3593.6	2015	72,025
10" Grand Forks-Trail - Weld 32490	2015	1,143
10" Grand Forks-Trail - Weld 9340	2015	39,688
10" Grand Forks-Trail - Weld 16110	2015	23,918
10" Grand Forks-Trail - Weld 18200	2015	53,569
10" Grand Forks-Trail - Weld 19570	2015	40,788
10" Grand Forks-Trail - Weld 21710	2015	17,406
10" Grand Forks-Trail - Weld 22210	2015	26,622
10" Grand Forks-Trail - Weld 22400	2015	47,610
10" Grand Forks-Trail - Weld 22420	2015	21,720
10" Grand Forks-Trail - Weld 24320	2015	35,023
10" Grand Forks-Trail - Weld 27700	2015	69,190
10" Grand Forks-Trail - Weld 27980	2015	4,822
10" Grand Forks-Trail - Weld 32480	2015	281,164
10" Grand Forks-Trail - Weld 37360	2015	14,645
10" Grand Forks-Trail - Weld 38590	2015	22,891
10" Grand Forks-Trail - Weld 39580	2015	35,692
10" Grand Forks-Trail - Weld 42480	2015	9,791
10" Grand Forks-Trail - Weld 43520	2015	12,017
10" Grand Forks-Trail - Weld 43740	2015	5,282
10" Grand Forks-Trail - Weld 43800	2015	15,704
10" Grand Forks-Trail - Weld 44070	2015	37,367

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 46320	2015	23,873
10" Grand Forks-Trail - Weld 46360	2015	27,898
10" Grand Forks-Trail - Weld 46440	2015	13,231
10" Oliver Y - Grand Forks - Weld 2010	2015	18,184
10" Oliver Y - Grand Forks - Weld 17950	2015	25,392
10" Oliver Y - Grand Forks - Weld 28320	2015	21,848
10" Oliver Y - Grand Forks - Weld 28790	2015	19,672
10" Oliver Y - Grand Forks - Weld 28930	2015	13,647
10" Oliver Y - Grand Forks - Weld 38030	2015	24,864
10" Oliver Y - Grand Forks - Weld 46180	2015	17,207
10" Oliver Y - Grand Forks - Weld 46900	2015	7,197
10" Oliver Y - Grand Forks - Weld 47000	2015	11,096
10" Oliver Y - Grand Forks - Weld 55600	2015	24,389
10" Oliver Y - Grand Forks - Weld 57560	2015	18,200
10" Oliver Y - Grand Forks - Weld 59800	2015	7,681
10" Oliver Y - Grand Forks - Weld 60500	2015	8,858
10" Oliver Y - Grand Forks - Weld 62430	2015	8,124
10" Oliver Y - Grand Forks - Weld 65140	2015	13,254
10" Penticton - Oliver Y - Weld 7530	2015	19,418
10" Penticton - Oliver Y - Weld 17710	2015	74,587
10" Penticton - Oliver Y - Weld 5500	2015	19,384
10" Penticton - Oliver Y - Weld 11830	2015	11,204
10" Penticton - Oliver Y - Weld 22680	2015	23,763
12" Penticton-Vernon - Weld 5840	2015	18,734
12" Penticton-Vernon - Weld 6740	2015	175
12" Penticton-Vernon - Weld 60030	2015	16,701
12" Savona - Vernon - Weld 3280	2015	542
12" Savona - Vernon - Weld 16960	2015	7,927
12" Savona - Vernon - Weld 18070	2015	9,989
12" Vernon-Penticton - Weld 4440	2015	966
12" Yahk - Trail (EKL) - Weld 41470	2015	14,513
12" Yahk - Trail (EKL) - Weld 51360	2015	64,315
12" Yahk - Trail (EKL) - Weld 55780	2015	8,855
12" Yahk - Trail (EKL) - Weld 83640	2015	20,728
8" Trail-Castlegar - Weld 16090	2015	52,722
8" Trail-Castlegar - Weld 3090	2015	23,793

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 43550	2015	31,509
12" Savona - Vernon - Weld 43850	2015	18,218
2015 Integrity Excavation	2015	42,084
12" Livingston - Coquitlam - Weld 18120	2015	1,534
24" Nichol - Ferguson - Weld 1450	2015	31,841
24" Nichol - Ferguson - Chainage 3549.9	2015	92,996
168 mm PG#1 Lateral - Chainage 92.6	2015	12,667
168 mm PG#1 Lateral - Chainage 3822.7	2015	26,399
168 mm PG#1 Lateral - Chainage 4397.3	2015	2,565
2015 Integrity Excavation	2016	80,415
12" Livingston - Coquitlam - Weld 6830	2016	22,088
12" Livingston - Coquitlam - Weld 10030	2016	17,139
12" Livingston - Coquitlam - Weld 12530	2016	35,168
12" Livingston - Coquitlam - Weld 24190	2016	36,793
18" Livingston - Pattullo - Weld 10120	2016	73,365
18" Livingston - Pattullo - Weld 12040	2016	36,436
18" Livingston - Pattullo - Weld 12660	2016	28,025
20" Cape Horn - Burrard - Weld 10550	2016	46,085
10" Watershed - Secret Cove Weld 15260	2016	14,475
10" Watershed - Secret Cove Weld 19370	2016	11,612
8" Campbell River Lateral Weld 1160	2016	8,616
8" Campbell River Lateral Weld 26140	2016	13,810
10" Grand Forks-Trail - Weld 39040	2016	22,408
10" Grand Forks-Trail - Weld 39370	2016	17,582
10" Grand Forks-Trail - Weld 43860	2016	15,977
10" Grand Forks-Trail - Weld 46300	2016	17,124
10" Grand Forks-Trail - Weld 44150	2016	7,786
10" Grand Forks-Trail - Weld 44920	2016	10,920
8" Trail-Castlegar - Weld 370	2016	28,493
8" Trail-Castlegar - Weld 5360	2016	43,594
10" Grand Forks-Trail - Weld 14730	2016	24,307
10" Grand Forks-Trail - Weld 16920	2016	23,693
10" Grand Forks-Trail - Weld 17330	2016	19,491
10" Grand Forks-Trail - Weld 20830	2016	28,176
10" Grand Forks-Trail - Weld 21120	2016	25,755
10" Grand Forks-Trail - Weld 25620	2016	25,883

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 27980	2016	266,052
10" Grand Forks-Trail - Weld 31310	2016	15,018
10" Grand Forks-Trail - Weld 32830	2016	23,975
10" Grand Forks-Trail - Weld 37890	2016	51,388
10" Grand Forks-Trail - Weld 37910	2016	8,853
10" Grand Forks-Trail - Weld 43740	2016	80,286
10" Oliver Y - Grand Forks - Weld 13490	2016	25,485
10" Oliver Y - Grand Forks - Weld 24200	2016	19,651
10" Oliver Y - Grand Forks - Weld 25520	2016	20,514
10" Oliver Y - Grand Forks - Weld 26410	2016	13,761
10" Oliver Y - Grand Forks - Weld 28110	2016	16,874
10" Oliver Y - Grand Forks - Weld 28240	2016	22,601
10" Oliver Y - Grand Forks - Weld 28600	2016	21,547
10" Oliver Y - Grand Forks - Weld 31350	2016	11,724
10" Oliver Y - Grand Forks - Weld 20200	2016	28,741
10" Oliver Y - Grand Forks - Weld 32620	2016	22,165
10" Oliver Y - Grand Forks - Weld 36130	2016	24,759
10" Oliver Y - Grand Forks - Weld 31460	2016	19,474
10" Oliver Y - Grand Forks - Weld 42300	2016	16,876
10" Oliver Y - Grand Forks - Weld 43390	2016	27,657
10" Oliver Y - Grand Forks - Weld 56680	2016	30,231
10" Oliver Y - Grand Forks - Weld 56790	2016	15,523
10" Oliver Y - Grand Forks - Weld 38030	2016	11,980
10" Oliver Y - Grand Forks - Weld 61580	2016	17,015
10" Penticton - Oliver Y - Weld 12290	2016	14,404
10" Penticton - Oliver Y - Weld 15870	2016	19,223
12" Penticton-Vernon - Weld 2670	2016	29,869
12" Penticton-Vernon - Weld 4440	2016	11,032
12" Penticton-Vernon - Weld 5180	2016	21,752
12" Penticton-Vernon - Weld 6740	2016	35,900
12" Penticton-Vernon - Weld 15880	2016	22,972
12" Penticton-Vernon - Weld 16600	2016	20,661
12" Penticton-Vernon - Weld 27010	2016	27,264
12" Penticton-Vernon - Weld 27120	2016	20,041
12" Penticton-Vernon - Weld 34870	2016	91,463
12" Penticton-Vernon - Weld 53010	2016	29,211

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Penticton-Vernon - Weld 58440	2016	26,216
12" Princeton-Oliver - Weld 29460	2016	47,072
12" Savona - Vernon - Weld 3280	2016	31,297
12" Savona - Vernon - Weld 16279	2016	64,242
12" Savona - Vernon - Weld 24190	2016	17,698
12" Savona - Vernon - Weld 39340	2016	37,403
12" Savona - Vernon - Weld 45450	2016	24,040
12" Savona - Vernon - Weld 84810	2016	23,599
16" SONG - Weld 17460	2016	32,615
8" Trail-Castlegar - Weld 3090	2016	222,018
8" Trail-Castlegar - Weld 8610	2016	16,611
12" Kingsvale - Oliver - Weld 30580	2016	24,783
12" Yahk - Trail (EKL) - Weld 51170	2016	18,489
12" Yahk - Trail (EKL) - Weld 55780	2016	33,703
8" Trail-Castlegar - Weld 4920	2016	20,407
ILI Integrity Excavation -Trail/Cast 219	2016	38,731
12" Yahk - Trail (EKL) - Weld 99380	2016	44,503
12" Yahk - Trail (EKL) - Weld 96930	2017	42,523
24" Nichol - Port Mann, Weld #1990	2017	73,027
24" Nichol - Port Mann, Weld #3850	2017	46,078
24" Nichol - Port Mann, Weld #4060	2017	66,338
24" Nichol - Port Mann, Weld #4210	2017	37,079
20" Tilbury - Fraser, Weld #4940	2017	36,299
20" Tilbury - Fraser, Weld #5680	2017	44,568
24" Nichol - Fraser, Weld #6710	2017	38,665
12" Livingston - Coquitlam, Weld #16340	2017	58,390
2015 Integrity Excavation	2017	67,779
2015 Integrity Excavation	2017	64,414
2015 Integrity Excavation	2017	19,614
2015 Integrity Excavation	2017	587
2015 Integrity Excavation	2017	43,737
2015 Integrity Excavation	2017	2,251
2015 Integrity Excavation	2017	61,469
ILI Inspection Digs VI10 2017	2017	30,114
10" Oliver Y - Grand Forks - Weld 12900	2017	52,522
10" Oliver Y - Grand Forks - Weld 20780	2017	27,939

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Oliver Y - Grand Forks - Weld 22650	2017	63,684
10" Oliver Y - Grand Forks - Weld 23030	2017	17,495
10" Oliver Y - Grand Forks - Weld 23630	2017	18,515
10" Oliver Y - Grand Forks - Weld 28380	2017	20,523
10" Oliver Y - Grand Forks - Weld 28800	2017	16,451
10" Oliver Y - Grand Forks - Weld 28810	2017	26,501
10" Oliver Y - Grand Forks - Weld 32920	2017	54,086
10" Oliver Y - Grand Forks - Weld 36160	2017	18,849
12" Savona - Vernon - Weld 4520	2017	31,932
12" Savona - Vernon - Weld 9710	2017	31,998
12" Savona - Vernon - Weld 10960	2017	9,042
12" Savona - Vernon - Weld 24680	2017	14,007
12" Penticton-Vernon - Weld 5590	2017	21,829
12" Penticton-Vernon - Weld 7250	2017	107,408
12" Penticton-Vernon - Weld 2200	2017	52,428
12" Savona - Vernon - Weld 32880	2017	34,655
12" Savona - Vernon - Weld 42580	2017	26,997
12" Savona - Vernon - Weld 60260	2017	30,962
12" Savona - Vernon - Weld 93650	2017	18,770
PG Pulp Lateral 168 - Int Dig	2017	7,378
PG Pulp Lateral 168 - Int Dig	2017	7,470
PG Pulp Lateral 168 - Int Dig	2017	10,263
PG Pulp Lateral 168 - Int Dig	2017	5,721
PG Pulp Lateral 168 - Int Dig	2017	8,784
PG Pulp Lateral 168 - Int Dig	2017	37,925
PG Pulp Lateral 168 - Int Dig	2017	14,329
PG #1 Lateral 168 - Int Dig	2017	39,690
PG #1 Lateral 168 - Int Dig	2017	30,327
PG #1 Lateral 168 - Int Dig	2017	27,112
PG #1 Lateral 168 - Int Dig	2017	65,056
10" Grand Forks-Trail - Weld 7840	2017	34,506
10" Grand Forks-Trail - Weld 9240	2017	31,637
10" Grand Forks-Trail - Weld 16090	2017	17,863
10" Grand Forks-Trail - Weld 18400	2017	15,220
10" Grand Forks-Trail - Weld 21190	2017	43,048
10" Grand Forks-Trail - Weld 22390	2017	38,165

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 24730	2017	14,048
10" Grand Forks-Trail - Weld 24760	2017	25,253
10" Grand Forks-Trail - Weld 25700	2017	9,737
10" Grand Forks-Trail - Weld 26990	2017	83,839
10" Grand Forks-Trail - Weld 27820	2017	192,094
10" Grand Forks-Trail - Weld 31160	2017	16,245
10" Grand Forks-Trail - Weld 33390	2017	35,567
10" Grand Forks-Trail - Weld 33450	2017	13,932
10" Grand Forks-Trail - Weld 33890	2017	18,060
10" Grand Forks-Trail - Weld 37370	2017	32,839
10" Grand Forks-Trail - Weld 39780	2017	13,231
10" Grand Forks-Trail - Weld 39790	2017	39,184
10" Grand Forks-Trail - Weld 43070	2017	22,062
10" Grand Forks-Trail - Weld 43590	2017	46,979
10" Grand Forks-Trail - Weld 44380	2017	9,908
10" Grand Forks-Trail - Weld 44390	2017	18,412
10" Grand Forks-Trail - Weld 44400	2017	23,490
10" Grand Forks-Trail - Weld 44430	2017	13,244
10" Grand Forks-Trail - Weld 44470	2017	13,492
10" Grand Forks-Trail - Weld 44860	2017	31,955
10" Grand Forks-Trail - Weld 45140	2017	29,943
10" Grand Forks-Trail - Weld 45270	2017	38,078
10" Grand Forks-Trail - Weld 45400	2017	33,767
10" Grand Forks-Trail - Weld 45410	2017	25,642
10" Grand Forks-Trail - Weld 45950	2017	22,107
10" Oliver Y - Grand Forks - Weld 23060	2017	10,374
10" Oliver Y - Grand Forks - Weld 36190	2017	14,783
10" Oliver Y - Grand Forks - Weld 38220	2017	24,012
10" Oliver Y - Grand Forks - Weld 38290	2017	4,523
10" Oliver Y - Grand Forks - Weld 39760	2017	14,463
10" Oliver Y - Grand Forks - Weld 44120	2017	33,450
10" Oliver Y - Grand Forks - Weld 48830	2017	46,539
10" Oliver Y - Grand Forks - Weld 55560	2017	9,575
10" Oliver Y - Grand Forks - Weld 56540	2017	15,185
10" Oliver Y - Grand Forks - Weld 64520	2017	14,495
12" Savona - Vernon - Weld 59600	2017	156,972

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 74300	2017	55,304
12" Savona - Vernon - Weld 78840	2017	12,136
12" Savona - Vernon - Weld 88870	2017	22,236
12" Savona - Vernon - Weld 92210	2017	57,043
12" Savona - Vernon - Weld 101010	2017	50,950
10" Penticton - Oliver Y - Weld 17730	2017	53,268
12" Yahk - Trail (EKL) - Weld 53100	2017	27,575
Trail to Castlegar Intg Dig Weld1240	2017	23,510
Integrity Dig Weld 1770 TRA-CAS-8"	2017	11,099
Integrity Dig Weld 6980 TRA-CAS-8"	2017	33,677
Integrity Dig Weld 14290 TRA-CAS-8"	2017	19,604
Integrity dig LIV-COQ weld 1520	2018	18,777
Integrity dig LIV-COQ weld 11840	2018	74,785
Integrity dig TIL-BEN weld 3260	2018	156,765
Integrity dig LIV-PAT weld 12520	2018	54,007
Integrity dig LIV-PAT weld 14370	2018	32,692
integrity dig LIV-PAT weld 16350	2018	31,439
Integrity dig LIV-PAT weld 21690	2018	47,531
integrity dig CAP-BUR weld 8020	2018	55,676
integrity dig CPH-BUR weld 13450	2018	34,876
integrity dig CPH-BUR weld15620	2018	39,610
integrity dig NIC-PTM weld 4520	2018	41,747
integrity dig NIC-FRA weld 9660	2018	3,193
Integrity dig LIV-COQ weld 2590	2018	3,425
12" Savona - Vernon - Weld 19040	2018	11,150
12" Savona - Vernon - Weld 35600	2018	8,003
VI10 2018 ILI Digs	2018	12,665
10" Penticton - Oliver Y - Weld 3360	2018	23,386
10" Penticton - Oliver Y - Weld 7840	2018	67,613
10" Oliver Y - Grand Forks - Weld 65690	2018	5,019
12" Vernon-Penticton - Weld 37190	2018	14,104
12" Savona - Vernon - Weld 5900	2018	34,899
12" Savona - Vernon - Weld 5920	2018	30,532
12" Savona - Vernon - Weld 8020	2018	8,571
12" Savona - Vernon - Weld 9500	2018	12,967
12" Savona - Vernon - Weld 9540	2018	7,974

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 9760	2018	8,810
12" Savona - Vernon - Weld 16500	2018	10,147
12" Savona - Vernon - Weld 22410	2018	22,124
12" Savona - Vernon - Weld 24680	2018	4,072
12" Savona - Vernon - Weld 33820	2018	50,031
12" Savona - Vernon - Weld 35790	2018	9,622
12" Savona - Vernon - Weld 35850	2018	8,103
12" Savona - Vernon - Weld 37120	2018	17,699
12" Savona - Vernon - Weld 40120	2018	11,779
12" Savona - Vernon - Weld 43640	2018	15,315
12" Savona - Vernon - Weld 64840	2018	7,948
12" Savona - Vernon - Weld 92120	2018	20,819
12" Savona - Vernon - Weld 92230	2018	7,728
10" Oliver Y - Grand Forks - Weld 23500	2018	12,508
10" Oliver Y - Grand Forks - Weld 28250	2018	22,471
10" Oliver Y - Grand Forks - Weld 46070	2018	16,097
10" Oliver Y - Grand Forks - Weld 47000	2018	9,493
10" Oliver Y - Grand Forks - Weld 47570	2018	40,929
10" Oliver Y - Grand Forks - Weld 53100	2018	15,281
10" Oliver Y - Grand Forks - Weld 56930	2018	16,258
10" Oliver Y - Grand Forks - Weld 59770	2018	19,394
10" Grand Forks-Trail - Weld 21260	2018	37,266
10" Grand Forks-Trail - Weld 31140	2018	26,523
10" Grand Forks-Trail - Weld 44220	2018	26,608
10" Grand Forks-Trail - Weld 44230	2018	18,144
10" Grand Forks-Trail - Weld 44550	2018	26,663
10" Grand Forks-Trail - Weld 44880	2018	40,873
10" Grand Forks-Trail - Weld 46380	2018	14,641
8" Trail - Castlegar - Weld 1510	2018	28,720
12" Yahk - Trail (EKL) - Weld 40200	2018	43,765
12" Yahk - Trail (EKL) - Weld 87800	2018	25,576
12" Kingsvale - Princeton - Weld 14330	2018	44,324
12" Kingsvale - Princeton - Weld 36510	2018	22,324
12" Kingsvale - Princeton - Weld 37250	2018	25,135
12" Princeton - Oliver - Weld 34380	2018	29,468
12" Princeton - Oliver - Weld 39150	2018	18,859

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Princeton - Oliver - Weld 43500	2018	22,277
8" Trail - Castlegar - Weld 3330	2018	36,317
8" Trail - Castlegar - Weld 5300	2018	17,201
8" Trail - Castlegar - Weld 5800	2018	112,200
8" Trail - Castlegar - Weld 5920	2018	20,979
8" Trail - Castlegar - Weld 6200	2018	22,535
8" Trail - Castlegar - Weld 6210	2018	19,720
8" Trail - Castlegar - Weld 7150	2018	19,912
8" Trail - Castlegar - Weld 8160	2018	21,081
8" Trail - Castlegar - Weld 8860	2018	12,814
8" Trail - Castlegar - Weld 9060	2018	30,930
8" Trail - Castlegar - Weld 13220	2018	20,875
8" Trail - Castlegar - Weld 13270	2018	21,398
8" Trail - Castlegar - Weld 15480	2018	19,376
8" Trail - Castlegar - Weld 16100	2018	134,011
12" Savona - Vernon - Weld 42070	2018	39,750
12" Savona - Vernon - Weld 42090	2018	120,101
12" Savona - Vernon - Weld 42150	2018	12,612
12" Savona - Vernon - Weld 110800	2018	13,727
12" Savona - Vernon - Weld 111150	2018	39,952
12" Savona - Vernon - Weld 111170	2018	11,389

Attachment 28.8

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7701
fortisbc.com

November 30, 2017

Submitted via e-mail to: integrityengineering@bcogc.ca

Frank Austin, BA Sc., MBA., P.Eng.
Vice President, Engineering
Energy Infrastructure and Integrity
BC Oil and Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: FortisBC Energy Inc. (FEI) submission of IMP-Facilities (IMP-F) Self-Assessment

Dear Frank,

In response to Industry Bulletin 2017-11 issued June 28, 2017, entitled "New Requirements for Integrity Management Programs for Facilities", please find attached FEI's evaluation of IMP-F requirements, using the self-assessment questionnaire provided on the BC Oil & Gas Commission's (BC OGC) website, for the following facilities:

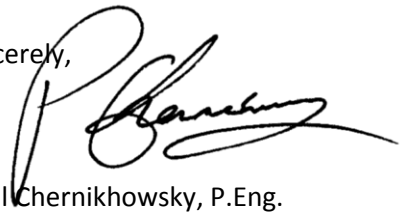
1. Compressor stations
2. LNG production plants

FEI recognizes that permit holders are required by the BC OGC to develop, implement, and maintain an IMP-F to assess and manage risks over the entire life cycle of the facility, to reduce incidents and to ensure safe, environmentally responsible and reliable operation of the asset. FEI also notes that IMPs are mandated in the Pipeline Regulation and Liquefied Natural Gas (LNG) Facility Regulation, as applicable to its operation.

As suggested by the phrase "New Requirements" in the title of the bulletin, FEI agrees that there is significant content and guidance contained within the Compliance Assurance Protocol and self-assessment questionnaire that does not exist within the applicable Regulations or associated Canadian Standards Association standards. As required by the BC OGC, FEI has completed its self-assessment to these newly published protocols.

FEI would also like to clarify that the self-assessment questionnaire requires permit holders to select between compliant or non-compliant. FEI considers that its historical performance demonstrates that it is a safe and prudent operator. In many cases, FEI has considered that its practices are compliant and meet the intent of regulations and standards and "partially compliant" to the new protocol requirements. Therefore, FEI submits that a self-evaluation of "non-compliant" should not be interpreted as FEI not having sufficient controls in place for the assessment and management of risks over the life cycle of its facilities, or that it is not adequately ensuring the safe, environmentally responsible and reliable operation of its assets.

Sincerely,



Paul Chernikhowsky, P.Eng.
Director, Engineering Services
FortisBC Energy Inc.

attachments:

IMP-F questionnaire: FEI Compression assets (PDF and Word versions)
IMP-F questionnaire: FEI LNG assets (PDF and Word versions)

cc: Michael Leclair, Director, Generation and Compression
Darren Julyan, Director, Gas Plant Operations & PMO

Self-assessment of IMP-F for FortisBC LNG assets

Summary of corrective actions

Please note that several deficiencies have related corrective actions; and have been grouped into common corrective actions per the summary below.

Self-assessment #	Corrective action	Timeframe for corrective actions	Related self-assessment #	Related corrective action
A1.1	1. A documented IMPF for LNG assets (excluding the risk assessment and management related elements that are covered by the corrective action for item B1.1) will be developed. 2. A documented IMPF for LNG assets (including the risk assessment and management related elements that are covered by the corrective action for item B1.1) will be developed.	1. June 30, 2020 2. June 30, 2021	A3.3	The task to develop a documented Integrity Compliance Directory will be included in the scope for the CA for item A1.1.
			D1.1	Descriptions for roles involving the IMPF for LNG assets will be included in the scope for the CA for item A1.1.
			D1.2	The communication of the descriptions for roles involving the IMPF for LNG assets will be included in the scope for the CA for item A1.1.
			F1.7	The task to update the Gas System Assets Records Table and setup as a company standard will be included in the scope for the CA for item A1.1.
			G1.1	The task to develop a process for MOC organizational and procedural changes will be included in the scope for the CA for item A1.1.
			N1.1	Audit requirements for the LNG asset IMPF will be included in the scope for the CA for item A1.1.
B1.1	A documented risk assessment and management process will be developed.	December 31, 2020	B1.2	The definitions for ALARP will be included in the scope for the CA for item B1.1.
			B2.3	The task to identify material information that is required to effectively implement its integrity management program for all LNG plants; and to develop strategies for the absence of that material information will be included in the scope for the CA for item B1.1.
			B6.1	A process for prioritization of facilities, equipment and piping based on risk assessment process will be included in the scope for the CA for item B1.1.
			H1.5	Developing content for operational controls will be included in the scope for the CA for item B1.1.
			I1.1	A risk assessment process for developing IMM programs will be included in the scope for the CA for item B1.1.
			I1.2	The key elements of the various IMM activities will be included in the scope for the CA for item B1.1.
			I1.5	A process to ensure that the results of its IMM activities are integrated with data for its risk assessment and performance measures will be included in the scope for the CA for item B1.1.
E1.1	The competency management program for LNG Operators will be reviewed, updated and documented.	December 31, 2020	E1.2	A process for maintaining training schedules and frequencies for identified critical tasks will be included in the scope for the CA for item E1.1.
			E1.3	A process for verifying employee and contractor's training and competency will be included in the scope for the CA for item E1.1.
			H1.5	Developing content for operational controls will be included in the scope for the CA for item E1.1.
H1.1	A process will be developed for the maintenance of Plant Operations manuals and job procedures.	December 31, 2020	H1.2	Same as H1.1.
			H1.3	Same as H1.1.

