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June 17, 2019

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

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 Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

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

A number of the IRs requested copies of engineering reports which FortisBC has requested be 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. FortisBC requests that these documents be kept confidential as they contain sensitive technical information pertaining to FBC's assets which, if publicly released, may jeopardize the safety and security of FortisBC's assets. FortisBC has no objection to interveners obtaining copies of these confidential documents upon execution of the BCUC's Confidentiality Declaration and Undertaking Form.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.
FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, page A-5, lines 19-22 and Footnote #1

Exhibit B-1, pages A-6 to A-7, Figures A1-1 and A1-2

1.1 Please provide schedules setting out the deviation/basis for the $285, $314 and $286 values referenced in Footnote #1 for FEI.

<u>Response:</u>

Please refer to Attachment 1.1 for an Excel file with formulae intact for the detailed calculations of the data in Footnote 1 and Footnote 115.

The schedule shows the FEI and FBC Historical, Projected and Base O&M per Customer in both nominal and inflation adjusted basis. The schedule includes the Total O&M including Flow Through items, Actual Formula O&M, average number of customers and inflation factor that formed the basis for calculating the values referenced in Footnote #1 for FEI and FBC.

The FBC Total O&M per Customer (inflation adjusted) of $426 for 2018 changed slightly from the Total O&M per Customer of $429 as depicted in Figure B2-2 as the 2018 O&M Actual used in the graph was based on a preliminary number.

1.2 Please provide schedules setting out the derivation/basis for the $439, $495 and $457 values referenced in Footnote #1 for FBC.

<u>Response:</u>

Please refer to the response to BCOAPO IR 1.1.1.

1.3 Please explain the difference between the 2019P and 2019B values shown in Figures A1-1 and A1-2 (i.e., what do each represent?).

<u>Response:</u>

In Figures A1-1 and A1-2, the 2019P values represent the 2019 Projected O&M as per the Current PBR Plan and the 2019B values represent the 2019 Base O&M, which is the starting point for determining O&M for the Proposed MRPs. The 2019B consists of the adjusted actual O&M expenditures for 2018, escalated by the approved formula inflation factors for 2019 and adjusted for flow-throughs for 2019. It also includes the new funding required for the MRP term.

Please refer to Section C2.4: FEI O&M Base in the Application for further discussion.

The stated O&M values are on a Net O&M basis, which is calculated as Total O&M less the biomethane transferred to BVA and capitalized overhead. The capitalized overhead rate used in the 2019B value for FEI is the proposed 16 percent.

1.4 Please reconcile the 2019 O&M values referenced for FEI in Footnote #1 with those shown in Figure A1-1.

Response:

The primary difference between the two sets of 2019 values referenced is due to the inclusion of capitalized overhead in Figure A1-1 which converts the Gross O&M to a Net O&M basis (2019P reflects existing 12 percent overhead rate, 2019B reflects proposed 16 percent overhead rate).

The 2019 O&M values referenced for FEI in Footnote #1 represent, on an inflation-adjusted basis, the 2019 Gross Total O&M per customer ($285 per customer) and the 2019 Gross Formula Base O&M per customer ($250). Both 2019 O&M values are for the 2019B.

The 2019 O&M values reported in Figure A1-1 represent, on an inflation-adjusted basis, the 2019 Net Total O&M per customer ($238 per customer) for 2019P and 2019B. The 2019B includes the adjustments and proposed incremental funding and incorporates the estimated impact of increasing the capitalized overhead rate to 16 percent from 12 percent.

1.5 Please reconcile the 2019 O&M values referenced for FBC in Footnote #1 with those shown in Figure A1-2.

Response:

The primary difference between the two sets of 2019 values referenced is due to the inclusion of capitalized overhead in Figure A1-2 which converts the Gross O&M to a Net O&M basis. The

Net O&M in both 2019 Projected and Base in Figure A1-2 is calculated as Total O&M less 15 percent capitalized overhead.

The 2019 O&M values referenced for FBC in Footnote #1 represent, on an inflation-adjusted basis, the 2019 Gross Total O&M per customer ($439 per customer) and the 2019 Gross Formula Base O&M per customer ($416 per customer). Both 2019 O&M values are for the 2019B.

The 2019 O&M values reported in Figure A1-2 represent, on an inflation-adjusted basis, the 2019 Net Total O&M per customer of $359 and $373 per customer for 2019P and 2019B, respectively. The 2019B includes the adjustments and proposed incremental funding.

2.0 Reference: Exhibit B-1, page A-6, Figure A1-1, Footnote 2 for FEI, and Exhibit B-1-1, Appendix A2-1, and Appendix A3-1 O&M History (FEI)

2.1 Please confirm that the Total Gross O&M spending for the years 2013-18 inclusive shown in Appendix A2-1 and Appendix A3-1 are in nominal dollars; if unable to confirm, please explain.

Response:

Confirmed.

2.2 Please confirm that the "real dollars" referred to on the referenced figure (A1-1) are "2019 dollars"; if unable to so confirm, please clarify which year's dollars are real dollars.

Response:

Confirmed.

2.3 For each year, please provide the annual factors used – and their derivation – to convert the nominal dollars for the year into real dollars for Figure A1-1.

Response:

Please refer to Attachment 1.1 provided in the response to BCOAPO IR 1.1.1.

2.4 Please provide the number of customers used to calculate O&M per customer for 2019 and indicate whether the referenced figure represents projected average number or projected year-end customers.

Response:

As indicated on line 4 of page C-19, FEI used 1,024,962 as the projected average number of customers for calculating the