IMPF Self-assessment Reporting Document

Permit Holder Name	FortisBC Energy Inc. (FEI)
Permit Holder Address	16705 Fraser Highway, Surrey, BC
Self-Assessment Filing Date	November 30, 2017
Contact Person	Paul Chernikhowsky
Contact Person Title	Director, Engineering Services
Email	paul.chernikhowsky@fortisbc.com

Instructions:

Please complete all sections. Responses to questions must be selected from the drop down menu provided (Yes, No, N/A, etc.) and concise comments should be included to provide further description to demonstrate compliance. All relevant documents and references must be listed with version or revision numbers. Identified deficiencies must be thoroughly explained and must also include a specific time-frame for all specified corrective actions.

No.	Questions	Permit Holder Response	Comments	Documents and References	Deficiencies	Timeframe for corrective actions
A	**LEADERSHIP COMMITMENT**					
A1	**Scope**					
			FEI is a natural gas utility that serves approximately one million customers in BC. It has approximately 3000 kms of pipelines and associated facilities that are regulated by the BC OGC.	All FEI documents pertaining to the Integrity Management Policy and the various Integrity Management Program (IMP) activity standards exist in electronic format. These documents are accessible to all FEI employees via FEI's IT network; however, the ability to make changes is restricted to the document owners. Hard copies of the referenced documents will be provided upon request.		
A1.1	Has the permit holder documented, established and maintained an IMPF for all of the facilities under the jurisdiction of the Commission?	No	The "no" is because LNG assets are currently within the scope for CRL 1056 (Integrity Management Program) and elements of an IMPF are in place for LNG, full documentation for an IMPF for these assets does not currently exist. An IMPF specifically for LNG assets is under development. CRL 1021 (Policy: Integrity Management) includes scope for LNG assets. The leadership commitment, policy and objectives are common for all FEI gas system assets	• Integrity Management Policy (CRL 1021) • Integrity Management Program (CRL 1056)	**DEFICIENCY:** Full documentation for an IMPF for LNG assets does not exist **CORRECTIVE ACTION:** 1. A documented IMPF for LNG assets (excluding the risk assessment and management related elements that are covered by the corrective action for item B1.1) will be developed. 2. A documented IMPF for LNG assets (including the risk assessment and management related elements that are covered by the corrective action for item B1.1) will be developed. Note: Included in the scope of this CA will be deficiencies identified in other items of this self-assessment.	1. June 30, 2020 2. June 30, 2021
A1.2	How does the leadership ensure the effectiveness of the IMPF through a positive safety culture?					
	The company's leadership has established a program for "target zero" that includes the active engagement of employees in achieving this goal. (see Connector page) FEI has a Safety & Environmental Policy (CRL 1032) that includes the safety of our employees, contractors and the public, as well as the environment. The corporate scorecard has a specific metric for the safety of employees; which is posted monthly (most recent posting attached). Benchmarking with other utility companies are used in establishing performance targets. Such performance metrics are used as a factor in management and exempt employee's incentive plan. The company has established joint health and safety committees that meet monthly to discuss safety issues and concerns.					

A1.3	Has the permit holder clearly identified the facilities/equipment, and the processes managed under the IMPF?	Yes	FEI's Integrity Management Policy (CRL 1021) specifically includes LNG assets in its scope.	• Integrity Management Policy (Appendix B)		
A1.4	Using the table below, outline the facilities covered by the IMPF.					

Type of Facilities	Number of Facilities	Comments	Documents and References	Deficiencies	Timeframe for Corrective Actions
Facilities downstream of Gas Plant	n/a				
Surface Upstream Facilities	n/a				
Gas processing plants	n/a				
LNG facilities	3	LNG facilities included in this self-assessment include: ~ Tilbury Island (1970) ~ Tilbury 1A (in progress) ~ Mt Hayes (2011)	Refer to system map.		
Other, please specify	n/a				

A1.5	Are facilities that are covered by other programs and documentation within the scope of the IMPF properly referenced?	n/a				
A1.6	Does the permit holder have a third party operating any of its facilities in BC?	No				
A1.7	If yes, describe how many facilities are operated by third parties.					
	n/a					
A1.8	Describe the contractual agreement(s) between the parties, especially the IMPF requirements, and how the permit holder ensures that third parties are fulfilling contractual agreement requirements with respect to facility integrity.					
	n/a					
A2	**Policy and Commitment**					
A2.1	Has the permit holder's senior leadership articulated policy and leadership commitment to its IMPF?	Yes	The Safety & Environment Policy (CRL 1032) was approved by Michael Mulcahy (President and CEO) on January 28, 2015 The Integrity Management Policy (CRL 1021) was revised and approved by Doyle Sam (Executive VP, Operations and Engineering) on April 18, 2017. The performance of the IMP is reviewed at a frequency specified by senior leadership (minimum semi-annually) by the use of dashboards and review meetings.	• Safety & Environment Policy (CRL 1032) • Integrity Management Policy (CRL 1021) • IMP Management Review Report		
A2.2	Has senior leadership signed and communicated policy and commitment within the organization to ensure safety and integrity?	Yes	The Safety & Environment Policy (CRL 1032) and the Integrity Management Policy (CRL 1021) are available to all employees on the company's intranet site (Connector). A story titled "The Power of Proactive Pipelining" was posted on Connector on Sept 25, 2017.	• Safety & Environment Policy (CRL 1032) • Integrity Management Policy (CRL 1021) • Connector article: "The Power of Proactive Pipelining" was posted on Sept 25, 2017.		
A2.3	Explain how senior leadership is committed to the IMPF, overall goals and objectives, providing resources, fostering risk management processes, and implementing and continually improving the integrity management program.					
	The performance of the IMP is reviewed at a frequency specified by senior leadership (minimum semi-annually) by the use of dashboards and review meetings. The review meetings include discussion on levels of unsatisfactory performance and alternatives for achieving the desired performance level, which include the provision of resources, improvement of processes and the use of new or better technology.					
A3	**Planning**					
A3.1	Has the permit holder's management ensured that processes and procedures are defined to support the execution of all key components of the IMPF?	Yes	These are defined in Integrity Management Program (CRL 1056).	• Integrity Management Program (CRL 1056)		

A3.2	Does the permit holder have documented methods for collection, integration and analysis of information related to the processes and mechanisms appropriate to the type of facility and operation covered by the IMPF?	Yes	Goals, objectives and KPIs are monitored per IMP Management Review for effectiveness. When these are unsatisfactory, reviews for improvements are conducted and implemented.			
A3.3	Does the permit holder have a process to address regulatory and legal requirements, and ensure that facilities are designed, constructed, operated, and abandoned in accordance with the relevant applicable BC regulations and standards?	No	The regulatory and legal requirements are not currently documented. An Integrity Compliance Directory is currently under development (CA 1956) and planned for approval in 2018 Q2.		**DEFICIENCY:** The regulatory and legal requirements are not currently documented. **Note:** The task to develop a documented Integrity Compliance Directory will be included in the scope for the CA for item A1.1.	
A3.4	Has the permit holder ensured that plans, processes and procedures are integrated to ensure that data and results are shared (internally and externally), across relevant elements, processes, and teams as required?	Yes	• Employees from each facility meet to discuss safety and operations issues. • Joint Health & Safety Committees from all facilities meet monthly to discuss safety and operations issues. • IMP Management Review states requirements for reviewing results. • Safety incidents are reported via Utility Risk Management System (URM).	• Safety and operations meetings have meeting minutes and posted on Connector. • IMP Management Review reports are available to all employees via Connector. • Safety incidents are posted on Connector.		
A3.5	Has the permit holder ensured that resources are planned and provided to develop, implement, and continually improve the IMPF?	Yes	The annual O&M budget cycle allows for resourcing for the execution of accountabilities as stated in the various IMP standards relevant to LNG facilities. Resourcing is discussed at the IMP Management Review meetings.	• IMP Management Review (CRL 1075)		
A4	**Goals and Objectives**					
A4.1	Has the permit holder's senior management established goals and objectives for its IMPF?	Yes	Integrity Management Policy (CRL 1021) contains high-level goals and objectives for all gas system assets, including LNG facilities.	• Integrity Management Policy (CRL 1021)		
A4.2	Are the objectives of the IMPF consistent with the overall safety policies and objectives (corporate direction)?	Yes	The objectives of the Integrity Management Policy (CRL 1021) align with the Safety and Environment Policy (CRL 1032).	• Safety and Environment Policy (CRL 1032) • Integrity Management Policy (CRL 1021)		
A4.3	Are the objectives and targets measurable, and do they link to key performance indicators (KPI)?	Yes	High-level objectives and targets are measureable. They are a key component of the IMP Management Review process, which includes the production and review of dashboards.	• Integrity Management Policy (CRL 1021) • IMP Management Review (CRL 1075)		
A5	**Performance Measurement and Analysis of Data**					
A5.1	Has the permit holder established and maintained a documented process to identify metrics or key performance indicators (KPIs) to measure the effectiveness of its risk management and the effectiveness and adequacy of its IMPF?	Yes	KPIs are created and reviewed per requirements of IMP Management Review (CRL 1075), which applies to all gas system assets, including LNG facilities.	• IMP Management Review (CRL 1075)		
A5.2	Has the permit holder established and maintained both leading and lagging KPIs?	Yes	Lagging indicators include: • Number of failure incidents • Corrective work management Leading indicators include: • Preventative maintenance work, including inspections and overhauls The LNG Operations Department reviews financial, safety and tank level results monthly.	Minutes are kept for monthly safety and operations meetings. IMP Activity dashboards for: • Preventative Maintenance Programs • Corrective Work Management		
A5.3	Include a description of quantifiable objectives, targets, and key performance indicators (KPIs).					

Per Integrity Management Policy (CRL 1021) and reviewed per IMP Management Review (CRL 1075). Dashboards are produced quarterly and formal reviews are conducted twice per year.

*FEI strives to have zero failure incidents** or other incidents involving the functionality of the gas system assets that could lead to any of the following Significant Consequences:*

- *Safety: death or serious injury to a person (employee, contractor, customer or public); and/or*
- *Environment: an estimated irreversible, long-term, or continuous change to the ambient environment in a manner that causes harm to human life, wildlife, or vegetation; and/or*
- *Service Disruption: outages that impact a large number of customers.*

***A failure incident is defined as "an unplanned release of service fluid"*

The following are targets and key performance indicators related to the objective:

IMP DOCUMENT	GOALS/OBJECTIVES	PERFORMANCE INDICATOR	TARGET	RATING SCALE
Policy 1021	To strive for zero failure incidents** or other incidents involving the functionality of the gas system assets that could lead to any of the following significant consequences*: ***Safety:** death or serious injury to a person (employee, contractor, customer or public); ***Environment:** irreversible, long-term, or continuous change to the ambient environment in a manner that causes harm to human life, wildlife, or vegetation; ***Service Disruption:** outages that impact a large number of customers. ***A failure incident is defined as "an unplanned release of service fluid"*	***Safety:** # of failure incidents that resulted in death or serious injury to a person (employee, contractor, customer or public)	0	G: 0 R: ≥ 1
		***Environment:** # of failure incidents that resulted in externally reportable gas system asset Incidents with environmental impacts (per CRL 1127)	0	G: 0 R: ≥ 1
		***Service Disruption:** # of failure incidents that resulted in greater than 10,000 customers interrupted.	0	G: 0 R: ≥ 1

Completion of preventative maintenance and corrective work orders is included for IMP Preventative Maintenance Programs and Corrective Work Management Activity dashboards.

The company posts safety statistics monthly on Connector, which is available to all employees. The company scorecard includes "all injury frequency rate" which has a 2017 goal of 2.21.

Monthly workgroup safety meetings review LNG Department safety statistics (injuries, near misses and vehicle accidents).

A5.4	Do the KPIs for the facilities, and associated equipment, include tracking completion of scheduled facility integrity inspections to prevent harm to employees, the public, the environment, and the property?	Yes	SAP PM orders and associated status reports are used to manage scheduled inspections.	• Sample SAP order status report.		
A5.5	Has the permit holder established and maintained a process for periodically reviewing, evaluating and trending facility performance through relevant Key Performance Indicators (KPI)?	Yes	IMP Management Review (CRL 1075) requires the quarterly production of dashboards and the formal review of those dashboards twice per year.	• IMP Management Review (CRL 1075)		
A5.6	Are the KPIs updated as required?	Yes	IMP Management Review (CRL 1075) requires the quarterly production of dashboards and the formal review of those dashboards twice per year.	• IMP Management Review (CRL 1075)		
A6	**Management Review**					
A6.1	Has the permit holder reviewed the IMPF to determine the extent to which the performance goals and objectives have been met?	Yes	IMP Management Review (CRL 1075) requires the quarterly production of dashboards and the formal review of those dashboards twice per year.	• IMP Management Review (CRL 1075)		
A6.2	Has senior leadership formally reviewed the adequacy, implementation and effectiveness of its integrity management program for facilities?	Yes	Accountabilities listed in IMP Management Review (CRL 1075): • Exec VP, Operations & Engineering • Director, Engineering Services	• IMP Management Review (CRL 1075)		
A6.3	Is the management review process formal and documented, and does it occur on a regular basis?	Yes	Per IMP Management Review (CRL 1075), meeting invites are sent out and meeting minutes are filed in FileNet	• IMP Management Review (CRL 1075)		

			(records repository). The meetings are held twice per year.	• FileNet		
A6.4	Does the management review focus on evaluating the adequacy and effectiveness of the IMPF to meet its stated goals and targets (through review of key performance indicators), implementation of the IMFP, compliance to company and regulatory requirements, and identification of corrective actions for continual improvement?	Yes	See above responses regarding KPIs. Regulatory requirements are documented in the Integrity Management Program (CRL 1056). The requirements for corrective actions and continual improvements are documented in IMP: CA CI Management (CRL 1085).	• Integrity Management Program (CRL 1056) • IMP: CA CI Management (CRL 1085)		
A6.5	Outline the inputs of the management review process and describe how these inputs are considered in the process.					
	These are described in Section 3 of IMP Management Review (CRL1075).					
A6.6	Do the outputs from the management review include a summary of assessment of the effectiveness of the IMPF and risk management process?	Yes	A formal report is completed after the two IMP reviews that are conducted each year. This report is filed into FileNet (records repository) per IMP Management Review (CRL 1075).	• IMP Management Review (CRL 1075) • FileNet		
A6.7	Do the outputs from the management review include decisions and actions?	Yes	Per IMP Management Review (CRL 1075), all action items raised during IMP Management Review Meetings are documented in the IMP Management Review Report. In addition, Corrective Actions (CA) arising from IMP Management Review meetings are managed per IMP CA CI Management (CRL 1085).	• IMP Management Review (CRL 1075) • IMP: CA CI Management (CRL 1085)		
A6.8	Do the outputs from the management review include changes to required resources?	Yes	Yes, if identified as per the IMP Management Review Report, Section 6 Business Planning.			
A6.9	Do the outputs from the management review include improvements to processes and procedures to meet the requirements?	Yes	If that is what was identified during the review.			
A6.10	Has the permit holder ensured that senior management at least annually reviews and approves the output of management reviews, which shall be documented?	Yes	Yes, as per the process outlined in IMP Management Review (CRL 1075)			
B1	**RISK ASSESSMENT AND MANAGEMENT**					
B1.1	Has the permit holder developed a documented process to identify hazards associated with their processes and to evaluate the risk of those processes – to make certain that risks to employees, the public, and the environment are consistently controlled within the permit holder's risk tolerance?	No	Response is "no" as the process is not documented. In general, the design, procurement and construction of LNG assets were done using external resources. General contractors are selected based on their expertise and experience of compliance with the various codes and regulations; and industry practices related to hazard and risk management. Several processes exist to identify hazards during operations, including: • Employees are required to perform a job hazard analysis before commencing work per EHS Hazard Management Program (CRL 1096) • Planned inspections* • Monthly safety and operations meetings • Emergency exercises • Internal audits • Annual budget cycle • Process hazard analysis (PHA) Identified hazards for LNG assets that require follow on work of an O&M nature are recorded in SAP as a "notification". Identified hazards for LNG assets that require follow on work of a capital nature are recorded in C55 for the capital planning process.	• The design, construction and operation details related to the initial design and construction are documented in Plant Manuals for each LNG asset. Copies of these documents are retained at each facility, as well as in FileNet or the S drive. • EHS Hazard Management Program (CRL 1096) • Planned inspections are documented in SAP. • Minutes are prepared for monthly safety meetings (filed on Connector) • Minutes are prepared for monthly operations meetings (filed on S drive) • Corrective actions resulting from emergency exercises are documented. (filed on S drive under the Emergency Department) • Corrective actions arising from internal audits is documented. (Audit Services repository) • IMP Corrective Work Management (CRL 1070) • IMP Capital Management (CRL 1065)	**DEFICIENCY:** A risk assessment and management process does not exist for LNG assets. **CORRECTIVE ACTION:** A documented risk assessment and management process will be developed. Note: Included in the scope of this CA will be other deficiencies related to risk assessment and management identified in other items of this self-assessment.	December 31, 2020

			An Asset Investment Planning program (referred to as "C55") is a software package that is currently being implemented that will allow Asset Management to capture all identified hazards and prioritize the associated risks for capital projects. * Facilities are monitored continuously and inspected on a periodic basis by plant personnel. The frequency for such inspections are based on maintenance practices that are a combination of recommendations from the vendors and experience.			
B1.2	Are the levels of risk broadly tolerable or ALARP, and has the permit holder defined and documented them?	No	Risk matrices adhere to ALARP principles as defined and documented in the risk assessment matrix. Mt. Hayes has a risk matrix describing the levels of risk and identifies areas where risk needs to be mitigated and areas where no further mitigation is necessary. T1A has a matrix defined by the EPC Contractor describing the levels of risk and identifies areas where risk needs to be mitigated and areas where no further mitigation is necessary TIL utilizes the same matrix as Mt. Hayes.	• Risk Assessment Matrix stored on S:\drive • Tilbury 1A Safety & Loss Management Program	**DEFICIENCY:** The definitions for ALARP is not documented. **Note:** The definitions for ALARP will be included in the scope for the CA for item B1.1.	
B1.3	Has the permit holder ensured that risks are reassessed on a periodic basis, or whenever there is a change to facility operation or operating environment that is different than previous risk assessment situations?	Yes	MOC is conducted every time there is a change to the asset. Such changes are identified through inspection, maintenance and monitoring activities. The MOC process includes provision for assessing risks associated with the change.	• Planned inspections are documented in SAP PM. • Minutes are prepared for monthly safety and operations meetings and are filed on Connector and S drive. • Corrective actions resulting from emergency exercises are documented on a list maintained by Emergency Services. • Corrective actions arising from internal audits is documented on a list maintained by Audit Services • Management of Change Procedure Filed on S drive		
B1.4	Has the permit holder applied risk assessment at the early stages of facility development to foster an inherently safer design at lower cost and lower risk?	Yes	The principles of "inherently safer design" have been used by FortisBC. The preference is to implement engineered solutions. The design of each facility meets the codes and regulations at the time of construction or upgrading. Mt. Hayes and Tilbury 1A have had risk assessment at all stages of facility development including early stages of facility development			
B1.5	Has the permit holder ensured that detailed risk assessments are be carried out by personnel (internal or external) who have relevant and certified industry experience and training in carrying out risk assessments?	Yes	All risk assessments that require PHA's are conducted by competent resources. Employees are trained on risk assessments during operations using the Hazard Evaluation Guideline (Appendix to Management of Change). The FEI procurement process assigns work to external resources that have been determined to be competent.			

B2	**Process Knowledge and Information**					
B2.1	Has the permit holder ensured that the facility inventory data is gathered and integrated to support the risk assessment?	Yes	The design, construction and operation details related to the initial design and construction are documented in Plant Manuals for each LNG asset. Copies of these documents are retained in FileNet or S drive. Content includes the items listed in the Protocol document.	• Plant Manuals: FileNet or S drive • All drawings: FileNet		
B2.2	Has the permit holder ensured that all data, from planning to commissioning phases, has been gathered, maintained, and updated, and that relevant information related to mitigation aspects has been passed over to operational and integrity management personnel?	Yes	The design, construction and operation details related to the initial design and construction are documented in Plant Manuals for each LNG asset. Copies of these documents are retained in FileNet or S drive. Content includes the items listed in the Protocol document.	• Plant Manuals: FileNet or S drive • All drawings: FileNet		
B2.3	Has the permit holder ensured that information exists with regards to the processes, material properties, and equipment design for all phases, from safe design, through construction, operation, maintenance, and decommissioning?	No	For Tilbury 1A and Mt Hayes, the design, construction and operation details related to the initial design and construction are documented in Plant Manuals for each LNG asset. Copies of these documents are retained in FileNet or S drive. Content includes the items listed in the Protocol document. Not all information is available for Tilbury Island due to its construction in 1970.	• Plant Manuals: FileNet or S drive • All drawings: FileNet	**DEFICIENCY:** Not all information listed in the protocol document is available for all LNG plants due to the year that they were installed. **Note:** The task to identify material information that is required to effectively implement its integrity management program for all LNG plants; and to develop strategies for the absence of that material information.will be included in the scope for the CA for item B1.1.	
B2.4	Has the permit holder identified the types of facilities and the standards and guidelines (such as API, ASME, CSA, etc.) to which the facilities are designed, constructed, and operated?	Yes	Mt Hayes and Tilbury 1A are designed, constructed and operated in compliance with CSA Z276, as well as regulations per BCOGC and BCTSA. Tilbury Island is operated in compliance with CSA Z276, as well as regulations per BCOGC and BCTSA. Tilbury Island was designed and constructed to NFPA 59A; but recent modifications comply with CSA Z276 since its publication.			
B3	**Hazard Identification**					
B3.1	**Facility Projects**					
B3.1.1	Are hazards and hazardous scenarios identified and documented using appropriate hazard identification techniques for appropriate stages in the design, construction, and start-up of the project/facility before proceeding to the next level?	Yes	In general, the design, procurement and construction of LNG assets were done using external resources. Consultants and vendors were selected based on their expertise and experience of compliance with the various codes and regulations; and industry practices related to hazard and risk management. New LNG assets are designed to CSA Z276. Hazard reviews are conducted and documented for all appropriate stages of the plant lifecycle ~~as follow.~~ For example: • Tilbury Island: HAZOP • Mt Hayes: PHA , HAZOP • Tilbury 1A: HAZID, HAZOP & PSSR	• FileNet • SharePoint		
B3.1.2	Explain how hazards are considered in the hazard identification process. Comment on the systematic hazards identification analysis and explain how it covers the entire facility and all materials, infrastructure, systems and activities.					
	Hazards that are identified during the design and procurement stages are discussed amongst FortisBC stakeholders and the selected consultants /vendors. Hazards are identified during facility projects by using PHA or HAZOP.					
B3.1.3	At the planning stage, has the permit holder assessed hazard and risk associated with the installation phase (using methods such as HAZID, consequence analyses of major credible accident scenarios, and risk criteria)?	Yes	See response to B3.1.1.	• EPC Contractor – Safety in Transition Plan • Management of Change Procedure – LNG Production Facilities		

B3.1.4	Do the siting decisions and plot plans consider the associated hazards and mitigation, such as distance from waterbodies, buffer zones, natural hazards, and transportation related hazards (using methods such as qualitative risk analysis, HAZOPs and determination of safety integrity level requirements, preliminary quantitative risk analysis or detailed consequence assessment)?	Yes	See response to B3.1.1.	• CSA Z276 Sitting Study for the Tilbury 1A Project LNG Facility		
B3.1.5	Does the design process have appropriate reviews and approvals at various design stages (using methods such as detailed Quantitative Risk Assessment (QRA), detailed HAZOPs, vendor HAZOPs, or evacuation analysis)?	Yes	See response to B3.1.1.	• Many reports from Bechtel available upon request		
B3.1.6	Are controls in place to ensure that fabrication, installation, and construction conform to design specifications, standards, and codes?	Yes	For contract work, inspectors (internal or external) are used. For work done by FortisBC resources, technicians, managers and/or engineer of record inspects the work. All design specifications are stamped by a Professional Engineer stating the appropriate standards and codes. All drawings go through an approval process and any deviations from the original design specification requires approval. The fabrication, installation and construction conforms to design specification through the issuance of IFA, IFD, IFC and finally Records Drawings (as-builts).			
B3.1.7	Are controls in place for managing changes to the project scope, design, construction, and approvals?	Yes	In addition to the response for B3.1.1, changes to the project are managed through review and approval of change request documents as part of the FortisBC procurement process.			
B3.1.8	Does the as-built documentation reflect the exact details of the built facility to ensure that integrity issues can be investigated in the future?	Yes	IFC drawings are updated to reflect the exact details of the built facility and stored as either red line or record drawings	• Plant Manuals: FileNet or S drive • All drawings: FileNet		
B3.2	• Process Operations					
B3.2.1	Has the permit holder maintained a process to identify and document hazards associated with their processes and the hazardous scenarios associated with the activities of the facility, resulting from operations, operating environment, and changes to the operating conditions?	Yes	Hazards are identified during scheduled inspections, monitoring and maintenance activities. Depending on the severity, conditions identified as a hazard are discussed with their manager or at shift changeover meetings or operations meetings. Hazards associated with the equipment that require action are reported on SAP notifications. Identified hazards that are not actioned are recorded in the shift log Employees are required to perform a job hazard analysis before commencing work per EHS Hazard Management Program (CRL 1096). Safe Work Planning (CRL 1123) requires employees to identify and manage hazards on a work site. Monthly operations meetings are held to review operating matters and concerns. Employees are expected to review concerns of a pressing matter ASAP to their manager. The MOC process is designed to identify and document hazards associated with the activities of the facility. It is designed to prevent the introduction of unrecognized potential hazards into the facility.	• EHS Hazard Management Program (CRL 1096) • Safe Work Planning (CRL 1123) • Job Aid for "initiating Corrective Work" • Management of Change Procedure – LNG Production Facilities		

B3.2.2	Have methods such as revised QRA, management of change HAZOPs, or revised hazards analyses been applied?	Yes	HAZOP has been applied during initial design and reassessed periodically. MOC is applied to any changes that is made to the facility. Changes are anything other than like-in-kind replacement of existing equipment.	• HAZOP documentation available upon request • Management of Change Procedure – LNG Production Facilities		
B3.2.3	Have facilities and equipment, where potential interaction of hazards can increase risk, been identified?	Yes	Hazards are identified when conducting HAZOP (including reviews), What-if or MOC Check lists.	• HAZOP documentation available upon request • Management of Change Procedure – LNG Production Facilities		
B4	**Risk Assessment**					
B4.1	After having identified all possible hazards and scenarios, has the permit holder assessed the collective hazards and the degree of risk associated with these hazards as a function of likelihood and severity?	Yes	All hazards are assessed for risk and scored for tolerability based on the risk matrix and are actioned based on the need for action.			
B4.2	Explain how risk is determined, either qualitatively or quantitatively, using appropriate techniques, such as, FMEA (Failure modes and effect analysis), FMECA (failure modes, effects and criticality analysis), RCM (reliability-centered maintenance), RBI (risk-based inspection), Fault tree, and Markov analyses.					
	Risk is determined by the combination of the consequence and the likelihood of an undesired event. A Process Hazard Analysis (PHA) is completed utilizing the Hazard and Operability (HAZOP) methodology. The PHA uses a risk ranking system that ranks hazard scenarios according to their estimated severity and likelihood. The risk ranking system accomplishes the ranking by using a Risk Matrix of severity and likelihood. The matrix will define the values of the relative risk for each combination of severity and likelihood. This scoring then provides a guideline that represents the decision to be taken for the applicable risk.					
B4.3	What are the selection criteria for the chosen risk assessment methods (such as availability of data, organizational maturity, goals, and the magnitude of the decision)?					
	All factors are considered in the selection criteria. In general, selection considers the magnitude of the decision. If magnitude is small, a What-if assessment is made, otherwise a HAZOP is selected. The Risk Assessment Matrix will determine the magnitude.					
B5	**Risk Tolerance**					
B5.1	Has the permit holder set criteria for risk tolerance?	Yes	Tilbury 1A's Safety & Loss Management Program, Appendix H (August 31, 2016) establishes the criteria for risk tolerance; and is used for all LNG facilities.	• Tilbury 1A's Safety & Loss Management Program, Appendix H (August 31, 2016)		
B5.2	Are the risk tolerance values relevant and consistent with the policies, goals, and objectives of the IMPF?	Yes		• Integrity Management Policy (CRL 1021) • Tilbury 1A's Safety & Loss Management Program, Appendix H (August 31, 2016)		
B6	**Risk Reduction and Management**					
B6.1	Based on the risk assessment process, has the permit holder prioritized facilities, equipment, and piping?	No	FEI does not prioritize facilities based on the risk assessment process; but does prioritize equipment and piping at specific facilities based on risk assessments. All hazards are assessed using the risk assessment matrix.		**DEFICIENCY:** A process for prioritization of facilities, equipment and piping based on risk assessment process is not documented. **Note:** A process for prioritization of facilities, equipment and piping based on risk assessment process will be included in the scope for the CA for item B1.1.	
B6.2	Has the permit holder implemented risk reduction and control measures to prevent, mitigate, and manage risk where the chosen threshold or tolerance is exceeded?	Yes	All hazards are assessed using the risk assessment matrix.	• IMP Capital Management, (CRL 1065) • Risk Assessment Matrix		
B6.3	Has the permit holder developed a schedule for risk reduction measures?	Yes	Risk reduction measures for risks that exceed the tolerance threshold is by engineering, procedural or administrative solutions. Engineering solutions involving capital expenditures are scheduled via IMP Capital Management (CRL 1065). Other solutions are scheduled by local plant management via the MOC process.			
B6.4	Has the permit holder tracked the implementation of such measures (see previous question) to completion?	Yes	Risk reduction measures for risks that exceed the tolerance threshold is by engineering, procedural or administrative solutions. Engineering solutions involving capital expenditures are tracked via IMP Capital Management (CRL 1065). Other	• PMO tracking spreadsheet		

			solutions are tracked by local plant management via the MOC process.			
B6.5	Does the permit holder review mitigation actions appropriate to their facilities through either engineering, process, or administrative solutions?	Yes				
B7	**Risk Review and Update**					
B7.1	**Risk Assessment Update and Review**					
B7.1.1	Explain the process for risk assessment updates, how often risk assessments are reviewed, and describe the circumstances that would trigger an update of the risk assessment.					
	All hazards are assessed and reduced to ALARP. All plant hazards are reviewed on a five-year cycle. Between the five-year cycle reviews, the MOC process is used. Risk assessments are updated when conditions change, as required, such as: • Service requirements for existing equipment (flows, pressures, etc.) • When inspection results show deterioration of condition of piping or equipment • If there is a change to the risk matrix • Corrective actions arising out of investigations, audits, etc. • New equipment					
B7.2	**Risk Management Review**					
B7.2.1	Has the permit holder ensured that risk management results are reviewed at least annually to ensure that risk reduction measures are effective and risk is reduced to an acceptable level?	Yes	Once risk reduction measures are implemented, the subsequent IMM activities will identify if the risk has been reduced or not as most IMM activities have at least an annual frequency.			
C1	**Communication Process**					
C1.1	Has the permit holder established and implemented an effective process for internal and external communication to coordinate information essential to the IMPF?	Yes	Shift changeover meetings and operational meetings are used to involve staff. IMP Management Review is being developed for reviewing KPI's for LNG assets. Maintenance records are available from SAP. Training records are available from the Training Dept. Processes are in place to notify the BCOGC, BCTSA, BCFLNRO and BCUC of integrity related incidents relevant to their regulatory authority. Processes are in place to file information required as part of permits to BCTSA (pressure vessel inspections) and BCFLNRO (emission reports). Internally, the following are conducted: • • Employees from all LNG JHSC meet monthly to discuss safety and operations issues. • Employees from each LNG facility meet monthly in person to discuss safety and operations issues. • IMP Management Review states requirements for reviewing IMP performance results with key stakeholders. • Safety incidents are reported via URM.	• Safety and operations meetings have meeting minutes and posted on Connector. • IMP Management Review reports are available to all employees via Connector. • Safety incidents are posted on Connector.		
D1	**Organizational Structure, Roles and Responsibilities**					

D1.1	Does the IMPF include a suitable organizational structure, with well-defined responsibilities and authorities to establish and maintain an effective IMPF?	No	The various roles that are involved with the IMP-F is not specifically documented for LNG assets, e.g. the various roles within Asset Management and Design Engineering. The organizational structure is documented on Connector. High-level accountabilities are covered in Integrity Management Program (CRL 1056). Roles are defined in job descriptions.	• Org charts (Connector) • Integrity Management Program (CRL 1056) • Job descriptions (HR records)	**DEFICIENCY:** The various roles that are involved with the IMP-F is not specifically documented for LNG assets, e.g. the various roles within Asset Management and Design Engineering. **Note:** Descriptions for roles involving the IMPF for LNG assets will be included in the scope for the CA for item A1.1.	
D1.2	Has the permit holder effectively conveyed the key responsibilities of managers and supervisors with regards to their roles within the IMPF?	No	Refer to response for D1.1		**DEFICIENCY:** The various roles that are involved with the IMP-F is not specifically documented for LNG assets, e.g. the various roles within Asset Management and Design Engineering. **Note:** The communication of the descriptions for roles involving the IMPF for LNG assets will be included in the scope for the CA for item A1.1.	
D1.3	Does the integrity management program involve personnel within a facility's maintenance, operations, and engineering departments?	Yes	Monthly staff meetings are held to discuss safety and integrity topics. These meetings minutes are kept.	• Monthly meeting minutes		
D1.4	How do the defined responsibilities of managers and supervisors ensure that: - knowledgeable personnel are performing appropriate activities using effective engineering and decision-making tools and methods; - IMPF activities, such as inspections, are being executed and managed as planned; and - appropriate controls are implemented and maintained within the integrity management system for all related activities?					
	Clear roles and responsibilities have not been documented for LNG assets, however in general, - Responsibilities are defined in job descriptions and Integrity Management Program (CRL 1056). - Training and competency program is intended to provide knowledgeable personnel - Employees work their way thru a competency based progression as an LNG Operator - Monthly safety and integrity meetings with staff address employee and management issues and concerns. - Inspections, etc. are performed in accordance with SAP maintenance plans; which are reviewed by managers for completeness on a regular basis. Preventative and corrective work is tracked and managed via SAP orders.					
E1	**Training and Competency**					
E1.1	Has the permit holder established, implemented, and maintained a process for evaluating required competency and training programs for employees, as well as contractors responsible for managing the asset integrity of facilities?	No	A competency management program is being developed for Tilbury 1A plant operators. Competency management programs for Mt. Hayes and Tilbury Island will be developed after T1A. Refer to E1.5 for the selection of contractors.		**DEFICIENCY:** An LNG Operator competency management program is in place but requires updating due to the addition of new assets and operational requirements. **CORRECTIVE ACTION:** The competency management program for LNG Operators will be reviewed, updated and documented.	December 31, 2020
E1.2	Are training schedules and frequency maintained for all identified critical tasks by developing a training matrix for employees?	No	Identified critical task have not been developed. Mandatory training (corporate level, EHS, etc.) has been identified and scheduled for all Operations personnel, and have stated frequencies (e.g. PPE, fall protection, etc.).	• Competency management program for LNG is currently being worked on which include frequency and schedule requirements	**DEFICIENCY:** The process for maintaining training schedules and frequencies for identified critical tasks requires updating. **Note:** A process for maintaining training schedules and frequencies for identified critical tasks will be included in the scope for the CA for item E1.1.	

E1.3	Does the permit holder have an established and implemented process for verifying that employees and other persons working with, or on behalf of, the permit holder are trained and competent to perform their duties in a safe manner?	No	The LNG Operator development and certification program is outdated. Employee training: Training Department records all training for the company. Employee competency: - Probationary reviews for new employees and employees new to jobs - Technical and Professional Competency of Employees (CRL 1167) - Work Observation Program (CRL 1094) Contractor competency: • Procurement Guidelines (CRL 1089) • Contractor Environment Health & Safety (CRL 1037)		**DEFICIENCY:** The process for verifying employee and contractor's training and competency requires updating. **Note:** A process for verifying employee and contractor's training and competency will be included in the scope for the CA for item E1.1.	
E1.4	Are the methods for collection and maintenance of training records clearly documented?	Yes	Managers provide update information to the Training Department.			
E1.5	Does the permit holder have a process in place to evaluate and select contractors on the basis of ability and qualifications to perform specified duties?	Yes	Procurement Policy (CRL 1054) Procurement Guidelines (CRL 1089). Contractor Environment Health & Safety (CRL 1037)	• Procurement Guidelines (CRL 1089) • Contractor Environment Health & Safety (CRL 1037)		
E1.6	What type of evaluation process is used in the selection of contractors (such as review of safety and environmental policies, procedures, past performance, audits to check ability and qualifications, and work site inspections)?					
	Many contracts are awarded to contractors with whom FortisBC has had direct experience with e.g. vendor for existing equipment. Depending on the amount of dollar value, risk to the organization and complexity of the contract, contractors that are new to FortisBC will be subject to pre-qualification process. Examples of larger projects are Tilbury 1A and Mt Hayes.					
E1.7	Does the permit holder have a process in place to ensure that performance requirements and expectations are defined and communicated to the contractor(s)?	Yes	This is written into the terms and conditions of the contract per Procurement Guidelines (CRL 1089). This responsibility is covered in Contractor Environment Health & Safety (CRL 1037)	• Procurement Guidelines (CRL 1089) • Contractor Environment Health & Safety (CRL 1037)		
E1.8	Does the permit holder have a process in place to monitor and assess the contractors' performance, provide feedback, and ensure that identified deficiencies are resolved?	Yes	All contractors on LNG assets must have a "work permit". This responsibility is covered in Contractor Environment Health & Safety (CRL 1037) Internal resources and/or external contractors are used to monitor performance on a contract-by-contract basis depending on the risk to the organization and/or complexity of the project. The Work Observation Program (CRL 1094) applies to work being conducted by contractors.	• Safe Work Permit Form • Contractor Environment Health & Safety (CRL 1037) • Work Observation Program (CRL 1094)		
F1	**Document and Record Management**					
F1.1	Has the permit holder established, implemented and maintained a process for managing documents and records needed for effective implementation of IMPF activities during different stages of the facility life cycle?	Yes	Guidance is provided in IMP: Gas System Asset Records Management (CRL 1086) and Records Retention Policy (CRL 1878). The Gas Assets Records Table (Connector) provides specific details for what records are to be retained where. The Capital Project Closure Process (Connector) provides the requirements for retaining records for new capital projects. Operation and maintenance records are maintained in SAP.	• IMP: Gas System Asset Records Management (CRL 1086) • Corporate Records Table (Connector) • Capital Project Closure Process (Connector) • Records Retention Policy (CRL 1878) • Engineering Drawing Management Policy (CRL 1168) • Engineering Drawing Management System Manual (CRL 1856) • Engineering Drawing Specification for External Contractors (CRL 1084) Storage locations include: • FileNet (read only access) – backed up daily, follows retention policy		

			The requirements for managing engineering drawings is covered by the Engineering Drawing Management Policy (CRL 1168) and the Engineering Drawing Management System Manual (CRL 1856).	• S drive (restricted access) – backed up daily • Off-site storage • On site • SAP (restricted access to master data) • SharePoint		
F1.2	Does the document and record management process encompass creation, security, updating, retention, retrieval, and deletion of all information and records necessary for effective operation of the IMPF?	Yes	Guidance is provided in IMP: Gas System Asset Records Management (CRL 1086) and Records Retention Policy (CRL 1878).	• IMP: Gas System Asset Records Management (CRL 1086) • Records Retention Policy (CRL 1878)		
F1.3	Have responsibilities for document approval and re-approval been specified?	Yes	Provided in IMP: Gas System Asset Records Management (CRL 1086). Management of Corporate Reference Documents (CRL 1199) provides requirements for policies, standards, specifications, procedures and guidelines. Managing Obligations for Engineers (CRL 1899) provides requirements for approving of engineering documents. Engineering Drawing Management System Manual (CRL 1856) and Engineering Drawing Specifications for Contractors (CRL 1084). Approval of specific documents are covered by specific IMP related activities.			
F1.4	Have appropriate controls been identified to ensure that documents required by the IMPF include revisions and updates?	Yes	Management of Corporate Reference Documents (CRL 1199) provides requirements for policies, standards, specifications, procedures and guidelines. Managing Obligations for Engineers (CRL 1899) provides requirements for approving of engineering documents.			
F1.5	Does the process for records consider responsibilities and procedures for the creation, updating, retention, and deletion of records?	Yes	The Capital Project Closure Process (Connector) provides the requirements for retaining records for design and construction records. Provided in IMP: Gas System Asset Records Management (CRL 1086). Records Retention Policy (CRL 1878). Management of Corporate Reference Documents (CRL 1199) provides requirements for policies, standards, specifications, procedures and guidelines. Managing Obligations for Engineers (CRL 1899) provides requirements for approving of engineering documents.			
F1.6	Does the process for records consider evidence of past activities, events, changes, analyses, and decisions?	Yes				
F1.7	Does the process for records index and describe the types, forms, and locations of records?	No	The Gas System Assets Records Table defines what records are required and where they are to be kept. The Gas System Assets Records Table has not been updated for several years and is not mandated by company standard.		**DEFICIENCY:** The Gas System Assets Records Table has not been updated for several years and is not mandated by company standard. **Note:** The task to update the Gas System Assets Records Table and setup as a company standard will be included in the scope for the	

			MOC process for records includes the Asset Drawing List changes. Historical records have been put into FileNet via Gas Assets Records Project (GARP) and Records Assessment Project (RAP)		CA for item A1.1.	
F1.8	Does the process for records consider retention policy as otherwise required by legal and other applicable requirements?	Yes	Records and Retention Policy CRL 1878	• Records and Retention Policy (CRL 1878)		
F1.9	Does the process for record management consider information related to location, construction records, operating conditions, inspection, testing and maintenance records, and facility incidents?	Yes		• CRL 1086 and all IMP related standards. • All the information is available at different locations: ○ File Net ○ Engineering library ○ S drive ○ Site library ○ SAP ○ URM ○ Iron Mountain		
F1.10	Indicate how incomplete records due to asset transfers (or for other reasons) are managed within the scope of the IMPF. Provide information on how the IMPF manages in the absence of these records, as well as how these records are being recovered.					
	Efforts to find undiscovered records continue. If information is needed from these records, Engineering and Operations determine the next course of action, which could include retesting, equipment replacement, vendor doc, contractor doc, original design docs, etc.					
G1	**Managing Change**					
G1.1	Has the permit holder developed and implemented a systematic process for identifying, evaluating, controlling, and documenting any change to facility design, specifications, operations, standards, organization, or activities and legal requirements?	No	LNG assets have an MOC process to deal with other than like-for-like replacements for those physical assets; but it does not cover managing organizational and procedural changes. IMP: Management of Change (CRL 1173) is a high-level document; but does not provide sufficient level of detail to execute those high-level requirements for specific assets.	• IMP: Management of Change (CRL 1173) • IMP: Industry Awareness (CRL 1172) • IMP: Capital Management (CRL 1065) • Management of Change Procedure – LNG Production Facilities	**DEFICIENCY:** The existing LNG process for MOC does not address organizational and procedural changes. **Note:** The task to develop a process for MOC organizational and procedural changes will be included in the scope for the CA for item A1.1.	
G1.2	How does the permit holder's process for managing change ensure that no unforeseen new hazards are introduced and that the risk of existing hazards to employees, public, or the environment is not unknowingly increased?					
	LNG assets have an MOC process to deal with other than like-for-like replacements for those physical assets. The Management of Change process is designed to prevent the introduction of unrecognized potential hazards into the workplace. When changes are made to facilities, there is the potential for introduction of unrecognized hazards. Through a process of management reviews, engineering reviews and the active participation of facility personnel, unanticipated hazards may be mitigated prior to project completion. Qualified plant personnel review the request to identify any potentially adverse impacts and assign key individuals to develop a detailed design decision that can be safely executed in the plant. Prior to the change being implemented the MOC owner must ensure all qualified plant staff has authorized the MOC design. A hazard evaluation and the applicable hazard assessment must be completed with appropriate authorizations.					
G1.3	Does the process for managing change consider changes that are initiated and controlled by the permit holder?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.			
G1.4	Does the process for managing change consider changes that are not initiated and controlled by the permit holder?	Yes	CRL 1173 provides requirements for such things as regulatory and industry change.			
G1.5	What type of processes are used by the permit holder to manage changes that are initiated and controlled by the permit holder, and those that are not initiated and controlled by the permit holder, and are these processes outlined within the IMPF?					
	Refer to responses to G1.3 and G1.4.					

G1.6	Does the permit holder have a management of change (MOC) process to manage risks related to design changes and modifications to equipment and process?	Yes	LNG assets have an MOC process to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.7	What is the criteria and process for a change to be "replacement in kind"?					
	Replacement in kind is replacement of equipment using the same type, size, design rating and material. Replacement in kind is not subject to MOC.					
G1.8	What type of process is used for managing changes related to end of service requirements to dismantle, decommission, and dispose of equipment, and for operational waste?					
	For pressure vessels, a Pressure Equipment Integrity Manual exists that defines the end of life process. Hazardous and Non-Hazardous Waste Management (CRL 1163) provides specifics for operational and end of service requirements.					
G1.9	Does the MOC process address and/or document the identification process for anticipated and actual change?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.10	Does the MOC process address and/or document what constitutes a change (temporary or permanent), and what falls under replacement in kind (which is not subject to MOC)?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.11	Does the MOC process address and/or document the reasons for change?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.12	Does the MOC process address and/or document the responsibilities and authorities for approving and implementing changes?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	Management of Change Procedure – LNG Production Facilities		
G1.13	Does the MOC process address and/or document the analysis of implications and changes?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.14	Does the MOC process address and/or document the impact and risk of the changes?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.15	Does the MOC process address and/or document the communication method and associated records and documents?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.16	Does the MOC process address and/or document the timing of changes (approval and implementation)?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.17	Does the MOC process address and/or document close outs?	Yes	LNG assets have an MOC process (including required documentation) to deal with other than like-for-like replacements for those physical assets.	• Management of Change Procedure – LNG Production Facilities		
G1.18	Referring to the previous nine questions, comment with regards to any items that are not included within the MOC process.					
	None					
H1	**Operational Controls**					

H1.1	Has the permit holder established and maintained procedures for the safe operation of each facility?	No	Operating manuals and procedures exist for each plant but there is no formal review cycle for updating them.	• Plant Operations Manual (hardcopy, S drive or SharePoint) • Plant operations procedures (on SharePoint or S drive)	**DEFICIENCY:** Operating manuals and procedures exist for each plant but there is no formal review cycle for updating them. **CORRECTIVE ACTION:** A process will be developed for the maintenance of Plant Operations manuals and job procedures.	December 31, 2020
H1.2	Do the procedures for safe operation address initial start-up (new or modified facilities), normal operation, temporary operation, emergency operation (including shutdowns), normal shutdown, start-up and restoration following maintenance or outages?	No	Operating manuals and procedures exist for each plant but there is no formal review cycle for updating them.	• Plant Operations Manual (hardcopy, S drive or SharePoint) • Plant operations procedures (on SharePoint or S drive)	Refer to H1.1	
H1.3	Are control room management procedures currently in place?	No	Operating manuals and procedures exist for each plant but there is no formal review cycle for updating them.	• Plant Operations Manual (hardcopy, S drive or SharePoint) • Plant operations procedures (on SharePoint or S drive)	Refer to H1.1	
H1.4	Explain how the permit holder ensures that the control room operators have the necessary tools, knowledge, training, and resources available to maintain safe operations of the facilities.					
	Plant operating manuals are located at all sites. Refer to the section on competency for knowledge and training.					
H1.5	Do the operational controls also address risk, hazards, training and communication?	No	The deficiencies identified in B1.1 and E1.1 also apply to operational controls.		**DEFICIENCY:** The deficiencies identified in B1.1 and E1.1 apply to operational controls. **Note:** Developing content for operational controls will be included in the scope for the CA for item B1.1. **Note:** Developing content for operational controls will be included in the scope for the CA for item E1.1.	
H1.6	How does the permit holder ensure that its facilities have inherently safer designs?					
	FEI informally considers inherently safer designs during the conceptual design phase for new assets.					
H1.7	What type of controls are used to ensure that facilities are manufactured, fabricated, and installed consistent with applicable requirements, regulations, and standards?					
	For larger projects, contractors / vendors are required to state that project meet current regulatory / legal requirements. CRN numbers are obtained for pressure vessels per the Pressure Equipment Integrity Manual Rotating equipment is stamped by vendor regarding inspection. Regulatory approvals are obtained and processes followed. Inspectors are used as required.					
H1.8	What type of controls are used to ensure quality control procedures are maintained for materials and construction?					
	The Pressure Equipment Integrity Manual states the quality control procedures for pressure equipment and piping. CRN numbers are obtained for pressure vessels. Inspectors are used as required.					
H1.9	What type of controls are used to ensure inspection and construction inspection procedures and records are maintained?					
	The Capital Project Closing Process has provisions for inspection records. Records Retention Policy (CRL 1878) states the requirements for these types of records.					
I1	**Inspection, Monitoring and Maintenance**					

I1.1	Has the permit holder documented and maintained inspection, monitoring, and maintenance programs that are appropriate for its facilities and are in accordance with the risk assessment process?	No	An ad hoc, qualitative risk based process has been used for developing IMM programs. Note: The term "ad hoc" is intended to convey the concept of a process that is designed for a specific problem or task that is not intended to be able to be adapted to other purposes; and is conducted on an as-needed basis. This term and intended concept is used in several places in this document. FortisBC has inspection and maintenance programs that have been used based on historical experience. The manufacturer who supplied the LNG equipment have the inspection and maintenance programs defined in each of the plant manuals and is used a starting point, with revisions made based on further information. Inspection and PM orders are created and tracked to completion using SAP PM.	• Plant manuals are hard copy documents that are located on site • Inspection and PM orders are documented in SAP PM.	**DEFICIENCY:** A risk assessment process has not been used for developing IMM programs. **Note:** A risk assessment process for developing IMM programs will be included in the scope for the CA for item B1.1.	
I1.2	Does the selection of inspection, monitoring, and maintenance (IMM) activities ensure that new hazards are not introduced and inspection and monitoring activities follow specific regulations, standards, and codes?	No	The key elements of IMM activities are not documented in CRL or other repositories. Specific IMM activities for specific assets are currently planned and executed in SAP PM. The manufacturer who supplied the LNG equipment have the inspection and maintenance programs defined in each of the station manuals and is used a starting point, with revisions made based on further information.		**DEFICIENCY:** The key elements of the various IMM activities are not documented. **Note:** The key elements of the various IMM activities will be included in the scope for the CA for item B1.1.	
I1.3	What parameters (such as risk assessment results, effectiveness of inspection method and technology, previous integrity reviews, incident history, insufficient documentation, evaluation of anomalies, time dependent consideration, current state of facility/equipment, and industry data) are considered in the planning, scheduling, and frequency determination of IMM activities?					
	All of the above. Examples include: - Previous integrity reviews: borescope results send to manufacturer and frequencies adjusted - Oil analysis: Sent to a lab for analysis; and adjusted frequencies based on condition of oil - Vibration monitoring - Service bulletins from manufacturers: can be for information or mandatory requirements - Pressure vessel inspections - Corrosion programs					
I1.4	Explain how the permit holder ensures IMM activities are tracked, and carried out using appropriate methods for facilities, such as pump stations, compressor stations, metering stations, mainline valve yards, and tank farms. During the assessment meeting the permit holders will be required to present the types of facilities, the total number of facilities operated, total number of planned IMM activities vs carried out in the last calendar year, and the standards relevant for each IMM activity.					
	SAP PM is used to track the completion and recording of IMM activities. SAP PM produces status reports that are used by Operations Managers to monitor completion of the IMM activities.					
I1.5	Has the permit holder ensured that the results of its IMM activities are integrated with data for its risk assessment and performance measures?	No	Refer to the response for I1.1.	• Plant manuals are hard copy documents that are located on site. • Inspection and PM orders are documented in SAP PM.	**DEFICIENCY:** A process to ensure that the results of its IMM activities are integrated with data for its risk assessment and performance measures is not documented. **Note:** A process to ensure that the results of its IMM activities are integrated with data for its risk assessment and performance measures will be included in the scope for the CA for item B1.1.	
I1.6	Have the IMM procedures been effectively communicated to the permit holder's employees?	Yes	IMM procedures are included in the assignment of work to specific LNG Operations personnel. SAP PM orders in many cases refer to specific work procedures stated in them.	• SAP PM orders in many cases refer to specific work procedures stated in them. Can we provide examples? • Maintenance procedures (S drive or imbedded in some SAP PM orders)		
J1	**Evaluation and Fitness-for-Service Assessment**					
J1.1	If any anomalies are identified through the execution of IMPF activities, what type of further inspections are undertaken, and what types of Engineering Assessments (such as FFS) are carried out?					
	All anomalies identified are corrected using SAP. If that anomaly requires change, the MOC process is used and EA or FFS is carried out as appropriate.					

K	**Modification and Repair**					
K1.1	What is the permit holder's process for carrying out modifications and repairs?					
	Depending on the identified modification or repair, they are entered as an SAP notification that requires further assessment via the IMP: Capital Management (CRL 1065) process; or a corrective work order is created for non-capital work. Modifications, not deemed a "replacement in kind", utilize the MOC process. All modifications and capital repairs are tracked, recorded and analyzed (ad hoc) on SAP or via the Capital Project Closing Process. Non-capital repairs are tracked, recorded and analyzed (ad hoc) on SAP.					
K1.2	Has repair methodology been documented in situations where there is a need to execute a repair?	Yes	Equipment manufacturers provide repair procedures for their equipment. Upon request, oversite of the repairs may be provided by the manufacturer. For all other situations, repair procedures are developed, as required.	• Written Work Procedures (CRL 1574).		
L1	**Incident/Near-miss Investigation and Learning**					
L1.1	Has the permit holder documented and implemented its process to report and investigate any hazards, potential hazards, incidents or near misses, and incidents affecting or having the potential to affect the integrity of their facilities?	Yes	Personnel have been instructed to report all incidents and near misses. Managers use discretion as to whether to enter them in URM and/or SAP. Investigations are handled through URM or IMP: Learning from Gas System Incidents (CRL 1076), IMP: Learning from Gas System Asset Incidents (CRL 1076) is currently undergoing an extensive review to increase its effectiveness and awareness.	• EHS Event Analysis Program (CRL 1090) • IMP: Learning from Gas System Asset Incidents (CRL 1076)		
L1.2	Has the permit holder established, implemented and maintained a process for incorporating findings from incidents and near-misses into standards, procedures, and processes to mitigate systematic development of similar circumstances and to improve the effectiveness of the IMPF?	Yes	Processes for incorporating findings are imbedded in URM and IMP: Learning from Gas System Incidents (CRL 1076),			
L1.3	Has the permit holder maintained and communicated, as necessary, records of investigations?	Yes	Communication findings is imbedded in EHS Event Analysis Program (CRL 1090) and IMP: Learning from Gas System Asset Incidents (CRL 1076). Incidents are reviewed at staff meetings and/or safety meetings; which have minutes produced.	• EHS Event Analysis Program (CRL 1090) • IMP: Learning from Gas System Asset Incidents (CRL 1076)		
L1.4	Has the permit holder reviewed all mitigation/repair corrections resulting from near misses and incidents that are applied to local facilities for applicability to a broader scope (either geographically or by equipment type)?	Yes	All incidents experienced at one facility are shared with the other plants via email, phone calls or meetings.			
M1	**Control of Non-conformance**					

M1.1	Has the permit holder established and implemented a process to regularly monitor and measure the conformance of its processes to the requirements of its IMPF?	Yes	The Work Observation Program (CRL 1094) monitors employees for conformance to processes. Internal Audit Department conducts audits on a periodic basis to validate conformance to processes. External bodies periodically conduct or require audits, inspections and/or self-assessments, e.g. BCSA, OGC, WorkSafeBC, etc.	• Work Observation Program (CRL 1094) • Internal Audit (see section N1)		
M1.2	Has the permit holder defined responsibility and authority for handling and investigating non-conformances, taken action to mitigate any impacts, and initiated and completed corrective and preventive actions?	Yes	Corrective actions arising out of URM based events have responsibilities defined in EHS Event Analysis Program (CRL 1090). Corrective actions arising out of incidents within the scope of IMP: Learning from Gas System Asset Incidents (CRL 1076) have responsibilities defined in that standard. Corrective actions arising out of IMP: Audits and Assessments (CRL 1201) have responsibilities defined in that standard. Corrective actions arising out of IMP Management Review (CRL 1075) have responsibilities defined in that standard. Corrective actions arising out of Work Observation Program (CRL 1094) do not have responsibilities specifically defined.	• Work Observation Program (CRL 1094) • EHS Event Analysis Program (CRL 1090) • IMP: Learning from Gas System Asset Incidents (CRL 1076) • IMP: Audits and Assessments (CRL 1201) • IMP Management Review (CRL 1075)		
N1	**Internal Audits**					
N1.1	Has the permit holder developed and implemented a process for auditing its IMPF?	No	As there is not a fully documented IMPF for LNG assets (per response to A1.1), the response is “no”. The general requirements for audits of IMP’s is contained in IMP: Audits and Assessments (CRL 1201). Elements involving preventative maintenance and corrective work for LNG assets have been audited in recent years.	• IMP: Audits and Assessments (CRL 1201)	**DEFICIENCY:** Audit requirements for the LNG asset IMPF do not exist. **Note:** Audit requirements for the LNG asset IMPF will be included in the scope for the CA for item A1.1.	
N1.2	Does the permit holder’s process define the responsibilities, scope, objectives, frequency, and schedule for internal audits?	Yes	This is covered in IMP: Audits and Assessments (CRL 1201)	• IMP: Audits and Assessments (CRL 1201)		
N1.3	Has the permit holder outlined the process for completing corrective and preventive actions for non-conformances identified through internal audits?	Yes	This is covered in IMP: Audits and Assessments (CRL 1201)	• IMP: Audits and Assessments (CRL 1201)		
N1.4	Does the process ensure auditor competency and independence?	Yes	IMP: Audits and Assessments (CRL 1201)	• IMP: Audits and Assessments (CRL 1201)		

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May 3, 2019

Submitted via e-mail to: Bushra.Waheed@bcogc.ca

Bushra Waheed, PhD., P.Eng.
Integrity Engineer
Energy Infrastructure and Integrity
BC Oil and Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: FortisBC Energy Inc. (FEI) Draft IMPF LNG and Compression Audit reports

Dear Bushra,

In response to your email received on April 12, 2019, entitled "FEI Draft IMP-F LNG and Compression Audit Reports", FEI confirms its acceptance of the findings captured by the BC Oil & Gas Commission (BC OGC), for the following facilities:

1. LNG processing plants
2. Compressor stations

FEI acknowledges that permit holders are required by the BC OGC to develop, implement, and maintain an integrity management program for facilities (IMP-F) to anticipate, prevent, mitigate, and manage risks over the entire life cycle of the facility, to reduce incidents, and to ensure safe, environmentally responsible and reliable operation of the asset. FEI also notes that an IMP-F is mandated in the Pipeline Regulation and Liquefied Natural Gas Facility Regulation, as applicable.

FEI's historical performance demonstrates that it is a safe and prudent operator. FEI has considered that its practices are compliant and meet the intent of regulations and standards and "partially compliant" to the Compliance Assurance Protocol requirements. Therefore, FEI's acceptance of BC OGC assessments of "non-compliant" to the Compliance Assurance Protocol should not be interpreted as FEI not having sufficient controls in place for the assessment and management of risks over the life cycle of its facilities, or that it is not adequately ensuring the safe, environmentally responsible and reliable operation of its assets.

Sincerely,

Paul Chernikhowsky, P.Eng.
Director, Integrity Management and Damage Prevention

FortisBC Energy Inc.

cc: Marko Aaltomaa, Director, Generation and Compression
Darren Julyan, Director, Gas Plant Operations & PMO

Final

Compliance Assurance Report for Facilities Integrity Management Program LNG Production Assets

FortisBC Energy Inc.

May 14, 2019

Permit Holder and Audit Information

Permit Holder Name	FortisBC Energy Inc. (FEI)
Permit Holder address	16705 Fraser Highway, Surrey, BC
Self-Assessment Submission Date	November 30, 2017
Audit date	October 23-24, 2018
Location	FortisBC Head Office Surrey (October 23, 2019), Field visit to Compressors Station and Tilbury plant (October 24, 2019 pm)
Primary Contact	Paul Chernikhowsky
Permit Holder Key Representatives	
Paul Chernikhowsky	Director, Engineering Services
Janet Green	John Byers
Parisa Valipour	Keith Recsky
Darren Julyan	Anindo Dey
Neville Banak	
BCOGC Audit team	
Bushra Waheed	Lead Auditor (QMS)
Umair Hassan	Facilities Engineer
 BCOGC Signature	May 14, 2019 Submission date

1. Compliance Assurance Process – Facility Integrity Management Program

The BC Oil and Gas Commission (Commission) expects the permit holders under its jurisdiction to anticipate, prevent, mitigate, and manage the risks that can adversely affect safety and the environment. Facility permit holders are expected to have a management system-based documented program, such as an Integrity Management Program, for managing asset integrity throughout the lifecycle of their facility assets.

In February 2017, the Commission finalized its new compliance assurance process for monitoring permit holders' integrity management programs for facilities (IMPF). Before issuing this requirement, the Commission was involved in a year-long consultation with industry and relevant regulators, including Technical Safety BC. The Commission's scope and expectations are detailed in a guideline document, called Compliance Assurance Protocol - Integrity management Program for Facilities, available on the Commission's website.

The regulatory requirements for IMPFs are based on the Oil and Gas Activities Act; Drilling & Production Regulation (DPR Section 78.1); Liquefied Natural Gas Facility Regulation, and CSA Z662 (for more details, refer to the Introduction of the Commission's Compliance Assurance Protocol for Integrity Management Programs for Facilities).

Permit holders were notified of their selection to participate in the Commission's compliance assurance process for IMPFs in January 2018. Permit holders were required to complete and submit a Self-Assessment Reporting Document prior to their compliance audit with the Commission. The Commission reviewed the submitted Self-Assessment Reporting Document, and compliance and incident history of the permit holder as available in the Commission's internal database. The Commission also reviewed IMP-related documentation and manuals submitted by the permit holder prior to the audit.

The audit entailed confirmation of the scope of the compliance assurance process and systematic review of processes, records, and documents to verify compliance against 15 IMPF components outlined in the IMPF Compliance Assurance Protocol. Findings for each component determined during the audit were confirmed and debriefed at the end of the audit to the permit holder.

2. Audit Summary

FortisBC Energy Inc. (FEI) owns 3 LNG peak shaving facilities in BC: Tilbury 1 Base (1970), Tilbury 1A (in progress), and Mt Hayes (2011). The Commission conducted the office based compliance audit of FEI's Facilities Integrity Management Program on October 23, 2018 at FEI's head office in Surrey. On October 24, 2018, the auditors visited the LNG Tilbury 1 Base (B-073-H/092-G-03 001) peak shaving facility in Delta.

The purpose of the audit was to provide a holistic review of FEI's management program for its compression and LNG facilities. This report focuses on the IMPF audit for the LNG facilities. Tilbury 1 Base has a simple cryogenic process that involves purification, liquefaction, refrigerant storage tanks, LNG storage, vaporization, boil off compressor and cooler and truck loading. Tilbury 1 Base has undergone a variety of changes including the changes to improve the seismic performance of this facility.

Non-compliance findings identified during the audit that require program and procedural updates are listed in Table 1. All non-compliances must be addressed within a Corrective Action Plan (CAP) developed by FEI and submitted to the Commission. Additional details regarding the Corrective Action Plan submission are provided in Section 4 of this report.

Table 1: List of Non-compliance findings

IMPF Components (as per Compliance Assurance Protocol)	Comments
1.1 General IMPF	*Requirement/Expectation: The general IMP for facilities (IMPF) component requires that permit holders document, establish and maintain the IMPF, and ensure the effectiveness of the IMPF. The permit holders shall clearly identify the facilities/equipment, and the processes managed under the IMPF.* FEI provided the draft IMPF- LNG manual for all LNG assets and the pressure equipment Integrity manual for the Mt. Hayes storage facility and Tilbury LNG facility. FEI intends to follow PSM approach in developing and implementing IMPF for LNG. Expected completion of both manuals is in 2019. In order to comply with all the requirements and expectations of Commission's Compliance Assurance Protocol for Facilities, FEI is required to ensure that its Integrity management program for LNG facilities is developed to • encompass all applicable facility assets, existing programs, processes, practices, data and documents, • clearly define the scope of facilities and equipment managed directly by the IMPF document and those managed through other programs/systems and documents,

IMPF Components (as per Compliance Assurance Protocol)	Comments
	• provide references to existing programs, processes and databases where appropriate within the IMPF and allow any existing programs and prescribed equipment management programs to exist with the appropriate linkages to the IMPF, • incorporate programs/processes with appropriate references for: o pressure vessels, o facility piping, o fixed, rotating and hydraulic equipment, o aboveground and belowground storage tanks, o electrical control, o instrumentation and control (measurement), o structural and mechanical systems, o fire and safety, and o elevating devices and cranes. • include the following plans and programs with appropriate references: o fugitive emissions management related to flanges and other emission sources in accordance with DPR section 41(5), o security management, and o emergency response in accordance with the Commission's Emergency Management Regulation. • maintain records of formal roll out. FEI must ensure that LNG Regulation, CSA Z276 and other relevant standards as appropriate are considered in developing IMPF for LNG assets. FEI must address the development and implementation of its LNG IMPF through a Corrective Action Plan (CAP). The CAP must outline the timeline for development of the IMPF and implementation timelines must be outlined separately for FEI's three LNG facilities.
2.0 Risk Assessment and Management 2.1 Process Knowledge and Information 2.2.1 Hazard Identification: Facility Projects 2.2.2 Process Operations 2.3 Risk Assessment 2.4 Risk Tolerance	*Requirement/Expectation: Risk Assessment and Management subcomponent requires the permit holder to document a process for identifying hazard and evaluating risk to ensure safety of their employees, the public and the environment. The permit holder must apply risk assessment at the early stages of facility development to foster an inherently safer design at lower cost and lower risk. Facility inventory data and licensing information is updated.* FEI mentioned that Mt Hayes and Tilbury 1A are designed, constructed and operated in compliance with CSA Z276, as well as BCOGC and TSBC regulations. Tilbury 1 Base was designed and constructed to NFPA 59A; but recent modifications comply with CSA Z276; Tilbury 1 Base is operated in compliance with CSA Z276, as well as regulations per BCOGC and TSBC.

IMPF Components (as per Compliance Assurance Protocol)	Comments
2.5 Risk Reduction and Management 2.6 Risk Assessment Update and Review 2.7 Risk Management Review	Risk is determined by the combination of the consequence and the likelihood of an undesired event. It was also noted that for the new LNG facility Tilbury 1A, FEI has a process hazard analysis (PHA) completed using Hazard and Operability (HAZOP) methodology. However, quantitative risk assessment was not carried out for the Tilbury 1A. The HAZOP report from 2013 for Tilbury 1 Base was provided as an audit sample record. The implementation of all recommendations from HAZOP were presented for Tilbury 1 Base. It was noted that all information is not available for Tilbury 1 Base due to its construction in 1970. However, FEI has plans for suspending certain sections of Tilbury 1 Base and updating the P&IDs and carrying out a new HAZOP. It was also determined that FEI does not have a documented process for prioritization of facilities, equipment and piping based on risk assessment process. For the risk assessment, FEI was developing RAMs, which was at its conceptual phase at the time of the audit. This will provide a starting point for the reliability centered maintenance (RCM). This concept and process was being piloted for all aspects of the operations of Tilbury 1A. The intent was to implement it to other LNG assets in the future. FEI must take appropriate actions to ensure that a risk assessment management process is developed and implemented that meets the expectation as outlined in the Section 2.0 of Commission's protocol. FEI must address this non-compliance through a Corrective Action Plan (CAP). FEI is recommended to review CSA Z767 process safety standard, API AP 581 and CSA Z276 for guidelines. FEI must continue its efforts to develop and implement a risk assessment process that complies with the entire scope of facilities as per Section 1.1 and Section 2 of the Commission's Protocol for the IMP for facilities. The RA process must ensure that risk management results are reviewed at least annually to ensure that risk reduction measures are effective and risk is reduced to a tolerable level. FEI must address this finding through a Corrective Action Plan (CAP). The CAP must outline the timeline for various actions for risk assessment and management development. Implementation timelines must be outlined separately for each individual LNG facility.

IMPF Components (as per Compliance Assurance Protocol)	Comments
4.0 Communication Process	*The Communication Process component requires that a permit holder establish and implement an effective process for internal and external communication to coordinate information essential to the IMPF.* It was noted that FEI has processes in place for internal and external communication. Communication table for LNG is developed. FEI must address and track how this communication table is implemented through a Corrective Action Plan (CAP).
5.0 Training and competency	*Has the permit holder established, implemented, and maintained a process for evaluating required competency and training programs for employees for managing the asset integrity of facilities?* At the time of the audit, FEI was updating the training and competency program due to the addition of new assets and operational requirements. The existing program was simple and had no process for evaluating the assessors. The process for maintaining training schedules and frequencies for identified critical tasks, control room, and the process for verifying employee and contractor's training and competency required formalization and update. The new training process will focus on training progression levels, detailed competency and qualification process requiring training and testing through exams. It will not only address trades, but also, professional / technical employees, leadership positions, office employees, and contractors. FEI is expected to continue with the development and implementation of the training and competency program for LNG operations. FEI is advised to ensure personnel possess or have access to knowledge, supported through training and competency assessment and assurance on regulations and applicable standards and codes. The commission requires FEI to provide follow up on the implementation of this training and competency process through a Corrective Action Plan (CAP). FEI must outline corrective actions for implementation separately for different LNG facilities.

IMPF Components (as per Compliance Assurance Protocol)	Comments
6.0 Document and Record management	*Requirement/Expectation: Document and Records Management component requires that a permit holder establish, implement and maintain a process for managing documents and records needed for the effective implementation of IMPF activities during different stages of the facility life cycle, e.g., design, material selection, purchasing, construction, operation, maintenance, and decommissioning.* At the time of the audit, FEI was updating its document control and record management process for better data management. The responsibilities for approval and re-approval of documents, creation, update, retention and deletion of records were being revised. During the field visit of the Tilbury 1 Base on-site service and valve maintenance shop, it was found that records were not properly managed. It was also noted that PIDs were being recreated for Tilbury 1 Base to reflect the changes over years. FEI is required to address the above gaps through a Corrective Action Plan (CAP).
7.0 Managing Change	*Requirement/Expectation: The Managing Change component requires that a permit holder develop and implement a systematic process for identifying, evaluating, controlling and documenting any change to facility design, specification, operations, standard, organization or activities and legal requirements to ensure that no unforeseen new hazards are introduced and that the risk of existing hazards to employees, public, or the environment is not unknowingly increased.* The MOC process is presented in detail in the draft IMPF manual and it clarifies what constitutes an MOC, temporary and permanent change, and how replacement in kind type of changes are tracked and managed. It applies to organizational, operational changes, which could be initiated internally or externally. The MOC process used for Mt. Hayes is managed separately and the Tilbury 1 Base uses the same program but manages it differently and separately. FEI does not have a central MOC process. Changes are expected in the documented version as IMPF for LNG is developed and finalized. Therefore, FEI must provide the Commission with the update on development and implementation of the MOC process to all LNG facilities through a Corrective Action Plan (CAP).

IMPF Components (as per Compliance Assurance Protocol)	Comments
8.0 Operational control	*Requirement/Expectation: The Operational Controls component requires that permit holders establish and maintain procedures for the safe operation of each facility and address the initial start-up (new or modified facilities), normal operation, temporary operation, emergency operation, including shutdowns, normal shutdown, start-up and restoration following maintenance or outage, identifying operating limits, alarm management and control room operations.* FEI has operating manuals and procedures for each LNG plant and procedures for operational controls were updated and developed as needed. However, it was noted that there is no formal review cycle for updating them. FEI must ensure that operating manual and procedures are reviewed and revised, and rolled out through a systemic process. A process shall be developed for the maintenance of plant operations manuals and job procedures. For the Tilbury 1A LNG facility, FEI is reminded to ensure that all documentation and data provided as a handover process from Bechtel are maintained in a readily accessible format to those who need it the most (e.g., site operators, control room operators and third party operators) to operate the facility safely and effectively, especially in an emergency situation. FEI is required to address the above gaps through a Corrective Action Plan (CAP).
9.0 Inspection, Monitoring and Maintenance	*Requirement/Expectation: Inspection, Monitoring and Maintenance component requires that a permit holder document and maintain inspection, monitoring, and maintenance (IMM) programs that are appropriate for its facilities and are in accordance with the risk assessment process.* At the time of the audit, FEI was integrating its IMM activities with the risk assessment process, which was being developed. It was noted that FEI has adequate arrangements in place for inspection and maintenance programs based on historical experience and manufacturers' defined inspection and maintenance programs as a starting point, with revisions made as needed. An ad hoc (as needed) qualitative risk based process is also used for developing IMM programs for the older LNG facilities. Inspection and preventative maintenance (PM) orders are created and tracked to completion using SAP PM. The reporting process must ensure that operators report any exceptions in detail and it allows attachment of hand written notes and logs as applicable. Also in case of

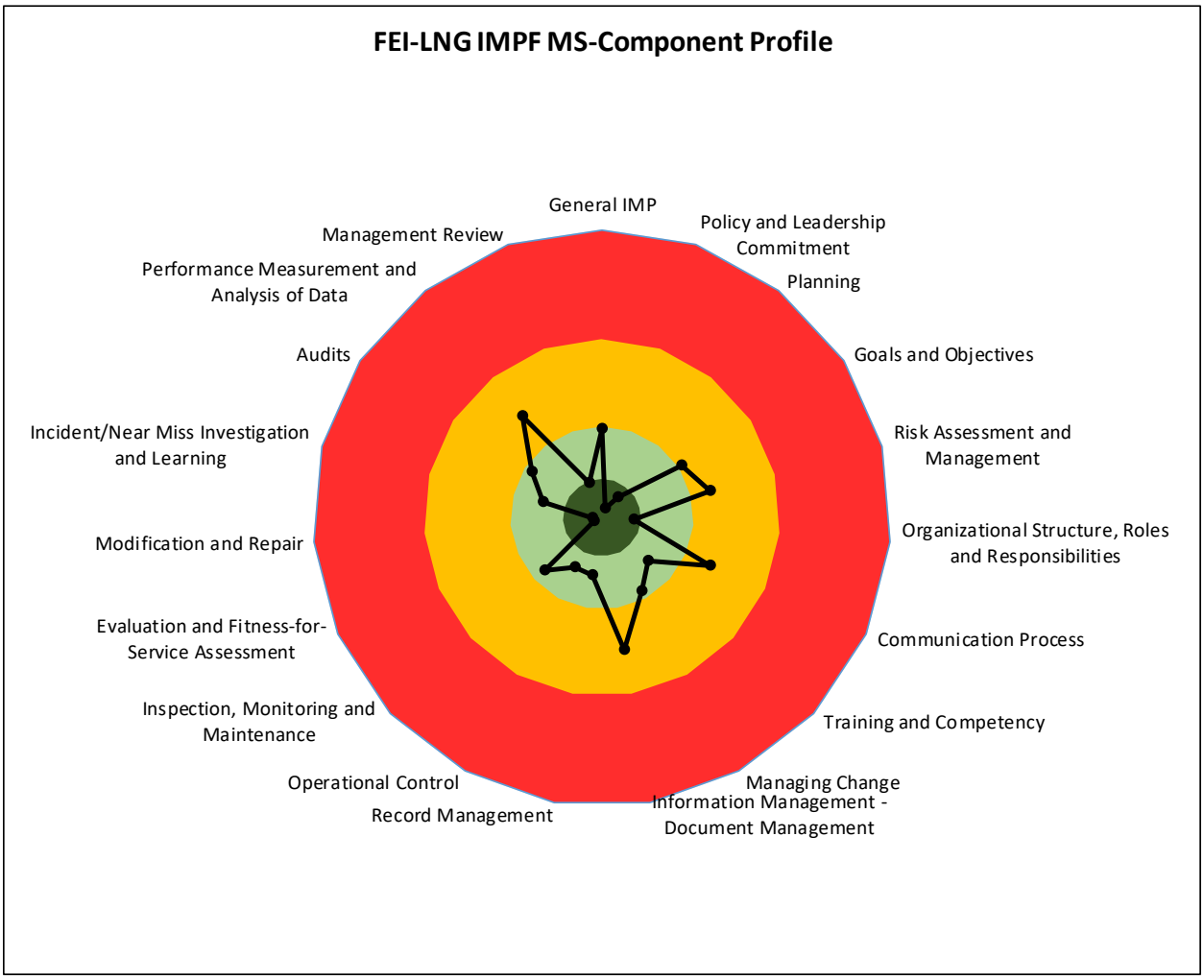
IMPF Components (as per Compliance Assurance Protocol)	Comments
	delays when inspection and maintenance tasks cannot be completed when scheduled, the acceptable risk levels must be mentioned for critical tasks not just indication that task is overdue. Also formal methods and approval of deferring a scheduled task must be established. In order to comply with the requirements of the Commission's Protocol, FEI must develop a process to ensure that IMM activities align with risk assessment process and the results of its IMM activities are integrated with data for its risk assessment and performance measures. FEI must address these findings through a Corrective Action Plan (CAP).
12.0 Incident / Near-miss Investigation and Learning (Same for LNG and Compression)	*Requirement/Expectation: The Incident / Near-miss Investigation and Learning component requires that a permit holder document and implement its process to report and investigate any hazards, potential hazards, incidents or near misses, and incidents affecting or having the potential to affect the integrity of their facilities.* FEI has two different reporting and investigation processes for incidents: URM managed by OHS group and EIR for engineering investigations. The OHS group manages the incident database and communicate the safety report with all incidents. EIRs are reviewed by Engineering from the technical aspect. Incidents can be reported by anyone however, formal documentation of incident reporting is done by supervisors only. Incident investigations are carried out internally by employees trained in taproot. It was noted that FEI has different incentives in place for incident reports and safety. Reporting of near misses is also emphasized. The incidents from all operations LNG or compression are shared and learnings are circulated internally to all to maximize learning from incidents. However, the process and system needs an update. Therefore, FEI is working on finding the right balance of what needs to be investigated and the support systems to maximize the learnings from those incidents. Based on the issues identified above related to inconsistency in incident reporting process, FEI is required to update its incident reporting process, follow process safety approach for incident reporting and investigation, and formalize incident investigation and learning . FEI must also ensure that the updated process incorporates reporting, tracking and trending of near misses and incidents. FEI must address these findings through a Corrective Action Plan (CAP).

IMPF Components (as per Compliance Assurance Protocol)	Comments
13. Performance Measurement and Analysis of Data	*Requirement/Expectation: The Performance Measurement and Analysis of Data component requires that a permit holder establish and maintain a documented process to identify metrics or key performance indicators (KPIs) to measure the effectiveness of its risk management and the effectiveness and adequacy of its IMPF.* FEI has developed a corporate safety policy and goal including the target zero incidents and injury. The objectives of their integrity policy align with FEI's safety and environment policy. KPIs include lagging indicators: number of failure incidents and corrective work management. The leading indicators were not developed yet for the LNG facilities. FEI must provide Commission with revised KPIs and demonstrate how KPIs are reviewed, evaluated and trended to measure the effectiveness of its facility IMP through a Corrective Action Plan (CAP). It was noted that section 3.4 of FEI's draft manual mentions the intention of IMPF as management of hazards and consequence shown by a Bow-tie diagram. It is emphasized that intent of an IMPF is to assess and manage the risks (chance of failure) associated with LNG facility assets resulting from occurrence of events (hazard scenarios) and consequence of such events.
14.0 Internal Audits	*Requirement/Expectation: The Internal Audits component requires that a permit holder develop and implement a process for auditing of its IMPF. A permit holder's process must define the responsibilities, scope, objectives, frequency, and schedule for internal audits. The process for completing corrective and preventive actions for non-conformances identified through internal audits shall be outlined. The process must also ensure auditor competency and independence.* IMPF Audit requirements are outlined in the draft IMPF manual for LNG. It is acknowledged that FEI has carried out internal audit in the past using third party auditors for Mt. Hayes facility. FEI is however required to ensure that the audit process documented in the draft report is implemented to review the performance of its IMPF and monitor achievement and progress towards the program objectives set by FEI in reference to the performance indicators, on an ongoing basis. FEI must track the implementation of the internal audit program through a Corrective Action Plan (CAP).

IMPF Components (as per Compliance Assurance Protocol)	Comments
15.0 Management Review	*Requirement/Expectation: The Management Review component requires that a permit holder review its IMPF to determine the extent to which the performance goals and objectives have been met to assess program effectiveness.* FEI has outlined the management review process for LNG assets. FEI is required to implement management review process and maintain records to demonstrate compliance to this requirement. FEI must address the implementation of management review process through a Corrective Action Plan (CAP).

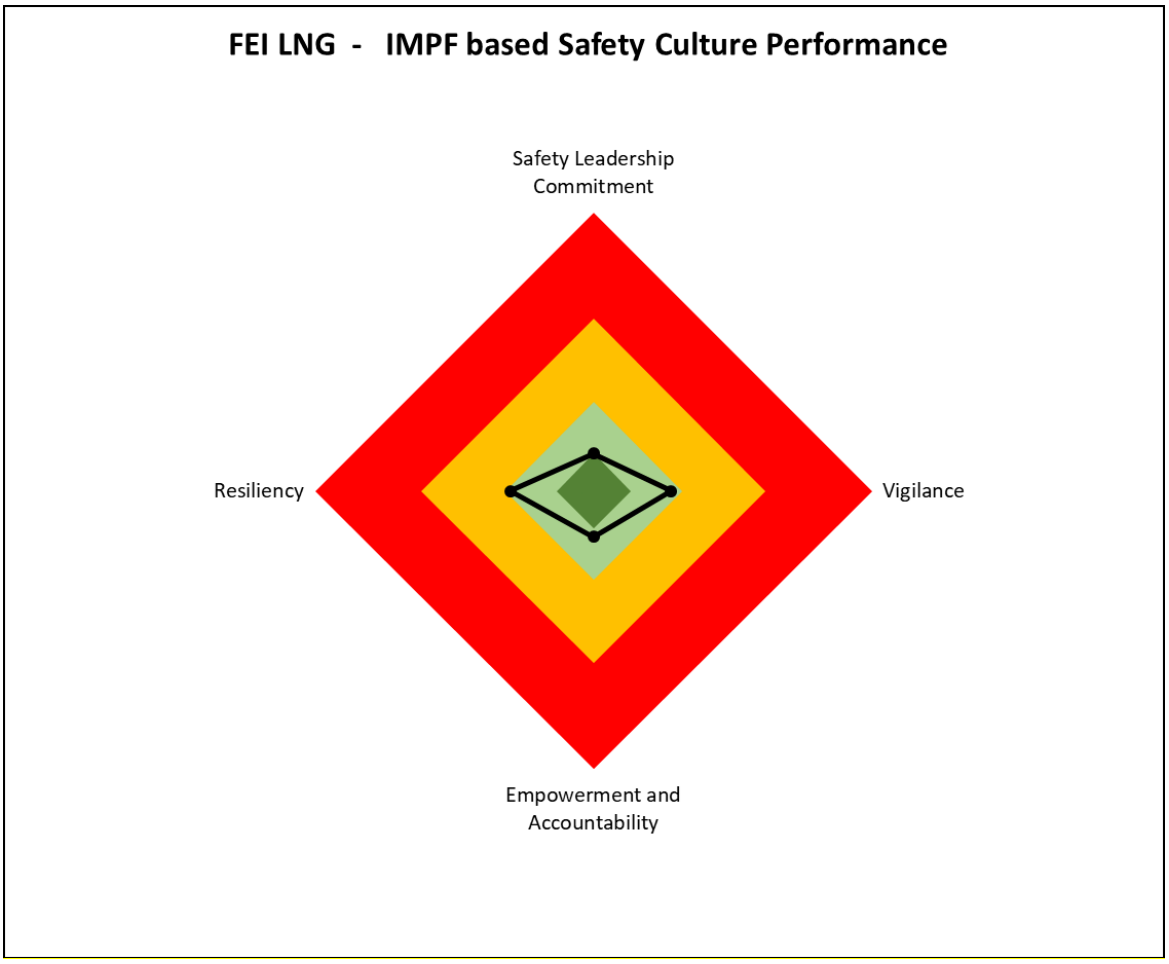
3. Audit Performance Evaluation

FEI's audit findings are analyzed and reported as compliance rate and risk priority number (RPN), which is product of non-compliance occurrence, severity of non-compliance and proposed actions. FEI compliance rate for the IMPF audit was around 78% and FEI's IMPF component based performance is graphically represented below:



3.1 Safety Culture

During the audit, the Commission reviewed and analyzed the attributes of safety culture for FEI from an IMPF perspective. Based on this review, it was found that FEI has identified safety as a core value of its Integrity management programs, its leadership and management showed commitment to safety by Executive leaders taking ownership of integrity management programs, leadership visibility in safety meetings and incident investigation and corrective actions, investing in employee training and competency assessment, and employee ownership. Graphical presentation of FEI safety culture performance is presented below.



Refer to IMPF protocol and NARWGSC Safety indicators research paper

FEI demonstrated moderately positive attitude to meeting the minimum standard requirements and incorporating process safety. FEI's leadership is required to promote reporting and learning culture by assuring information is timely gathered and shared from events. FEI must improve its resilience to respond effectively to changing demands and modifications, and to manage potential and emerging risk through better control on IMM activities, and improving record management. FEI must continue to plan and conduct formalized audits in all functional areas for continuous improvement. FEI must focus more effort on promoting safety vigilance by implementing systematic consideration and understanding of risk and performance evaluation process.

4. Corrective Action Submission and Review Process

FEI must address non-compliance findings through the development and implementation of a Corrective Action Plan (CAP). A CAP document must outline specific actions required for developing and implementing any changes needed to programs, processes, procedures, or instructions along with responsibilities, and timelines for implementation to address each finding along with any records associated with any finding. The CAP must be submitted to the Commission within 30 days of receipt of the final report.

The Commission monitors and assesses corrective actions until they have been fully resolved, which may include arranging further compliance verification assessments to ensure that corrective actions defined within CAP have been proactively implemented. Once the Commission approves a permit holder's CAP, the permit holder must continue to submit updated CAPs with corrective actions on a quarterly basis.

The Commission would like to thank FEI for their continued participation and cooperation in the Commission's compliance assurance process.

Attachment 30.24

E Source

Customers' Contact Channel Preferences

Results from the 2018 E Source Residential Utility Customer Survey

By Abbas Madad

May 23, 2019

In this report, we look at the results of the 2018 E Source Residential Utility Customer Survey to understand customers' contact channel preferences for a variety of utility interactions. We found that:

- Customers most commonly prefer interacting with their utility through the utility website, phone via live agent, and email.
- Customers prefer to receive notifications through text messages or email.
- When it comes to emerging channels, most customers would prefer automated chatbot via text to ask general customer service questions or to learn about energy usage.
- Most customers call their utility to contact customer services or to complete an interaction.
- Customers don't think that reporting an electric outage; checking the outage status; or starting, stopping, or transferring service are seamless experiences.

Customers most commonly prefer interacting with their utility through the utility website, phone via live agent, and email.

How do customers prefer to interact with their utility?

Overall, customers prefer to interact with their utility through the utility website, phone via live agent, or email (**figure 1**). The least popular channels among respondents for any utility interaction were smart speakers/voice-controlled devices, live web chat, and in-person at a walk-in center.

Figure 1: Preferred contact channels for utility-customer interactions

Respondents favored the utility website for 6 of the 11 interactions we asked about. For the other 5 interactions, respondents favored phone via live agent. Overall, email was the third most preferred contact channel.

	Percentage of respondents								
Viewing my energy bill details	53	22	14	14	8	7	7	4	3
Paying my utility bill	52	11	15	15	6	10	13	3	3
Enrolling in utility programs and services	44	17	35	10	7	8	10	6	3
Receiving information about energy-efficient usage	41	35	16	11	9	7	7	5	3
Receiving information on utility programs and services	41	38	19	10	10	7	8	5	3
Checking the status of power outages	40	15	30	16	18	18	5	5	3
General inquiries about my utility services	38	19	46	11	8	10	9	7	3
Switching rates or billing plans	36	15	41	9	8	8	10	5	3
Scheduling or checking the status of a service appointment	35	18	42	13	13	11	7	5	3

Base: All respondents (n = 2,001). **Question S1_5:** What are your preferred contact methods or channels for each of the following interactions with your utility? Select all that apply. **Note:** IVR = interactive voice response.

	Percentage of respondents								
Transferring connection, establishing new service, or stopping service	32	12	50	10	7	9	12	5	3
Reporting power outages	28	13	46	14	16	20	6	5	4

Base: All respondents (n = 2,001). **Question S1_5:** What are your preferred contact methods or channels for each of the following interactions with your utility? Select all that apply. **Note:** IVR = interactive voice response.

Through what contact channels do utility customers prefer to receive notifications?

For all notifications, customers prefer to receive them via text or email (**figure 2**). When it comes to power outage notifications, customers also like to receive a phone call with an automated voice message. Some customers prefer mobile app notifications, but when it comes to social media or smart speaker notifications, few customers are interested.

Figure 2: Customers' preferred contact channels for receiving utility notifications

Respondents are more interested in receiving billing and payment notifications via email, but for power outage or weather-related notifications, they're more interested in text messages.

	Percentage of respondents					
Payment posted	57	26	14	13	5	5
Billing statement ready	57	25	14	13	6	5
Bill payment due date approaching	53	30	14	15	5	5
Bill payment late	45	34	15	23	6	5

Base: All respondents (n = 2,001). **Question S1_10:** What would be your preferred channel for each of the following utility alerts and notifications? Select all that apply.

	Percentage of respondents					
Service appointment reminder	40	42	13	29	7	6
Scheduled power outage due to maintenance	40	42	14	33	7	6
Status update on a power outage in your area	31	46	15	32	7	5
Severe weather alert	30	46	16	28	7	6
Power outage detected or reported in your area	30	45	15	35	7	6

Base: All respondents (n = 2,001). **Question S1_10:** What would be your preferred channel for each of the following utility alerts and notifications? Select all that apply.

What emerging channels are customers interested in?

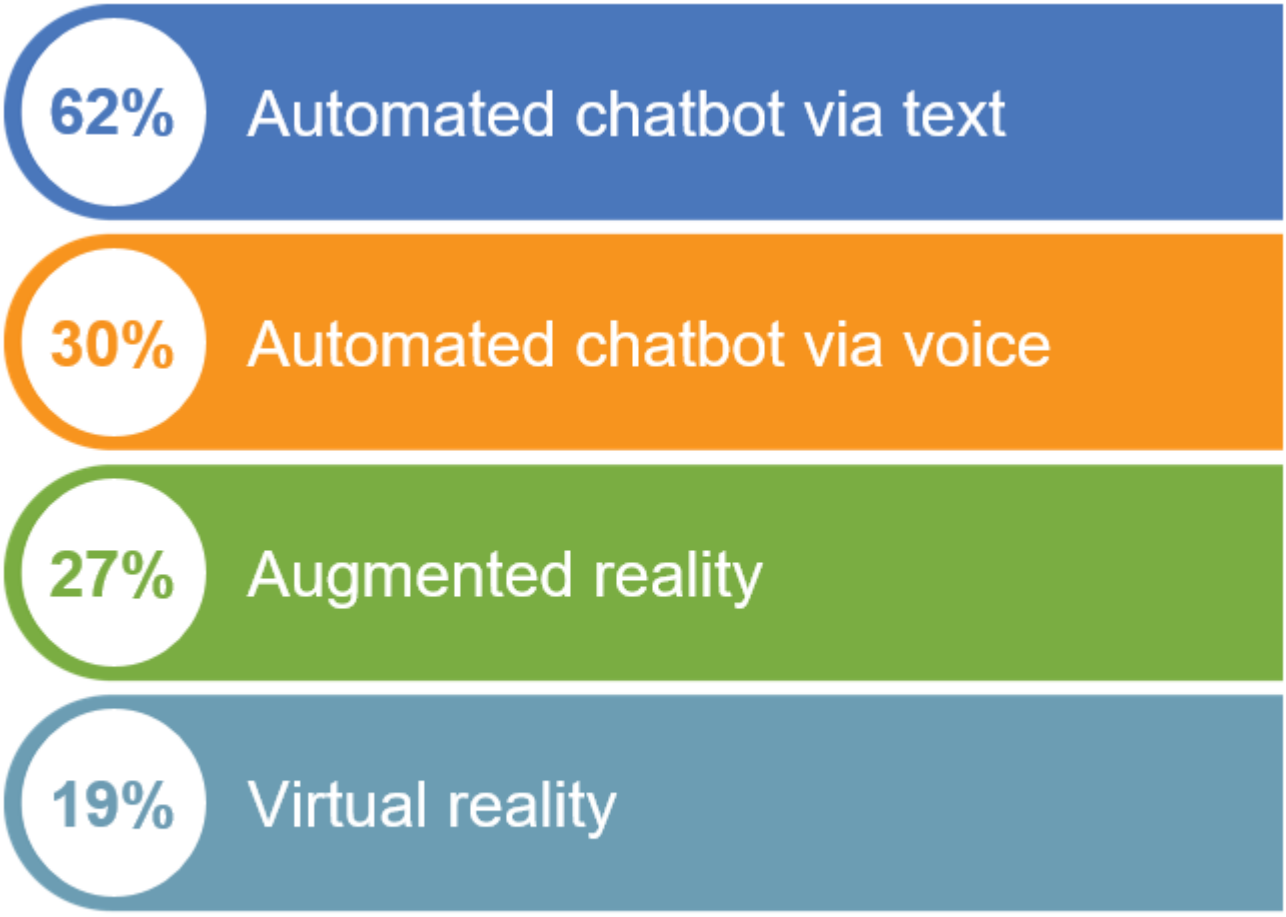
When asked which emerging contact channels they would prefer to use to interact with their utility, the majority of customers chose automated chatbots (**figure 3**). The four channels we asked them about were:

- Automated chatbot via text (such as a chat window on a website or a messaging platform like Facebook Messenger)
- Automated chatbot via voice (such as a voice-operated speaker like Google Home or Amazon Echo)
- Augmented reality (digital information overlaid on a real environment)
- Virtual reality (an immersive artificial digital environment)

Figure 3: Customers' interest in emerging contact channels

Utilities could take their interactions with their customers to the next level by investing in automated chatbots as a contact channel. This can improve customer communications because these chatbots

respond as a live agent would, and they respond quickly. Not to mention, automated chatbots are more cost-effective in the long run.



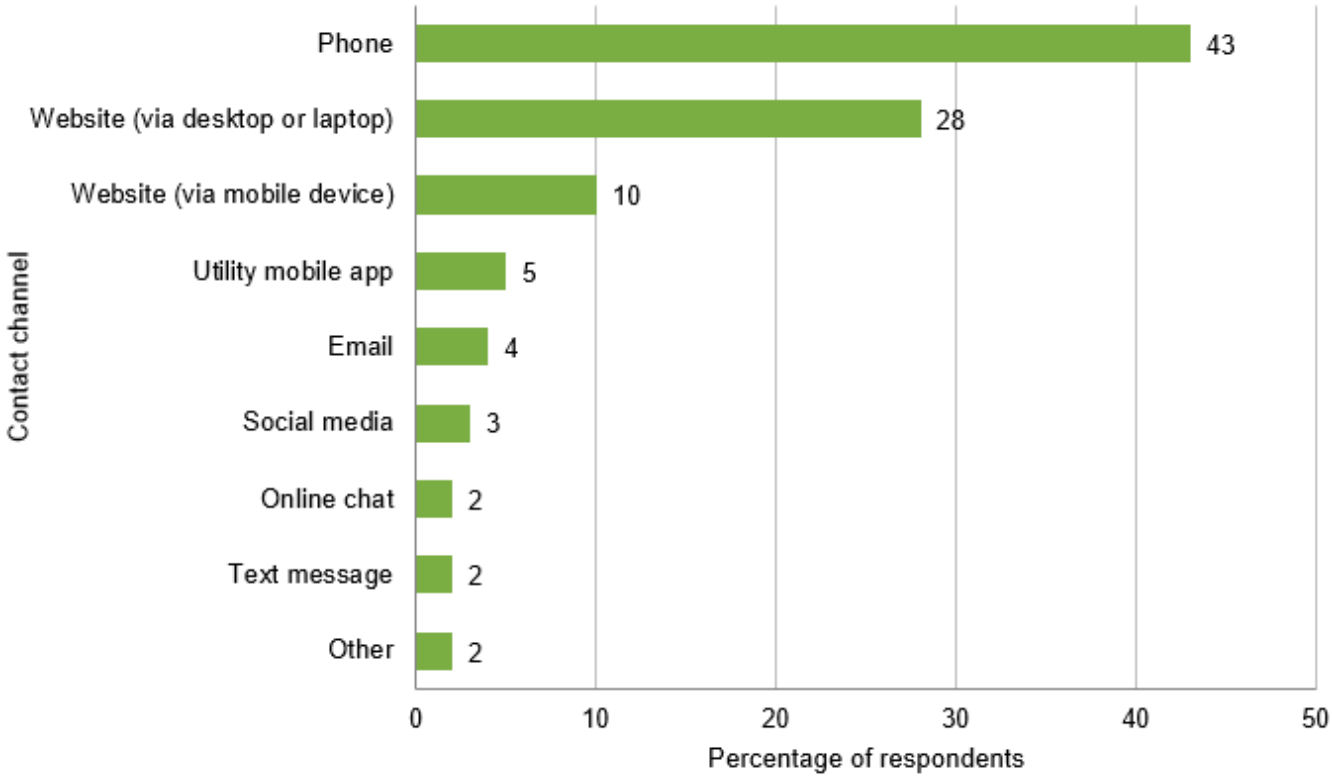
Base: All respondents (n = 2,001). **Question S1_6:** If your utility made it possible, which of the following would you be interested in using to perform activities such as asking a general customer service question or learning about energy-efficient usage? Select all that apply.

What channels do customers first use to contact their utility?

On their first interaction with their utility, 43% of customers use the phone when they need customer services or when they're completing an interaction such as paying a bill or reporting an outage (**figure 4**). Twenty-eight percent of customers first go through the website via desktop/laptop, and 10% first go through the website via mobile device.

Figure 4: Customers' first-choice channels

Most customers first call their utility, with the expectation that the customer service rep (CSR) will be able to complete their task quickly and in real time. To drive traffic from the CSRs to the website, you need to have a user-friendly and detailed website that makes it easy for customers to self-serve.



Base: All respondents (n = 2,001). **Question S1_8:** Where do you typically go first for customer service or for completing an interaction with your utility such as paying a bill or reporting an outage?

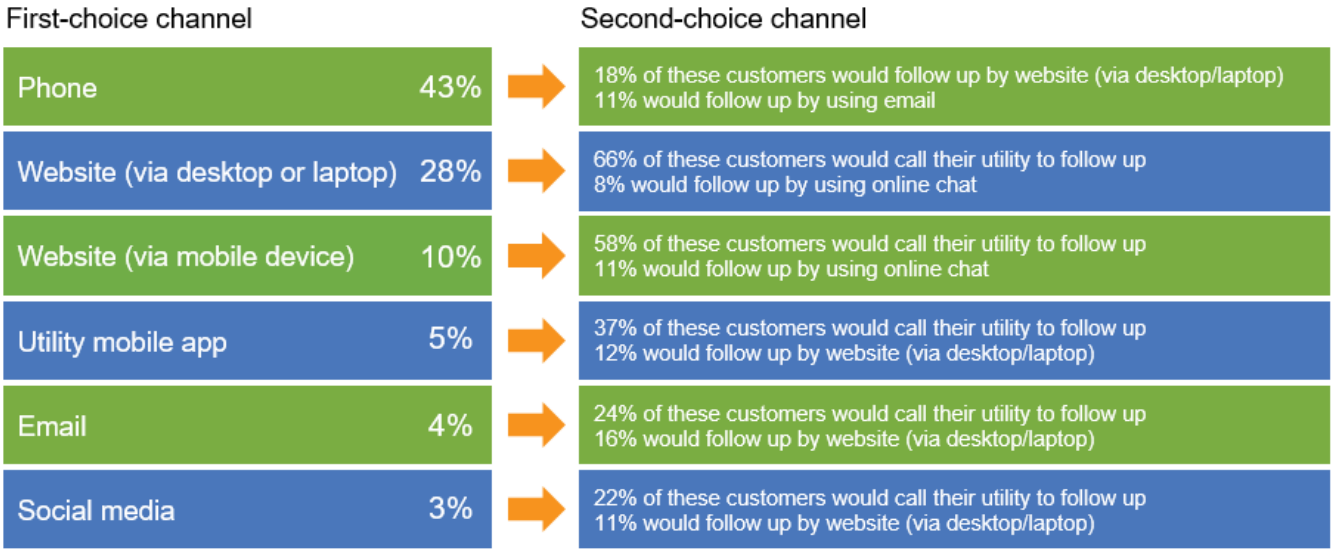
Where do customers turn when their issue isn't resolved via their first-choice channel?

When customers who initially contact their utility via the company's mobile app don't get the resolution they need, they next contact their utility via phone to solve their problem. We can see in **figure 5** that customers turn to the website via desktop/laptop (18%) or email (11%) after they've unsuccessfully contacted their utility by the phone.

Figure 5: Customers' second-choice channels

Customers whose first-choice channels are digital mostly turn to the phone as their backup channel.

Those who first use the website also consider online chat, and those who first use a mobile app, email, or social media also consider website via desktop/laptop.



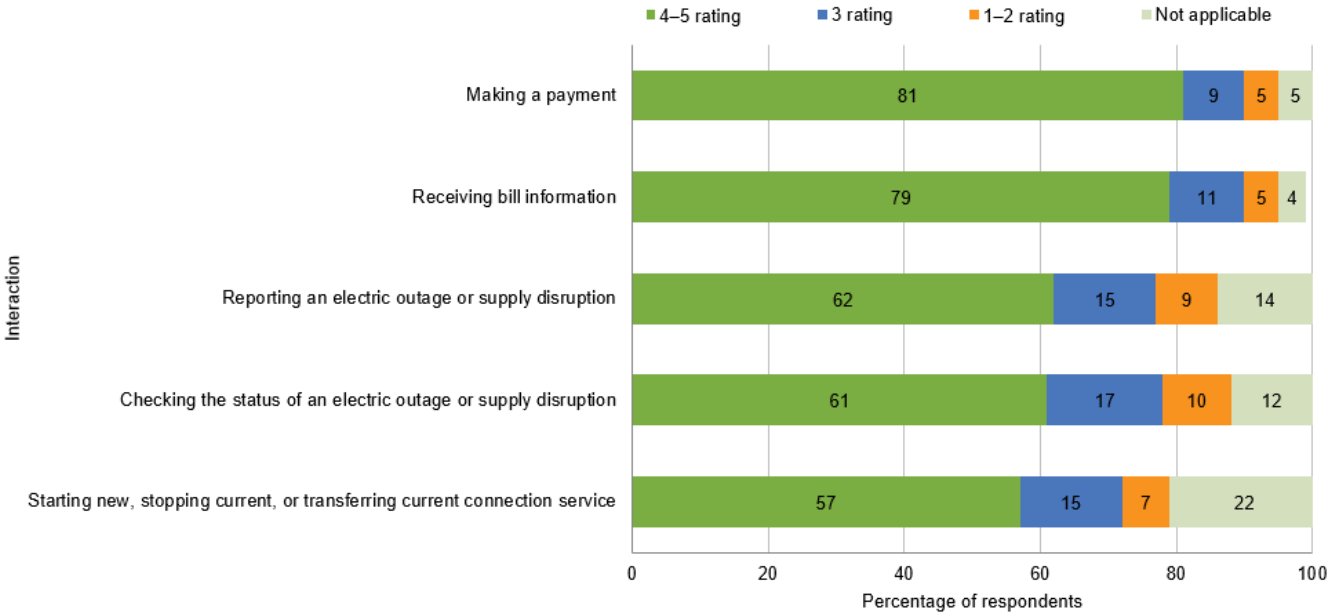
Base: All respondents (n = 2,001). **Question S1_8:** Where do you typically go first for customer service or for completing an interaction with your utility such as paying a bill or reporting an outage? **S1_9:** If your first contact with your utility didn't successfully resolve your issue or complete your task, which channel would you use to contact your utility next?

How seamless of an experience do customers have?

We asked customers to rate the seamlessness of their experience—on a scale of 1 to 5, where 1 means not at all seamless and 5 means extremely seamless—when interacting with their utility across a variety of channels and for a variety of interactions (**figure 6**). When making a payment or receiving bill information, four out of five customers had a seamless experience. However, for reporting an electric outage; checking outage status; and starting, stopping, or transferring service, only three out of five customers rated their experience as seamless.

Figure 6: Seamlessness of the customer experience

For many customers, reporting and checking the status of an outage and making changes to their service aren't seamless experiences.



Base: All respondents (n = 2,001). **Question S1_7A_1:** On a scale of 1 to 5, where 1 means not at all seamless and 5 means extremely seamless—seamless meaning consistent across communication methods and updated in real time—how seamless of an experience have you had with your utility when interacting with them across a variety of channels (such as phone, website, or email)?
Note: Percentages may not add to 100 due to rounding.

Attachment 32.8

A. EVALUATION OF THE PERFORMANCE BASED RATEMAKING (PBR) PLAN

1.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.1, Table 1-2, pp. 4-6

Overview of operating and maintenance (O&M) savings

On page 4 of the Application, FortisBC Energy Inc. (FEI) states the following:

> Table 1-2 below shows the formula O&M savings for each year of the PBR Plan and the cumulative to date. The table also shows the embedded Productivity Improvement Factor (PIF) savings for the same years. The table shows that in addition to the cumulative formula O&M savings of approximately $37.4 million to the end of 2017 which are shared with customers, the cumulative PIF savings to the benefit of customers total approximately $10.0 million.

On page 5 of the Application, FEI states: "Major initiatives involving processes that may span across departments are described in Section 1.4.3 below and comprise a significant portion of the productivity savings, accounting for approximately $5.0 million of the accumulated O&M savings."

[redacted]

[1] Appendix C2 Report on Initiatives during the PBR Term.

1.7 Of all the defects repaired, what percentage of the repairs were results of the new CSA Z662 defect criterion?

Response:

FEI clarifies that the strain based criteria for dents, which are discussed below, have been applied by FEI since 2013.

Dents reported through in-line inspection or as found during integrity digs and other activities are generally considered acceptable by FEI unless they meet the strain-based criteria for dents listed in CSA Z662-15 Clause 10.10.4.2 a) through f), or the following additional criteria developed by FEI based on the factors listed in the response to BCUC IR 1.1.5:

- Estimated curvature strain greater than or equal to 4 percent for dents interacting with a mill or field weld; or
- Estimated curvature strain greater than or equal to 6 percent for dents on the pipe body; or
- Depth exceeding 6 mm in pipe 323.9 mm outside diameter (OD) or smaller for dents interacting with a mill or field weld, regardless of the estimated curvature strain; or
- Depth exceeding 2 percent of the OD in pipe larger than 323.9 mm OD for dents interacting with a mill or field weld, regardless of the estimated curvature strain; or
- Depth exceeding 6 mm in pipe 101.6 mm OD or smaller for dents on the pipe body, regardless of the estimated curvature strain; or
- Depth exceeding 6 percent of the OD in pipe larger than 101.6 mm OD for dents on the pipe body, regardless of the estimated curvature strain.

FEI does not track the percentage of repairs explicitly based on the strain-based dent criteria, as integrity dig selection is based on engineering consideration of multiple factors of which dent strain may be a component.

A 2010-2016 history and a 2017-2018 forecast of integrity dig numbers is provided below to illustrate increases to integrity dig numbers, along with reasons for the digs.

Reason for Digs	Number of Digs per Year								
	2010	2011	2012	2013	2014	2015	2016	2017 YEF	2018 Forecast

Reason for Digs	Number of Digs per Year								
	2010	2011	2012	2013	2014	2015	2016	2017 YEF	2018 Forecast
Dent digs (includes dig selections that were influenced by the strain-based criteria)	3	0	6	27	12	10	32	15	under development (u/d)
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	0	27	20	11	45	u/d
Other ILI digs	32	45	24	21	19	32	33	28	u/d
Non-ILI digs	13	9	8	4	4	2	0	9	u/d
Total Integrity Digs	**48**	**54**	**36**	**52**	**62**	**64**	**76**	**97**	**≈ 110 +/- 10%**

1

2 The 2010-2016 history of structural repairs at integrity dig sites is provided in the following table.

Reason for Structural Repairs	Number of Structural Repairs per Year						
	2010	2011	2012	2013	2014	2015	2016
Dent repairs due to CSA Z662 criteria	0	1	1	0	1	1	1
Dent repairs due to FEI determination	0	0	3	2	3	1	12
Metal loss repairs due to CSA Z662 criteria	3	4	0	1	2	2	1
Metal loss repairs due to FEI determination	2	0	2	0	2	3	2
Other repairs (e.g. weld-related issues, material testing cut-outs)	1	5	1	2	2	2	0
Total Structural Repairs	**6**	**10**	**7**	**5**	**10**	**9**	**16**

3

4 The percent of repairs associated with dents are as follows. Included in these numbers are the
5 dent repairs resulting from the strain-based dent criteria.

	2010	2011	2012	2013	2014	2015	2016

% of Repairs Associated with Dents (includes repairs resulting from the strain-based criteria)	**0%**	**10%**	**57%**	**40%**	**30%**	**20%**	**81%**

FEI notes that fluctuations in repair rates will vary year-to-year based on factors such as in-line inspection tool reporting bias, the adoption of new repair criteria, and other possible factors.

[redacted]

Attachment 42.4

REFER TO LIVE SPREADSHEET MODELS

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Attachment 46.2

Project Name:	5 Year Turnaround at Tilbury LNG Expansion		
Construction Start Year	2023	In-Service Year	2023
Expected Capital Cost	$2,485k	Project Definition	AACE Class 5

Need:

Regulated pressure vessels at the Expanded Tilbury LNG Facility need to be inspected internally as per 5-year inspection program required by operating permit.

Alternatives:

1) Perform internal inspection of all regulated pressure vessels.

Project Description:

Alternative 1 is the preferred option. The regulated pressure vessels at the Expanded Tilbury LNG Facility will undergo internal inspection as per the 5-year program to meet permit requirements.

Benefits:

Internal inspection of regulated pressure vessels will meet operating permit requirements.

Scope:

Internally inspect all regulated pressure vessels at Expanded Tilbury LNG Facility. The inspection will require taking the plant offline, isolating and cleaning each vessel, performing the required internal inspection, and recommissioning the plant.

Consultation:

No consultation is required.

Public Interest Issues:

None.

Risks:

No significant risks.

Project Name:	240 St. & 102 Ave. Station, Maple Ridge – Insufficient Capacity		
Construction Start Year	2021	In-Service Year	2021
Expected Capital Cost	$2,500k	Project Definition	AACE Class 4

Need:

Due to growth in the eastern section of Maple Ridge, the supply provided by the existing district station infrastructure is insufficient.

Alternatives:

1) Replace the station with higher capacity equipment that can supply the required flow to the distribution system. Station will need to be relocated approximately 1km away, and the following pipe will need to be installed: approx. 1,000m x 168mm IPST, 1,000mx168mm DPPE.

2) Increase the station's effective capacity by increasing the inlet pressure of the station through looping the intermediate pressure pipeline feeding the station. Approx. 4,000m x 168mm IPST would be required.

3) Increase the stations effective capacity by increasing the inlet pressure of the station through increasing the MOP of the intermediate pressure pipeline that feeds the station. Existing pipe is unable to handle the higher MOP and ~10,000m of new 168mm pipeline would be required.

Project Description:

Due to long-term considerations on the capacity of the existing pipeline, Alternative 3 is the preferred option, although additional development of options 1 and 3 are ongoing. If option 3 is selected, the project will include alterations to the McKay Ave and River Rd Station in Maple Ridge, the installation of approximately 10,000m of 168mm intermediate pressure pipeline, and the deration of the existing IP pipeline to distribution pressure.

Benefits:

Installation of the new higher pressure pipeline will allow the existing stations to serve the area for the forecast period and support future expected growth in Maple Ridge. Continued use of the existing pipeline as a DP main will provide resilience to the existing distribution system.

Scope:

Install 10,000m x 168mm IP pipeline from McKay Rd and River Rd to 272 St and 100 Ave, Maple Ridge.

Consultation:

Consultation will be required with the City of Maple Ridge and the Oil and Gas Commission when the replacement pipeline permit is applied for under the Oil and Gas Activities Act.

Public Interest Issues:

None.

Risks:

Option 1 has risks associated with finding a suitable location within the acceptable footprint.

Project Name:	Grand Forks to Trail 273 Pipeline Alteration		
Construction Start Year	2020	In-Service Year	2020
Expected Capital Cost	$3,589k	Project Definition	AACE Class 4

Need:

Population growth around the Grand Forks to Trail 273 transmission pipeline has caused approximately 2.7 km of pipeline to increase in class location, requiring a reduction of the stress in the pipe to meet code requirements.

Alternatives:

1) Replace 2.7 km of pipeline with new pipeline designed to meet class location requirements.

2) Install a pressure control station and lower the maximum operating pressure of the pipeline to meet class location requirements.

Project Description:

Alternative 1 is the preferred option. Lowering the operating pressure of the Grand Forks to Trail 273 transmission pipeline would result in loss of capacity. Approximately 2.7 km of transmission pipeline will be replaced to meet the current operating pressure for a Class 3 location and allow for future growth in the area.

Benefits:

Replacement of 2.7 km of pipeline will address the class location change to meet code requirements, while maintaining the pipeline's capacity to serve customers.

Scope:

Install approximately 2.7 km of the Grand Forks to Trail 273 pipeline in Grand Forks, including a 150 m HDD across the Kettle River.

Consultation:

Directly impacted landowners and the local municipality will be notified of the work.

Public Interest Issues:

None.

Risks:

No significant risks. Routine work.

Project Name:	Huntingdon to Nichol In Line Inspection		
Construction Start Year	2023	In-Service Year	2023
Expected Capital Cost	$2,760k	Project Definition	AACE Class 3

Need:

In-line inspection of the Huntingdon to Nichol 762 transmission pipeline is required as per the 7-year inspection program for this pipeline.

Alternatives:

1) Perform in-line inspection of the Huntingdon to Nichol 762 transmission pipeline.

Project Description:

Alternative 1 is the preferred option. The Huntingdon to Nichol 762 transmission pipeline will be inspected as per the 7-year inspection program required by FEI's Pipeline Integrity Management Program.

Benefits:

In-line inspection of this pipeline will meet integrity management program requirements by allowing the assessment of time-dependent threats and features that could impact the integrity of this pipeline.

Scope:

Perform internal inspection of the Huntingdon to Nichol 762 transmission pipeline using Magnetic Flux Leakage (MFL), Circumferential Magnetic Flux Leakage (CMFL) and Geometry tools.

Consultation:

No consultation is required.

Public Interest Issues:

None.

Risks:

No significant risks. Routine work.

Project Name:	NW Kamloops Secondary Supply - Install Loop from Westsyde to Rayleigh		
Construction Start Year	2023	In-Service Year	2023
Expected Capital Cost	$3,900k	Project Definition	AACE Class 4

Need:

There is currently only a single supply of natural gas to the distribution system feeding the north west part of Kamloops and the surrounding area on the west side of the North Thompson River. If normal operation of the primary feed is interrupted, there is no redundancy to the system.

Alternatives:

1) Install an IP pipeline across the North Thompson River from Rayleigh to Westsyde Rd, ending with a new district station on the west side of the river.

2) Do nothing and accept the risk of service interruption.

Project Description:

Alternative 1 is the preferred option. FEI will be installing a second supply point into the north-west part of Kamloops. This will consist of a new Intermediate Pressure pipeline starting in Rayleigh and crossing the North Thompson River, ending at a new district station on Westsyde Rd to feed the distribution system.

Benefits:

Installation of the pipeline will increase the reliability of service to the customers in and around the north-west part of Kamloops.

Scope:

Install a new Intermediate Pressure pipeline between the Westsyde of Kamloops and Rayleigh, including a directionally drilled crossing of the North Thompson River.

Consultation:

Consultation will be required with the City of Kamloops for installations that occur on their property. Consultation with local First Nations will be required for work that affects their lands through the OGC application process for a new permit under the Oil and Gas Activities Act.

Public Interest Issues:

None.

Risks:

Unsuccessful trenchless crossing of the North Thompson River could result in higher than expected costs, as a second attempt would be required.

Project Name:	Penticton Second Supply		
Construction Start Year	2020	In-Service Year	2020
Expected Capital Cost	$2,100k	Project Definition	AACE Class 4

Need:

There is currently only a single supply of natural gas to the distribution system feeding Penticton and the surrounding area. If normal operation of Penticton Gate Station is interrupted, there is no redundancy to the system.

Alternatives:

1) Install a second gate station on the transmission line in the area to feed the distribution system

2) Do nothing and accept the risk of service interruption.

Project Description:

Alternative 1 is the preferred option. FEI will be installing a second major supply point into the City of Penticton. This will consist of a new gate station attached to the transmission system and 4km of 219mm DPPE main to connect the station to the existing distribution system.

Benefits:

Installation of the pipeline will increase the reliability of service to the customers in and around the City of Penticton.

Scope:

Install a second supply for the City of Penticton, consisting of a gate station connected to the transmission system and 4km 219mm DPPE connecting main with additional valves for isolation.

Consultation:

Consultation will be required with the City of Penticton for routing the new 219mm DPPE main. Consultation with local First Nations will be required in and around the location of the new gate station through the OGC application process for a new permit under the Oil and Gas Activities Act.

Public Interest Issues:

None.

Risks:

Appropriate land needs to be found and purchased for the placement of the gate station.

Project Name:	SI – 1300m x 323 IPST Riverside, Abbotsford		
Construction Start Year	2024	In-Service Year	2024
Expected Capital Cost	$3,587k	Project Definition	AACE Class 4

Need:

Low pressures at the tail end of the Intermediate Pressure pipeline that feeds customers in Mission are expected due to growth.

Alternatives:

1) Replace the existing 168mm IPST pipeline with one of a larger diameter.

2) Loop 1300m of the existing 168mm IPST pipeline with 323mm IPST along Riverside Rd.

Project Description:

Alternative 2 is the preferred option. Due to the increased demand in Mission, install 1300m x 323 IPST along Riverside Rd from Hallert Rd to Grace Rd in Abbotsford.

Benefits:

Installation of the pipeline will allow FEI to continue to provide reliable and uninterrupted service to customers in the Mission area.

Scope:

Install 1300m x 323 IPST along Riverside Rd from Hallert Rd to Grace Rd in Abbotsford.

Consultation:

Consultation will be required with the City of Abbotsford and the public in and around the new pipeline through the OGC application process for a new permit under the Oil and Gas Activities Act.

Public Interest Issues:

None.

Risks:

No significant risks. Routine work.

Project Name:	SI – 1850m x 168 IPST McLeod, Chilliwack		
Construction Start Year	2022	In-Service Year	2022
Expected Capital Cost	$2,404k	Project Definition	AACE Class 4

Need:

Low pressures at the tail end of the distribution system in Chilliwack are expected due to growth.

Alternatives:

1) Install 1850m x 168mm DPPE pipe to boost the pressures in the tail end of the system.
2) Install 1850m x 168mm IPST pipe and a new IPDP District Station to boost the pressures in the tail end of the system.
3) Install 1850m x 168mm DPST pipe rated for IP use, run the extension at distribution pressure until the pressures drop and the pipe needs to be uprated to IP and a new IPDP District Station is built.

Project Description:

Alternative 3 is the preferred option. Due to the demand expected for the area, install 1850m x 168 IPST along McLeod Rd. The pipeline will be operated at Distribution Pressure for a number of years, and, when pressures dictate, uprated to run at IP with a new IPDP district station at the intersection of Chilliwack Central Rd and Upper Prairie Rd.

Benefits:

Installation of the pipeline will allow FEI to continue to provide reliable and uninterrupted service to customers in the Chilliwack area.

Scope:

Install 168mm steel DP/IP pipe from Yale Rd to Chilliwack Central Rd along McLeod, Operate at 420kPa until system pressures necessitate a pressure increase.

Consultation:

Consultation will be required with the City of Chilliwack and the public in and around the new pipeline when the pressure is raised to IP and a new OGC permit is applied for under the Oil and Gas Activities Act.

Public Interest Issues:

None.

Risks:

No significant risks. Routine work.

Project Name:	Tilbury LNG Air Cooler Upgrade		
Construction Start Year	2023	In-Service Year	2023
Expected Capital Cost	$3,184k	Project Definition	AACE Class 5

Need:

The boil-off gas cooler at the Tilbury LNG facility is near the end of its life expectancy and showing signs of corrosion. The cooler is required to maintain plant service as failure of this unit will result in loss of operation of the boil off gas compressor.

Alternatives:

1) Replace air cooler unit to maintain service.
2) Refurbish air cooler unit to maintain service.
3) Do nothing, run cooler until failure.

Project Description:

Currently, an engineering assessment is being performed on the cooler to determine the refurbishment or replacement options.

Benefits:

Refurbishment or replacement of the boil-off gas cooler will allow for continued service and prevent venting of natural gas.

Scope:

Install new or refurbish existing boil-off gas cooler at the Tilbury LNG facility. Final scope to be determined during project development.

Consultation:

No consultation required.

Public Interest Issues:

None.

Risks:

No significant risks.

Project Name:	V1 Compressor Unit 1, 2 & 3 Engine Overhaul and Emissions Reduction to 15 PPM		
Construction Start Year	2022-2024	In-Service Year	2022-2024
Expected Capital Cost	$7,889k	Project Definition	AACE Class 4

Need:

Compressor unit overhauls are required to ensure reliable operation of each unit. Additionally, a reduction in the NO_x emissions from each compressor unit engine is required to comply with the Metro Vancouver emissions permit.

Alternatives:

1) Overhaul compressor units and upgrade the engines to reduce NO_x emissions.

Project Description:

Alternative 1 is the preferred option. V1 Compressor Station Units 1, 2 & 3 will be overhauled and their engines upgraded to reduce NO_x emissions from 25 parts per million (PPM) to 15 PPM.

Benefits:

The overhaul of each unit will be performed to meet original equipment manufacturer (OEM) recommendation for reliable operation of each unit. Upgrade to the engines to reduce NO_x emissions will ensure compliance with the Metro Vancouver emissions permit.

Scope:

Overhaul Unit 1, 2 & 3 compressor units as per OEM recommendation and upgrade engine to reduce NO_x emissions from 25 PPM to 15 PPM. Unit 1 will be completed in 2022, Unit 2 will be completed in 2023 and Unit 3 will be completed in 2024.

Consultation:

No consultation is required.

Public Interest Issues:

None.

Risks:

No significant risks.

Attachment 60.3

PROJECT NAME: KELOWNA BULK TRANSFORMER ADDITION

Need:

The Kelowna Bulk Transformer Addition is a load-driven project. 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, as required by FBC's transmission planning criteria. The project is also required to ensure continued compliance with BC Mandatory Reliability Standard TPL-001-4, which requires that applicable thermal ratings are not exceeded following the loss of a single element.

Alternatives:

Four technically feasible alternatives were identified:

1. 230kV/138kV transformer addition at F.A. Lee terminal with ring bus configuration (recommended option)
2. 230kV/138kV transformer addition at F.A. Lee terminal with split bus configuration
3. 230kV/138kV transformer addition at D.G. Bell terminal
4. 230kV/138kV transformer addition at Duck Lake terminal

Benefits:

This project is required to ensure continued compliance with FBC transmission planning criteria and BC MRS.

Scope:

Regardless of alternative selected, the high-level scope will be to add a new 120/160/200 MVA, 230/138 kV transformer to the Kelowna area and complete all substation and transmission line modifications required to accommodate the new transformer.

Capital cost and accuracy level:

Approximately $20 million. A Class 3 estimate will be included in the CPCN Application.

Construction start date:

2020

In-service date:

2022

Consultation:

Public consultation and consultation with key government and community stakeholders was undertaken for this project in 2012. Another Open House will be held in 2019/20 and letters will be mailed to residents within 500 meters of the substation notifying them of the project.

All work on the proposed project is being completed within the existing property and fence boundaries of the FA Lee Terminal with no need to acquire additional property or right-of-way. There are no First Nations communities or reserves in the direct vicinity of the FA Lee Terminal. Therefore, FortisBC did not consult with First Nations on this project in 2012.

Public interest issues:

Substation work will be completed inside the existing Terminal fence. Minor modifications to existing transmission and distribution lines will be in the area directly adjacent to the Terminal. As such, there will be very limited public impact.

Risks:

A detailed risk register for this project is currently under development. In terms of risks associated with the project not being in-service by 2022, there is a risk that FBC would not comply with Mandatory Reliability Standards due to forecast load growth in the Kelowna area.

Description of the project:

The project consists of the installation of a new 120/160/200 MVA, 230/138 kV transformer at the FA Lee Terminal, which would operate in parallel with the two existing 230/138 kV transformers at FA Lee Terminal and in tandem with the existing 230/138 kV transformer at DG Bell Terminal. The project also includes necessary modifications to the FA Lee Terminal and interconnected transmission and distribution lines to accommodate the additional transformer.

Attachment 72.4

Energy at work FORTIS BC™

Jeremy Hewitt
Assistant Deputy Minister, Climate Action Secretariat
Government of British Columbia
VIA EMAIL Jeremy.Hewitt@gov.bc.ca

Re: FortisBC comments on the Clean Growth Incentive Program

April 1, 2019

Dear Mr. Hewitt,

FortisBC delivers approximately 21 per cent of the energy consumed in British Columbia, the most by any entity in the province. We own and operate two liquefied natural gas (LNG) storage facilities and operate seven hydroelectric generating plants, four of which we own. Our more than 2,200 employees serve approximately 1.1 million customers in 135 communities across B.C. We are investing a further $2.8 billion in capital expenditures between 2017 and 2021. We are committed to investing in projects that will make life more affordable for British Columbians, improve efficiency, reduce greenhouse gas emissions and drive innovation.

Last summer, FortisBC developed its Clean Growth Pathway, which was our response to the Intentions Papers published to inform the provincial climate strategy. In the Pathway, we outlined four main areas of action that FortisBC would undertake to help achieve the Province's 2030 and 2050 greenhouse gas (GHG) emission reduction goals: i) expanding our natural gas in transportation offerings, ii) a renewable gas target for 2030 and 2050, iii) emission savings investments in building energy efficiency and technology, and iv) international GHG emissions reductions through LNG marine fueling and export. We recognize the consideration that the Climate Action Secretariat (CAS) made on behalf of Clean Growth Pathway.

Our Clean Growth Pathway also made a number of recommendations regarding the Clean Growth Program for Industry. We support the approach to maintain industrial competitiveness while offering incentives to reduce GHG emissions. In this letter, I want to outline FortisBC's position on a number of different elements of the Clean Growth Incentive Program (CGIP). These comments are made based on FortisBC's long-experience in program delivery, our relationships with industrial clients and the multi-faceted nature of FortisBC as both a registered utility in the province and a business acutely sensitive to competitiveness concerns our Tilbury LNG expansion.

1. **Inclusion of FortisBC in the CGIP**

FortisBC believes that local gas distribution utilities should be included in the CGIP with a performance baseline to access the CGIP carbon tax incentive. FortisBC currently pays carbon tax on its operational combustion emissions and this cost is flowed through to ratepayers as part of FortisBC's delivery charge. While this cost is a small component of the delivery charge each consumer pays, we seek to qualify for the carbon tax incentive because we cannot differentiate between the gas delivered to consumers and gas delivered to our Tilbury LNG site. This means that if the local distribution and transmission system is not eligible to receive the carbon tax incentive that LNG from the Tilbury expansion destined for export

or for marine fueling will be negatively impacted by incremental carbon tax payments above $30 per tonne.

This would put Tilbury LNG, designed to be cleanest LNG facility in the world, on unequal footing with other LNG projects in the province and internationally. For example, Puget Sound Energy (PSE) is developing an LNG production facility that will enable LNG supply for marine and transportation markets in the region. This LNG facility will incorporate LNG liquefaction, storage and bunkering to the marine market. The project is scheduled to be completed in late 2019 and will use BC and Alberta natural gas as a fuel source. As Washington State has not instituted a carbon pricing framework, neither the facility nor the LDC will be subject to a carbon tax. Allowing FortisBC's gas distribution and transmission systems to be eligible for the carbon tax incentive would address this imbalance while having a very small overall impact and price signal to individual consumers. At the same time, the full carbon tax will still be applied to each of our consumers' gas bills maintaining the carbon price signal to use gas efficiently.

2. Determining FortisBC's performance benchmarks

Because each gas system in the world is unique - based on specific geographical, temperature, economic and population settlement characteristics - we do not believe that it is useful to conduct a direct comparison of emissions intensity between jurisdictions. Instead, we propose a framework that develops a performance benchmark based on the assets and practices of the utilities in BC. For example, we recommend developing "best in the world" benchmarks for physical assets such as distribution pipe material using polyethylene (PE). PE pipe relative to steel pipe has a lower methane emission factor. A performance benchmark for this asset type could involve the use of 100% PE pipe for FortisBC distribution system. A key consideration in developing the benchmark is taking FortisBC's context into account. For example, if 100% PE is the benchmark as achieved by a gas utility in another jurisdiction, a reasonableness test should be developed to account for the cost-differences between FortisBC and the leading jurisdiction. It may be that a geographically small and dense jurisdiction has the world leading system with much smaller total length of pipe than FortisBC. In order to put both utilities on equal foot, we recommend developing a cost-test with thresholds to determine whether it is truly feasible for a utility like FortisBC to hit the benchmark and, if not, to develop benchmarks that are effective but more appropriate.

3. Design and scope of the Clean Growth for Industry Fund

Another reason for including FortisBC in the program is that we are interested in accessing the Clean Growth for Industry Fund (the Fund). FortisBC has established an internal committee tasked with identifying GHG reduction opportunities from its operations. As we evaluate options, the Fund will be key to expand the scope of what is possible. We also advocate that the Fund is accessible to address fugitive and vented emission sources, which can make up a large share of GHG emissions from a gas distribution and transmission system.

We also advocate for the fund to be sufficiently flexible to allow innovative projects and partnerships between industries and FortisBC. For example, we are identifying opportunities to work with other industries such as in chemicals or forestry to harness or produce renewable gases from waste products. These projects could directly reduce industrial plant emissions and should be eligible to receive support from the Fund.

While we understand and support the focus on early immediate GHG reduction actions, we also note that the Fund should also prioritize longer-term opportunities with sizeable emission reductions potential. FortisBC recently filed its Multi-Year Rate application with the BC Utilities Commission (BCUC). In the application, we are asking for a specific ratepayer-funded Innovation program of $5.5 million dollars to put toward demonstrating and commercializing critical low-carbon technologies required to cost-effectively achieve BC's GHG objectives. The Fund should be able to leverage FortisBC's prospective innovation program (should it receive BCUC approval). To this end, we recommend that the Fund should be designed to be leveraged with FortisBC's prospective Innovation program for projects to demonstrate early-stage technologies in the gas system that could reduce industrial GHG emissions.

4. Partner with FortisBC to leverage our existing industrial efficiency program

FortisBC is already a leading organization in reducing GHG emissions in BC's industry sector. We have committed over $2.5 million in 2019 to our industrial efficiency programs as part of our Demand-Side Management (DSM) activities governed under the DSM regulation. These programs provide funding for companies to adopt more efficient natural gas consuming equipment. FortisBC employees a team of skilled program administrators, engineers and other experts to evaluate projects including project design and business case analysis, market expertise, quality assurance, monitoring, and verification. Incentives are paid to industrial clients with a high confidence in the energy savings (and associated GHG emissions savings) as required by the BCUC.

Helping industrial customers improve the efficiency of their natural gas equipment and processes is one of the most cost-effective investments available to aggressively reduce GHG emissions while also reducing customer energy costs. This means that it is likely that the Fund will receive many applications for natural gas efficiency projects. Our goal is to ensure that both our DSM programs and the Fund are highly aligned and not competing with each other for projects. We envision a model similar to EfficiencyBC whereby MEMPR is the overall project lead but FortisBC is a key service provider. This approach utilizes our program infrastructure, to provide an integrated offering to the marketplace and to leverage FortisBC's DSM incentives. EfficiencyBC is embedded into our Commercial Performance Program creating a one-stop shop for participants. FortisBC develops the program terms and conditions, marketing materials and participant guidelines. FortisBC's Key Account Managers market the program and we use our internal engineering and evaluation staff to ensure key monitoring, verification and assurance.

We propose to formally explore a similar approach with CAS for industrial natural gas efficiency projects. A high-level model would be when applicants come to the Fund with efficiency projects, they are directed to FortisBC where will conduct initial project evaluation. For projects that may not satisfy the economic test using only FortisBC's incentives additional, top-up, incentives from the Fund would be applied. Conversely, FortisBC has already identified a number of projects in BC that do not satisfy our economic test. FortisBC could provide a queue of approximately 50 natural gas energy efficiency projects for top up from the Fund to hit-the-ground running.

We believe there is sizeable opportunity for alignment and that by working together we achieve each organization's objectives to maximize both participation in FortisBC's DSM programs and GHG emissions reductions in the industrial sector. But, in order to seize it we need to work closely with CAS. We envision a process similar to our engagement with MEMPR for EfficiencyBC; a series of workshops with internal

stakeholders, and collaboration between FortisBC and CAS on customer consultation, and program development are needed. We look forward to working with CAS on these issues and offer to come to Victoria and meet with yourself and CAS staff for consultations on how to proceed.

Sincerely,

Douglas L. Stout, Vice President

Market Development & External Relations
FortisBC

CC:

Les Maclaren – Assistant Deputy Minister, Ministry of Energy, Mines and Petroleum Resources

Neil Dobson – Executive Director, Clean Growth Climate Action Secretariat

Attachment 73.7

Year	Program	Expenditure Description	Expenditure ($000s)
2010	Solar Water Heating PSECA Program	Rebate program to encourage the adoption of solar water heating systems in provincial sector buildings to reduce natural gas consumption.	372
2010	Commercial NGV Demonstration Program	Rebate program to encourage the adoption of liquefied natural gas (LNG) and compressed natural gas (CNG) as a heavy duty vehicle fuel and to achieve environmental benefits to displacing diesel fuel	5589
2011	PSECA Solar Thermal	The BC Government, through the PSECA, is working with SolarBC to fund solar thermal water and air heating systems in provincial public sector buildings including schools, universities, colleges, hospitals, and Crown corporations.	350
2011	PSECA Solar Air	The BC Government, through PSECA, developed a program to fund solar thermal water and air heating systems in provincial public sector buildings including schools, universities, colleges, hospitals, and Crown corporations.	77
2011	SolarBC for Schools	Program initiated by SolarBC to encourage the adoption of solar water heating systems in schools to reduce natural gas consumption and increase awareness.	26
2011	COV Solar Residential Water Heating Pilot	Pilot project initiated by the City of Vancouver, Offsetters, and SolarBC to promote the installation of 30 Solar Hot Water system and gather real data and validate energy savings claims.	96
2011	Condo Retrofit Pilot	Pilot project initiated by the City of Vancouver to promote the installation of Variable Frequency Drive Ventilation Controls and Piping Insulation and Solar Thermal Hot Water for 15 Multi-Unit Residential Buildings (MURBs) within Vancouver.	401
2011	Occupancy Sensor Pilot	Partnership with the Burnaby School District #41 (SD#41) and Delta School District #37 (SD#37) to facilitate a "proof of concept" pilot study to validate energy saving claims of adding occupancy controls to unit ventilators to reduce energy costs associated with heating and lighting unoccupied classrooms.	40
2011	City of Courtenay Solar Pool Demonstration Project	Collaboration with the City of Courtenay to demonstrate Solar thermal pool heating on a highly attended and highly visible recreation facility in the center of downtown Courtenay.	45
2011	Westhouse Demonstration Project	Demonstration project initiated between the City of Vancouver and Simon Fraser University to demonstrate alternative energy in a high visibility collaboration and to gain information on the operation and energy performance of the solar thermal hot water system installed on a Laneway home in Vancouver.	11
2011	SPF Drying Energy Management System	Demonstration project initiated by BCHydro geared to validate energy savings claims by using improved process controls for lumber drying. BCHydro anticipates both electric and gas savings of 10% from a reduction in drying time and more precise drying control.	21
2012	Residential High Efficiency Water Heater Pilot	Pilot program is to obtain installation, performance and customer acceptance information regarding residential Domestic Hot Water ("DHW") technologies with an Efficiency Factor ("EF") of 0.80 or better.	198
2012	Energy Star .67 Storage Tank Water Heater Pilot	Pilot to determine the efficiency and savings of 0.67 EF and 0.70 EF water heaters by assessing their performance under various household profiles as well as understanding the installation concerns such as electrical wiring, space considerations and venting.	50
2012	AHU Coil Cleaning Pilot	Pilot to evaluate savings projections, understand potential technical barriers and explore both barriers and opportunities for market promotion with regards to Air Handling Unit (AHU) coil cleaning practices in hospitals. Gas savings are achieved through cleaner coils in the AHU, reducing the workload on the gas boiler that heats the hot water for the system.	5
2012	City of Courtenay Solar Pool Demonstration Project	Collaboration with the City of Courtenay to demonstrate Solar thermal pool heating on a highly attended and highly visible recreation facility in the center of downtown Courtenay.	16
2013	Residential High Efficiency Water Heater Pilot	Pilot program is to obtain installation, performance and customer acceptance information regarding residential Domestic Hot Water ("DHW") technologies with an Efficiency Factor ("EF") of 0.80 or better.	28
2013	Energy Star .67 Storage Tank Water Heater Pilot	Pilot to determine the efficiency and savings of 0.67 EF and 0.70 EF water heaters by assessing their performance under various household profiles as well as understanding the installation concerns such as electrical wiring, space considerations and venting.	13
2013	Ice Rink Resurfacing Efficiency Pilot	Pilot to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of vortex mechanical de-aerator technology for ice re-surfacing in British Columbia ice arenas.	322
2013	City of Courtenay Solar Pool Demonstration Project	Collaboration with the City of Courtenay to demonstrate Solar thermal pool heating on a highly attended and highly visible recreation facility in the center of downtown Courtenay.	12
2013	COV Solar Residential Water Heating Pilot	Pilot project initiated by the City of Vancouver, Offsetters, and SolarBC to promote the installation of 30 Solar Hot Water system and gather real data and validate energy savings claims.	3

Year	Program	Expenditure Description	Expenditure ($000s)
2013	Condensing Makeup air unit pilot	Pilot to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of vortex mechanical de-aerator technology for ice re-surfacing in British Columbia ice arenas.	286
2013	PSECA Solar	During the 2011 and 2012 period, the BC Government, through the PSECA was working with SolarBC to fund solar thermal water and air heating systems in provincial public sector buildings including schools, universities, colleges, hospitals and Crown corporations.	28
2014	COV Solar Residential Water Heating Pilot	Pilot project initiated by the City of Vancouver, Offsetters, and SolarBC to promote the installation of 30 Solar Hot Water system and gather real data and validate energy savings claims.	17
2014	Apartment Fireplace Efficiency Retrofit Pilot	Objectives of the pilot are to verify energy savings from replacing older decorative style “B” vented fireplaces with Direct Vent EnerChoice level heating style fireplaces in Multi Unit Residential Buildings (MURB’S).	44
2014	Condensing Makeup air unit pilot	Pilot to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of vortex mechanical de-aerator technology for ice re-surfacing in British Columbia ice arenas.	43
2014	Energy Star .67 Storage Tank Water Heater Pilot	Pilot to determine the efficiency and savings of 0.67 EF and 0.70 EF water heaters by assessing their performance under various household profiles as well as understanding the installation concerns such as electrical wiring, space considerations and venting.	11
2014	Ice Rink Resurfacing Efficiency Pilot	Pilot to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of vortex mechanical de-aerator technology for ice re-surfacing in British Columbia ice arenas.	27
2014	Combination Space and Water Heating System Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate.	8
2014	Residential High Efficiency Water Heater Pilot	Pilot program is to obtain installation, performance and customer acceptance information regarding residential Domestic Hot Water ("DHW") technologies with an Efficiency Factor ("EF") of 0.80 or better.	62
2015	Condensing Makeup air unit pilot	Pilot to validate energy savings claims, assess customer acceptance rates, and identify technical issues associated with the installation and operation of vortex mechanical de-aerator technology for ice re-surfacing in British Columbia ice arenas.	47
2015	Apartment Fireplace Efficiency Retrofit Pilot	Objectives of the pilot are to verify energy savings from replacing older decorative style “B” vented fireplaces with Direct Vent EnerChoice level heating style fireplaces in Multi Unit Residential Buildings (MURB’S).	140
2015	Combination Space and Water Heating System Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate.	222
2016	Heat Reflector Pilot	To assess energy savings, costing and customer acceptance data related to the installation of a Reflector Panel behind a perimeter heating system in rental MURBs.	28
2016	Apartment Fireplace Efficiency Retrofit Pilot	Objectives of the pilot are to verify energy savings from replacing older decorative style “B” vented fireplaces with Direct Vent EnerChoice level heating style fireplaces in Multi Unit Residential Buildings (MURB’S).	142
2016	Combination Space and Water Heating System Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate.	127
2017	Heat Reflector Pilot	To assess energy savings, costing and customer acceptance data related to the installation of a Reflector Panel behind a perimeter heating system in rental MURBs.	166
2017	Smart Learning Thermostat Pilot	This joint pilot between FortisBC Energy Inc. and FortisBC Inc. is designed to gauge the customer acceptance and energy savings associated with smart learning thermostats where the results will inform future Demand Side Management (DSM) program offerings. Smart Learning Thermostat (“SLT”) pilot focuses on the Nest, Ecobee3 and Honeywell Lyric products.	214
2017	Combination Space and Water Heating System Pilot	Objectives of the pilot are to identify field-validated energy performance of each combination system type, technical issues, field-validated incremental costs, customer acceptance and the effective marketing channels for promoting a combination system retrofit rebate.	53
2018	Carbon Capture Pilot	FEI partnered with CleanO2 to test and demonstrate energy efficiency and GHG reduction for carbon capture and conversion technology installations in the Lower Mainland and Vancouver Island. The pilot will test if the CleanO2 Carbon Capture Technology can meet the energy conservation and greenhouse gas (GHG) reductions objectives of commercial and small business clients.	144

Year	Program	Expenditure Description	Expenditure ($000s)
2018	Smart Learning Thermostat Pilot	This joint pilot between FortisBC Energy Inc. and FortisBC Inc. is designed to gauge the customer acceptance and energy savings associated with smart learning thermostats where the results will inform future Demand Side Management (DSM) program offerings. Smart Learning Thermostat ("SLT") pilot focuses on the Nest, Ecobee3 and Honeywell Lyric products.	91
2018	Gas Technology Demonstration Pilot	The Gas Technology Demonstration Pilot program provides funding to FortisBC Energy Specialists to explore innovative technologies through three main program offerings. Technology Feasibility Study, Technology Demonstration, Technology Measurement and Verification.	40
2018	On-Demand Recirculation Pilot	Objectives of the pilot is to verify the energy savings, customer acceptance and installation of on-demand recirculation controls for central domestic hot water recirculation systems. The pilot subscribed 19 rental apartment buildings located in the Lower Mainland of British Columbia.	107
2018	New Construction Como Unit Pilot	FortisBC conducted a pilot program for retrofit specific market on Combination systems. Although the pilot results were promising, they were only indicative of the retrofit market. The New Construction Combination Pilot will be conducted to assess the technical characteristics, market opportunity and projected energy savings of combination systems in new construction market. This project will target two townhome development projects located in FortisBC service territories.	44

Attachment 96.7

Targeted Incentives	Analysis Period (yrs)	NPV of Benefits ($000s)	NPV of Cost of Service Impact ($000s)	Gross Benefits/(Costs) ($000s)	NPV of Proposed Incentive - Equivalent BPS ($000s)	Net Impact to Customers Benefit/(Costs) ($000s)
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = (d) + (e)
Growth in Renewable Gas (RNG)	10	666,708	(536,315)	130,393	(10,088)	120,305
Growth in NGT	10	459,458	(40,171)	419,287	(10,088)	409,199
GHG Emissions Reduction (Customer)	15	282,714	(29,891)	252,823	(5,044)	247,780
GHG Emissions Reduction (Internal)	20	9,608	-	9,608	(5,044)	4,564

Targeted Incentives	Analysis Period (yrs)	NPV of Benefits ($000s)	NPV of Cost of Service Impact ($000s)	Gross Benefits/(Costs) ($000s)	NPV of Proposed Incentive - Equivalent BPS ($000s)	Net Impact to Customers Benefit/(Costs) ($000s)
Power Supply Incentive	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = (d) + (e)
High Range	5	90,630	-	90,630	(6,549)	84,081
Low Range	5	31,689	-	31,689	-	31,689

Targeted Incentive - RNG (FEI)

		Analysis Period (Yrs)	10											
Line	**Particular**	**Reference**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
							MRP							
1	MRP Target - RNG (TJ)	MRP Section C8.3.1			1,000	1,500	2,000	4,000	6,000					
2	Current RNG Volume (TJ)	MRP Section C8.3.1	342	342	342	342	342	342	342	342	342	342	342	342
3	Incremental MRP Target - RNG (TJ)	Line 1 - Line 2, Assume constant after MRP			658	1,158	1,658	3,658	5,658	5,658	5,658	5,658	5,658	5,658
4														
5	***Benefits ($000s)***													
6	Avoided Carbon Tax	Line 24			1,429	2,803	4,116	9,082	14,048	14,048	14,048	14,048	14,048	14,048
7	Avoided Electricity Cost	Line 52			5,943	10,634	15,902	36,603	59,010	61,451	63,940	66,479	69,070	71,711
8	Avoided Capital Cost of Conversion	Line 59			39,719	30,191	30,197	120,777	120,777	-	-	-	-	-
9	Total Annual Benefits	Sum of Line 6 to Line 8			47,091	43,629	50,215	166,462	193,835	75,499	77,988	80,528	83,118	85,760
10	PV of Annual Benefits	Line 9 / (1 + Line 13)^Yr			44,575	39,091	42,587	133,634	147,294	54,305	53,099	51,898	50,705	49,521
11	Total PV of Annual Benefits (From 2020)	Sum of Line 10			**666,708**									
12														
13	FEI WACC (After-Tax)	2019 Annual Review (G-19-10)			5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%
14														
15	***Costs ($000s)***													
16	Incremental Revenue Requirements - BPS	Line 73			2,372	2,372	2,372	2,372	2,372	-	-	-	-	-
17	Incremental Revenue Requirements - RNG Supply	Line 65			12,618	21,887	31,286	68,912	106,403	106,210	106,012	105,811	105,606	105,396
18	Total Incremental Revenue Requirements	Sum of Line 16 to Line 17			14,990	24,258	33,658	71,284	108,775	106,210	106,012	105,811	105,606	105,396
19	PV of Incremental Revenue Requirements	Line 18 / (1 + Line 13)^Yr			14,189	21,735	28,545	57,226	82,657	76,395	72,179	68,192	64,423	60,860
20	Total PV of Incremental Revenue Requirements	Sum of Line 19			**546,402**									
21														
22	***Assumptions - Avoided Carbon Tax***													
23	Carbon Tax - Natural Gas	April 1, 2019 @ $1.986/GJ	1.738	1.986	2.235	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483
24	Avoided Carbon Tax ($000s)	Line 3 x Line 23 (Jan - Mar from previous year)			1,429	2,803	4,116	9,082	14,048	14,048	14,048	14,048	14,048	14,048
25														
26	***Assumptions - Avoided Electricity Cost***													
27	FEI Residential Average Use per Year (GJ/yr)	90 GJ per year	90	90	90	90	90	90	90	90	90	90	90	90
28	Equivalent kWh	Line 27 x 277.78 x 0.8 (Assume 80% gas efficiency)	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
29	Equivalent Number of Homes (Fueled by RNG)	Line 3 / Line 27	-	-	7,308	12,863	18,419	40,641	62,863	62,863	62,863	62,863	62,863	62,863
30	Incremental Number of Homes		-	-	7,308	5,555	5,556	22,222	22,222	-	-	-	-	-
31														
32	BC Hydro - Residential Step 1 ($/kWh)	See Note 1		0.0945	0.0952	0.0971	0.0990	0.1010	0.1030	0.1051	0.1072	0.1093	0.1115	0.1137
33	BC Hydro - Residential Step 2 ($/kWh)	See Note 1		0.1417	0.1427	0.1456	0.1485	0.1515	0.1545	0.1576	0.1607	0.1639	0.1672	0.1706
34	Annual Increase (%)	See Note 1			0.72%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
35	Step 1 kWh per day	See Note 2	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918	22.1918
36	Equiv. Step 1 Electricity per home	1,351 kWh per 2 months (see Line 35)	8,106	8,106	8,106	8,106	8,106	8,106	8,106	8,106	8,106	8,106	8,106	8,106
37	Equiv. Step 2 Electricity per home	Line 28 - Line 36	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895
38	*Note 1 - F2020 (April 2019 to April 2020) per Interim Rate; F2021 rate increase per BCH RRA; assumed 2% thereafter (to be conservative)*													
39	*Note 2 -* https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/residential-rates.html													
40														
41	FEI - Residential Rates													
42	Annual Increase (%)				2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
43	Basic ($/yr)	$0.4085 per day		149	149	149	149	149	149	149	149	149	149	149
44	Delivery Rate ($/GJ)	Jan 1, 2019, assumed 2% annual increase		4.349	4.436	4.525	4.615	4.707	4.802	4.898	4.996	5.096	5.197	5.301
45	Cost of Gas ($/GJ)	Jan 1, 2019, assumed 2% annual increase		1.549	1.580	1.612	1.644	1.677	1.710	1.744	1.779	1.815	1.851	1.888
46	Midstream ($/GJ)	Jan 1, 2019, assumed 2% annual increase		1.462	1.491	1.521	1.551	1.583	1.614	1.646	1.679	1.713	1.747	1.782
47	Total RNG Rate (COG + CT + $7.00)	Line 45 + Line 23 + $7.00		10.535	10.815	11.095	11.127	11.160	11.193	11.227	11.262	11.298	11.334	11.371
48														
49	Total electricity cost per home ($/home/yr)	Line 32 x Line 36 + Line 33 x Line 37	-	2,451	2,469	2,518	2,569	2,620	2,673	2,726	2,781	2,836	2,893	2,951
50	Total RNG cost per home ($/home/yr)	Line 43 + Line 27 x (Line 44 + Line 46 + Line 47)	-	1,620	1,656	1,692	1,706	1,720	1,734	1,749	1,763	1,779	1,794	1,810
51	Avoided Electricity Premium per Home ($/home/yr)	Line 49 - Line 50	-	831	813	827	863	901	939	978	1,017	1,058	1,099	1,141
52	Total Avoided Electricity Premium ($000s)	Line 51 x Line 29	-	-	5,943	10,634	15,902	36,603	59,010	61,451	63,940	66,479	69,070	71,711
53														
54	***Assumptions - Avoided Capital Cost of Conversion***													
55	Capital Cost ($/Home) - Space Heating (Electric Baseboard)	FEI Long Term Gas Resourse Plan (LTGRP), Table 2-1			4,435	4,435	4,435	4,435	4,435					
56	Capital Cost ($/Home) - Water Heating (Electric Storage Tank)	FEI Long Term Gas Resourse Plan (LTGRP), Table 2-1			1,000	1,000	1,000	1,000	1,000					
57	Total Capital Premium ($/Home)	Avoided capital cost if RNG vs. converting to electricity			5,435	5,435	5,435	5,435	5,435					
58														
59	Total Avoided Capital Costs ($000s)	Line 29 x Line 57 / 1000 (Not cumulative)	-	-	39,719	30,191	30,197	120,777	120,777	-	-	-	-	-
60														
61	***Assumptions - Incremental Revenue Requirements - RNG Supply***													
62	FEI - Maximum RNG Supply Cost ($/GJ)	$30/GJ			30	30	30	30	30	30	30	30	30	30
63	FEI - BERC Rate (Cost to participants) ($/GJ)	Line 47			11	11	11	11	11	11	11	11	11	11
64	Delivery Rate Impact to non-bypass ($/GJ)	Line 63 - Line 62			19	19	19	19	19	19	19	19	19	19
65	Incremental Revenue Requirement - RNG Supply ($000s)	Line 64 x Line 3			12,618	21,887	31,286	68,912	106,403	106,210	106,012	105,811	105,606	105,396
66														
67	***Assumptions - Incremental Revenue Requirements - BPS***													
68	Rate Base ($000s)	2019 Approved (G-10-19)			4,496,946	4,496,946	4,496,946	4,496,946	4,496,946					
69	Equity Thickness	G-193-15			38.50%	38.50%	38.50%	38.50%	38.50%					
70	BPS - Targeted Incentive (RNG)	MRP Section C8.3, Table C8-1			10	10	10	10	10					
71	Equity Earnings ($000s)	Line 68 x Equity Thickness x BPS / 10000			1,731	1,731	1,731	1,731	1,731					
72	Income Taxes	Line 71 /(1+27%) x 27%			640	640	640	640	640					
73	Incremental Revenue Requirement - BPS ($000s)	Line 71 + Line 72			2,372	2,372	2,372	2,372	2,372					
74	PV of Incremental Revenue Requirement - BPS ($000s)	Line 73 / (1 + Line 13)^Yr			2,245	2,125	2,011	1,904	1,802					
75	Total PV of Incremental Revenue Requirement - BPS ($000s)	Sum of Line 74			10,088									

Targeted Incentive - NGT (FEI)

Analysis Period (Yrs) 10

Line	Particular	Reference		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
								MRP							
1	MRP Target - NGT (TJ)	MRP Section C8.3.2				3,000	4,000	5,000	6,000	7,000					
2	Current NGT Volume (TJ)	MRP Section C8.3.2		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
3	Incremental MRP Target - NGT (TJ)	Line 1 - Line 2, Assume constant after MRP				1,000	2,000	3,000	4,000	5,000	5,000	5,000	5,000	5,000	5,000
4															
5	Assumed CNG/LNG Ratio			10%											
6	CNG (TJ)			-	-	100	200	300	400	500	500	500	500	500	500
7	LNG (TJ)			-	-	900	1,800	2,700	3,600	4,500	4,500	4,500	4,500	4,500	4,500
8															
9	***Benefits ($000s)***														
10	Avoided Fuel Premium of Diesel	Line 44				6,153	12,688	19,363	26,267	33,407	33,993	34,590	35,199	35,820	36,453
11	Avoided Diesel Exhaust Fluid after Treatment	Line 52				2,590	5,180	7,770	10,360	12,950	12,950	12,950	12,950	12,950	12,950
12	Monetizing carbon credits	Line 76				2,548	5,096	7,644	10,192	12,740	12,740	12,740	12,740	12,740	12,740
13	Incremental Offsetting Delivery Margin	Line 86				3,800	7,752	11,860	16,130	20,566	20,977	21,396	21,824	22,261	22,706
14	Total Annual Benefits	Sum of Line 10 to Line 12				15,090	30,715	46,637	62,949	79,663	80,659	81,676	82,713	83,770	84,849
15	PV of Annual Benefits	Line 14 / (1 + Line 18)^Yr				14,284	27,521	39,553	50,534	60,535	58,017	55,609	53,306	51,103	48,995
16	Total PV of Annual Benefits (From 2020)	Sum of Line 15				**459,458**									
17															
18	FEI WACC (After-Tax)	2019 Annual Review (G-19-10)				5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%
19															
20	***Costs ($000s)***														
21	Incremental Revenue Requirements - BPS	Line 112				2,372	2,372	2,372	2,372	2,372	-	-	-	-	-
22	Incremental Revenue Requirements - Average NGT COS	Line 104				1,276	2,604	3,984	5,418	6,908	7,046	7,187	7,331	7,478	7,627
23	Total Incremental Revenue Requirements	Sum of Line 21 to Line 22				3,648	4,976	6,356	7,790	9,280	7,046	7,187	7,331	7,478	7,627
24	PV of Incremental Revenue Requirements	Line 23 / (1 + Line 18)^Yr				3,453	4,458	5,390	6,254	7,052	5,068	4,893	4,725	4,562	4,404
25	Total PV of Incremental Revenue Requirements	Sum of Line 24				**50,259**									
26															
27	***Assumptions - Avoided Fuel Premium of Diesel***														
28	Carbon Tax ($/tonne)			35	40	45	50	50	50	50	50	50	50	50	50
29	Carbon Tax - Diesel ($/Litre)	See Note 1		0.0895	0.1023	0.1151	0.1279	0.1279	0.1279	0.1279	0.1279	0.1279	0.1279	0.1279	0.1279
30	Carbon Tax - Diesel ($/GJ)	1 GJ = 25.9 DLE		2.318	2.649	2.980	3.312	3.312	3.312	3.312	3.312	3.312	3.312	3.312	3.312
31	Carbon Tax - Natural Gas	April 1, 2019 @ $1.986/GJ		1.738	1.986	2.235	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483
32															
33	Current Diesel Rack Rate, excl. Carbon Tax ($/Litre)	See Note 2 (May 23, 2019)			0.878										
34	Current Diesel Rack Rate, excl. Carbon Tax ($/GJ)	Line 33 x 25.9 + Annual Escalation			22.7402	23.195	23.659	24.132	24.615	25.107	25.609	26.121	26.644	27.177	27.720
35	Current Diesel Rack Rate, Incl. Carbon Tax ($/GJ)	Line 34 + Line 30			25.389	26.175	26.970	27.444	27.926	28.419	28.921	29.433	29.955	30.488	31.032
36															
37	Target NGT, Incl. Carbon Tax ($/DLE)				0.75										
38	Target NGT, Excl. Carbon Tax ($/GJ)	(Line 37 x 25.9) - Line 31 + Annual Escalation			17.44	17.788	18.144	18.506	18.877	19.254	19.639	20.032	20.433	20.841	21.258
39	Target NGT, Incl. Carbon Tax ($/GJ)	Line 38 + Line 31			19.425	20.023	20.627	20.989	21.360	21.737	22.122	22.515	22.916	23.324	23.741
40															
41	Annual Escalation	Assumed 2%				2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
42															
43	Avoided Fuel Premium of Diesel ($/GJ)	Line 35 - Line 39			5.964	6.153	6.344	6.454	6.567	6.681	6.799	6.918	7.040	7.164	7.291
44	Total Cumulative Avoided Fuel Premium of Diesel ($000s)	Line 43 x Line 3			-	6,153	12,688	19,363	26,267	33,407	33,993	34,590	35,199	35,820	36,453
45															
46	Note 1 - *https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/carbon-tax*														
47	Note 2 - *https://www.shell.ca/en_ca/business-customers/app-rack-pricing.html*														
48															
49	***Assumptions - Avoided Diesel Exhaust Fluid after Treatment***														
50	Avoided Diesel Exhaust fluid after treatment ($/DLE)	$0.1/Litre		0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
51	Avoided Diesel Exhaust fluid after treatment ($/GJ)	Line 50 x 25.9		2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59
52	Total Cumulative Avoided Diesel Exhaust Fluid ($000s)	Line 51 x Line 3			-	2,590	5,180	7,770	10,360	12,950	12,950	12,950	12,950	12,950	12,950
53															
54	***Assumptions - Monetizing carbon credits***														
55	Reference														
56	BC Renewable and Low Carbon Fuel Requirements Regulation - Compliance Report (2017)														
57															
58	Carbon Intensity Limit - CI Class (gCO2e/MJ)	CI Class													
59	CNG			90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02
60	LNG			90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02	90.02
61															
62	Energy Effectiveness Ratio - EER	EER													
63	CNG			0.9	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
64	LNG			1	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
65															
66	Carbon Intensity of Fuel - CI Fuel (gCO2e/MJ)	CI Fuel													
67	CNG			63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64
68	LNG			63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64	63.64
69															
70	Carbon Credit (Tonne)	(CI Class x EER - CI Fuel) x MJ / 100000													
71	CNG			-	-	1,738	3,476	5,213	6,951	8,689	8,689	8,689	8,689	8,689	8,689
72	LNG			-	-	23,742	47,484	71,226	94,968	118,710	118,710	118,710	118,710	118,710	118,710
73	Cumulative Total (Tonne)	Line 71 + Line 72		-	-	25,480	50,960	76,439	101,919	127,399	127,399	127,399	127,399	127,399	127,399
74															
75	Assumed Offset Credit ($/Tonne)			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
76	Cumulative Offset Credit ($000s)	Line 73 x Line 75		-	-	2,548	5,096	7,644	10,192	12,740	12,740	12,740	12,740	12,740	12,740
77															
78	***Assumptions - Incremental Offsetting Delivery Margin***														
79	Offseting Revenue	2019 Approved (G-10-19)													
80	CNG Delivery Effective Rate ($/GJ)		1.794		1.794	1.830	1.866	1.904	1.942	1.980	2.020	2.060	2.102	2.144	2.187
81	LNG RS46 Effective Delivery Rate ($/GJ)		3.940		3.940	4.019	4.099	4.181	4.265	4.350	4.437	4.526	4.616	4.709	4.803
82	*Assume 2% Annual Escalation*					2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
83															
84	CNG Delivery Margin			-	-	183	373	571	777	990	1,010	1,030	1,051	1,072	1,093
85	LNG Delivery Margin			-	-	3,617	7,379	11,289	15,353	19,575	19,967	20,366	20,774	21,189	21,613
86	TOTAL Offseting Delivery Margin (Benefits)			-	-	3,800	7,752	11,860	16,130	20,566	20,977	21,396	21,824	22,261	22,706
87															
88	***Assumptions - Incremental Revenue Requirements - Average NGT COS***														
89	NGT Station COS (2019 Forecast)														
90	Equity Return	2019 Approved (G-10-19)			2,083										
91	Debt Cost	2019 Approved (G-10-19)			1,001										
92	Amortization	2019 Approved (G-10-19)			1,809										
93	Income Tax	2019 Approved (G-10-19)			400										
94	O&M	2019 Approved (G-10-19)			2,339										
95	Subtotal - 2019 Forecast ($000s)	Sum of Line 90 to Line 94			7,632										
96	NGT Station Revenue (2019 Forecast)	2019 Approved (G-10-19)			(4,378)										
97	TOTAL NGT Station Incremental Revenue Requirement ($000s)	Line 95 + Line 96			3,254										
98															
99	NGT Demand (2019 Forecast), TJ	2019 Approved (G-10-19)			2,600										
100															
101	Average NGT Station Rate ($/GJ)	Line 97 / Line 99			1.251	1.276	1.302	1.328	1.355	1.382	1.409	1.437	1.466	1.496	1.525
102	*Assume 2% Annual Escalation*					2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
103															
104	*Average NGT Station Costs ($000s)*			-	-	1,276	2,604	3,984	5,418	6,908	7,046	7,187	7,331	7,478	7,627
105															
106	***Assumptions - Incremental Revenue Requirements - BPS***														
107	Rate Base ($000s)	2019 Approved (G-10-19)				4,496,946	4,496,946	4,496,946	4,496,946	4,496,946					
108	Equity Thickness	G-193-15				38.50%	38.50%	38.50%	38.50%	38.50%					
109	BPS - Targeted Incentive (RNG)	MRP Section C8.3, Table C8-1				10	10	10	10	10					
110	Equity Earnings ($000s)	Line 107 x Equity Thickness x BPS / 10000				1,731	1,731	1,731	1,731	1,731					
111	Income Taxes	Line 110 /(1+27%) x 27%				640	640	640	640	640					
112	Incremental Revenue Requirement - BPS ($000s)	Line 110 + Line 111				2,372	2,372	2,372	2,372	2,372					
113	PV of Incremental Revenue Requirement - BPS ($000s)	Line 112 / (1 + Line 18)^Yr				2,245	2,125	2,011	1,904	1,802					
114	Total PV of Incremental Revenue Requirement - BPS ($000s)	Sum of Line 113				10,088									

Targeted Incentive - GHG Reduction (FEI Customer)

Line	Particular	Reference	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
		Analysis Period (Yrs)	15																
							MRP												
1	MRP Target - Number of Conversion	MRP Section C8.3.3			2,700	2,700	2,700	2,700	2,700										
2	Cumulative MRP Target - Conversion				2,700	5,400	8,100	10,800	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500
3																			
4	***Benefits ($000s)***																		
5	Avoided Commodity Premium	Line 58			4,561	9,452	14,438	19,604	24,955	25,413	25,881	26,359	26,846	27,343	27,849	28,366	28,893	29,431	29,979
6	Incremental Offsetting Delivery Margin	Line 68			1,481	3,004	4,572	6,186	7,847	7,964	8,083	8,204	8,328	8,454	8,583	8,714	8,848	8,985	9,124
7	Total Annual Benefits	Sum of Line 5 to Line 6			6,042	12,457	19,010	25,790	32,801	33,377	33,964	34,563	35,174	35,797	36,432	37,080	37,741	38,416	39,104
8	PV of Annual Benefits	Line 7 / (1 + Line 11)^Yr			5,719	11,161	16,123	20,704	24,926	24,008	23,125	22,275	21,457	20,670	19,913	19,184	18,483	17,808	17,158
9	Total PV of Annual Benefits (From 2020)	Sum of Line 8			**282,714**														
10																			
11	FEI WACC (After-Tax)	2019 Annual Review (G-19-10)			5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%
12																			
13	***Costs ($000s)***																		
14	Incremental Revenue Requirements - BPS	Line 80			1,186	1,186	1,186	1,186	1,186	-	-	-	-	-	-	-	-	-	-
15	Incremental Revenue Requirements - New Additions	Line 72			121	1,049	1,864	2,695	3,534	4,111	4,079	4,042	3,997	3,950	3,901	3,851	3,799	3,745	3,705
16	Total Incremental Revenue Requirements	Sum of Line 14 to Line 15			1,307	2,235	3,050	3,881	4,720	4,111	4,079	4,042	3,997	3,950	3,901	3,851	3,799	3,745	3,705
17	PV of Incremental Revenue Requirements	Line 16 / (1 + Line 11)^Yr			1,237	2,003	2,586	3,116	3,587	2,957	2,777	2,605	2,438	2,281	2,132	1,992	1,860	1,736	1,626
18	Total PV of Incremental Revenue Requirements	Sum of Line 17			**34,934**														
19																			
20	***Assumptions - Avoided Commodity Premium***																		
21	Assumed Heating Oil/Propane Ratio																		
22	Heating Oil	BC CPR		64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%	64%
23	Propane	BC CPR		36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
24																			
25	Heating Oil Conversion	Line 2 x Line 22		-	1,728	3,456	5,184	6,912	8,640	8,640	8,640	8,640	8,640	8,640	8,640	8,640	8,640	8,640	8,640
26	Propane Conversion	Line 2 x Line 23		-	972	1,944	2,916	3,888	4,860	4,860	4,860	4,860	4,860	4,860	4,860	4,860	4,860	4,860	4,860
27																			
28	Average FEI Residential Use per year		90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
29																			
30	Heating Oil Price, Excl. Carbon Tax ($/Litre)	See Note 1; Weekly (May 21), Avg. Vancouver, Victoria, Kamloops		1.208	1.232	1.257	1.282	1.308	1.334	1.360	1.388	1.415	1.444	1.473	1.502	1.532	1.563	1.594	1.626
31	Heating Oil Carbon Tax ($/Litre)	See Note 2		0.102	0.115	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128	0.128
32	Heating Oil, Incl. Carbon Tax ($/Litre)	Line 30 + Line 31		1.310	1.347	1.385	1.410	1.435	1.462	1.488	1.515	1.543	1.572	1.600	1.630	1.660	1.691	1.722	1.754
33	Heating Oil, Incl. Carbon Tax ($/GJ)	1 GJ = 1000/36.72 Litre		35.683	36.689	37.709	38.393	39.091	39.804	40.530	41.271	42.027	42.798	43.584	44.386	45.204	46.039	46.890	47.758
34	*Annual Escalation (Heating Oil)*				2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
35	Total Heating Oil per home per year ($/Home/Yr)	Line 33 x Line 28		3,211	3,302	3,394	3,455	3,518	3,582	3,648	3,714	3,782	3,852	3,923	3,995	4,068	4,143	4,220	4,298
36																			
37	Propane Price ($/GJ)	2019 Q1 FEI Revelstoke Gas Cost Report (Excl. PCDA and Carbon Tax) + Annual Escalation		9.4698	9.659	9.852	10.049	10.250	10.455	10.665	10.878	11.095	11.317	11.544	11.775	12.010	12.250	12.495	12.745
38	Propane, Carbon Tax ($/GJ)	See Note 2		2.407	2.708	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009	3.009
39	Total Propane Price ($/GJ)	Line 37 + Line 38		11.877	12.367	12.861	13.058	13.259	13.464	13.674	13.887	14.104	14.326	14.553	14.784	15.019	15.259	15.504	15.754
40	*Annual Escalation (Propane)*				2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
41	Total Propane per home per year ($/Home/Yr)	Line 39 x Line 28		1,069	1,113	1,158	1,175	1,193	1,212	1,231	1,250	1,269	1,289	1,310	1,331	1,352	1,373	1,395	1,418
42																			
43	FEI - Residential Rates																		
44	Annual Increase (%)				2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
45	Basic ($/yr)	$0.4085 per day		149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
46	Delivery Rate ($/GJ)	Jan 1, 2019, assumed 2% annual increase		4.349	4.436	4.525	4.615	4.707	4.802	4.898	4.996	5.096	5.197	5.301	5.407	5.516	5.626	5.738	5.853
47	Cost of Gas ($/GJ)	Jan 1, 2019, assumed 2% annual increase		1.549	1.580	1.612	1.644	1.677	1.710	1.744	1.779	1.815	1.851	1.888	1.926	1.965	2.004	2.044	2.085
48	Midstream ($/GJ)	Jan 1, 2019, assumed 2% annual increase		1.462	1.491	1.521	1.551	1.583	1.614	1.646	1.679	1.713	1.747	1.782	1.818	1.854	1.891	1.929	1.968
49	Total 100% NG per home per year ($/Home/Yr)	Line 45 + Line 28 x (Sum of Line 46 to Line 48)		812	825	838	852	866	880	895	910	925	941	957	973	989	1,006	1,023	1,041
50																			
51	Avoided Premium																		
52	Heating Oil - NG ($/Home/Yr)	Line 35 - Line 49		2,400	2,477	2,556	2,603	2,652	2,702	2,753	2,804	2,857	2,911	2,966	3,022	3,079	3,137	3,197	3,258
53	Propane - NG ($/Home/Yr)	Line 41 - Line 49		257	288	319	323	327	331	336	340	344	349	353	358	363	367	372	377
54																			
55	Cumulative Avoided Premium																		
56	Heating Oil ($000s)	Line 52 x Line 25 / 1000		-	4,281	8,832	13,496	18,331	23,344	23,783	24,230	24,686	25,152	25,626	26,110	26,604	27,108	27,622	28,146
57	Propane ($000s)	Line 53 x Line 26 / 1000		-	280	621	942	1,272	1,610	1,631	1,652	1,673	1,694	1,716	1,739	1,762	1,785	1,809	1,834
58	TOTAL ($000s)	Line 56 + Line 57		-	4,561	9,452	14,438	19,604	24,955	25,413	25,881	26,359	26,846	27,343	27,849	28,366	28,893	29,431	29,979
59																			
60	Note 1 - https://charting.kentgroupltd.com/																		
61	Note 2 - https://www2.gov.bc.ca/assets/gov/taxes/sales-taxes/publications/mft-ct-005-tax-rates-fuels.pdf																		
62																			
63	***Assumptions - Incremental Offsetting Delivery Margin***																		
64	FEI - Residential Rates																		
65	Basic ($/yr)	Line 45		149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
66	Delivery Rate ($/GJ)	Line 46		4.349	4.436	4.525	4.615	4.707	4.802	4.898	4.996	5.096	5.197	5.301	5.407	5.516	5.626	5.738	5.853
67	Offseting Delivery Revenue per Home ($/Home/Yr)	Line 65 + Line 28 x Line 66		541	548	556	564	573	581	590	599	608	617	626	636	646	655	666	676
68	TOTAL Offseting Delivery Margin ($000s)			-	1,481	3,004	4,572	6,186	7,847	7,964	8,083	8,204	8,328	8,454	8,583	8,714	8,848	8,985	9,124
69																			
70	***Assumptions - Incremental Revenue Requirements - New Additions***																		
71	Incremental Cost of Service ($000s)	COS Model - New Additions			121	1,049	1,864	2,695	3,534	4,111	4,079	4,042	3,997	3,950	3,901	3,851	3,799	3,745	3,705
72		Analysis Period Only			121	1,049	1,864	2,695	3,534	4,111	4,079	4,042	3,997	3,950	3,901	3,851	3,799	3,745	3,705
73																			
74	***Assumptions - Incremental Revenue Requirements - BPS***																		
75	Rate Base ($000s)	2019 Approved (G-10-19)			4,496,946	4,496,946	4,496,946	4,496,946	4,496,946										
76	Equity Thickness	G-193-15			38.50%	38.50%	38.50%	38.50%	38.50%										
77	BPS - Targeted Incentive (RNG)	MRP Section C8.3, Table C8-1			5	5	5	5	5										
78	Equity Earnings ($000s)	Line 75 x Equity Thickness x BPS / 10000			866	866	866	866	866										
79	Income Taxes	Line 78 /(1+27%) x 27%			320	320	320	320	320										
80	Incremental Revenue Requirement - BPS ($000s)	Line 78 + Line 79			1,186	1,186	1,186	1,186	1,186										
81	PV of Incremental Revenue Requirement - BPS ($000s)	Line 80 / (1 + Line 11)^Yr			1,122	1,062	1,006	952	901										
82	Total PV of Incremental Revenue Requirement - BPS ($000s)	Sum of Line 81			5,044														

Targeted Incentive - GHG Reduction (FEI Internal)

	Analysis Period (Yrs)	20																					
Line	**Particular**	**Reference**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
							MRP																	
1	MRP Target - Emissions Intensity Reduction (tCO2e/PJ)				10	10	10	10	10															
2	Cumulative MRP Target - Emission Intensity Reduction (tCO2e/PJ)	MRP Section C8.3.4			10	20	30	40	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
3																								
4	Load Forecast (TJ) - non-Bypass + own Use	2019 Annual Review (G-19-10); held constant beyond 2024		202,319	206,139	209,448	212,412	215,505	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934	218,934
5	Emission Reduction Target (tCO2e)	Line 4 x Line 2 / 1000		-	2,061	4,189	6,372	8,620	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947	10,947
6																								
7	***Benefits ($000s)***															500	550	600	650	700	750	800	850	900
8	Avoided Carbon Tax	Line 26			93	209	319	431	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
9	Avoided Cost of Gas	Line 34			66	136	211	291	377	385	392	400	408	416	425	433	442	451	460	469	478	488	497	507
10	Total Annual Benefits	Sum of Line 8 to Line 9			158	345	530	722	924	932	940	947	955	964	972	980	989	998	1,007	1,016	1,025	1,035	1,045	1,055
11	PV of Annual Benefits	Line 10 / (1 + Line 14)^Yr			150	309	449	580	702	670	640	611	583	556	531	507	484	463	442	422	403	385	368	352
12	Total PV of Annual Benefits (From 2020)	Sum of Line 11			9,608																			
13																								
14	FEI WACC (After-Tax)	2019 Annual Review (G-19-10)			5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%
15																								
16	***Costs ($000s)***																							
17	Incremental Revenue Requirements - BPS	Line 42			1,186	1,186	1,186	1,186	1,186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Total Incremental Revenue Requirements	Sum of Line 17 to Line 17			1,186	1,186	1,186	1,186	1,186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	PV of Incremental Revenue Requirements	Line 18 / (1 + Line 14)^Yr			1,122	1,062	1,006	952	901	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total PV of Incremental Revenue Requirements	Sum of Line 19			5,044																			
21																								
22	***Assumptions - Avoided Carbon Tax***																							
23	Carbon Tax - Natural Gas ($/tonne)		35	40	45	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
24	Carbon Tax - Natural Gas ($/GJ)	April 1, 2019 @ $1.986/GJ	1.738	1.986	2.235	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483	2.483
25																								
26	Avoided Carbon Tax ($000s)	Line 23 x Line 5 / 1000		-	93	209	319	431	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
27																								
28	***Assumptions - Avoided Cost of Gas***																							
29	Equivalent Natural Gas Loss Reduction (TJ)	Line 26 / Line 24		-	42	84	128	174	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
30																								
31	FEI - Cost of Gas Rates																							
32	Cost of Gas ($/GJ)	Jan 1, 2019, assumed 2% annual increase		1.549	1.580	1.612	1.644	1.677	1.710	1.744	1.779	1.815	1.851	1.888	1.926	1.965	2.004	2.044	2.085	2.126	2.169	2.212	2.257	2.302
33	Annual Increase (%)				2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
34	TOTAL Avoided Cost of Gas ($000s)	Line 32 x Line 29		-	66	136	211	291	377	385	392	400	408	416	425	433	442	451	460	469	478	488	497	507
35																								
36	***Assumptions - Incremental Revenue Requirements - BPS***																							
37	Rate Base ($000s)	2019 Approved (G-10-19)			4,496,946	4,496,946	4,496,946	4,496,946	4,496,946															
38	Equity Thickness	G-193-15			38.50%	38.50%	38.50%	38.50%	38.50%															
39	BPS - Targeted Incentive (RNG)	MRP Section C8.3, Table C8-1			5	5	5	5	5															
40	Equity Earnings ($000s)	Line 37 x Equity Thickness x BPS / 10000			866	866	866	866	866															
41	Income Taxes	Line 40 /(1+27%) x 27%			320	320	320	320	320															
42	Incremental Revenue Requirement - BPS ($000s)	Line 40 + Line 41			1,186	1,186	1,186	1,186	1,186															
43	PV of Incremental Revenue Requirement - BPS ($000s)	Line 42 / (1 + Line 14)^Yr			1,122	1,062	1,006	952	901															
44	Total PV of Incremental Revenue Requirement - BPS ($000s)	Sum of Line 43			5,044																			

Targeted Incentive - Power Supply Incentive (FBC)

Line	Particular	Reference	2020	2021	2022	2023	2024
					MRP		
1	***Benefits ($000s)***						
2							
3	***High Range***						
4	PSI Customer Share	Line 30	21,450	21,450	21,450	21,450	21,450
5	PV of Annual Benefits	Line 4 / (1 + Line 13)^Yr	20,257	19,131	18,067	17,062	16,113
6	Total PV of Annual Benefits (From 2020)	Sum of Line 5	**90,630**				
7							
8	***Low Range***						
9	PSI Customer Share	Line 35	7,500	7,500	7,500	7,500	7,500
10	PV of Annual Benefits	Line 9 / (1 + Line 13)^Yr	7,083	6,689	6,317	5,966	5,634
11	Total PV of Annual Benefits (From 2020)	Sum of Line 10	**31,689**				
12							
13	FBC WACC (After-Tax)	2019 Annual Review (G-246-18)	5.89%	5.89%	5.89%	5.89%	5.89%
14							
15	***Costs ($000s)***						
16							
17	***High Range***						
18	PSI FBC Share	Line 31	1,550	1,550	1,550	1,550	1,550
19	PV of Incremental Revenue Requirements	Line 18 / (1 + Line 13)^Yr	1,464	1,382	1,306	1,233	1,164
20	Total PV of Incremental Revenue Requirements	Sum of Line 19	**6,549**				
21							
22	***Low Range***						
23	PSI FBC Share	Line 36	-	-	-	-	-
24	PV of Incremental Revenue Requirements	Line 23 / (1 + Line 13)^Yr	-	-	-	-	-
25	Total PV of Incremental Revenue Requirements	Sum of Line 24	**-**				
26							
27	***Assumptions - PSI Customer Share***						
28	*High Range*						
29	Estimated Mitigation - High Range ($000s)	Estimated based on 2018 Actual	23,000	23,000	23,000	23,000	23,000
30	Customer Share	$7.5M + 0.9 x (Total Mitigation - $7.5M)	21,450	21,450	21,450	21,450	21,450
31	FBC Share	Total mitigation - Customer Share	1,550	1,550	1,550	1,550	1,550
32							
33	*Low Range*						
34	Estimated Mitigation - Low Range ($000s)	Estimated based on 2014 Actual	7,500	7,500	7,500	7,500	7,500
35	Customer Share	$7.5M + 0.9 x (Total Mitigation - $7.5M)	7,500	7,500	7,500	7,500	7,500
36	FBC Share	Total mitigation - Customer Share	-	-	-	-	-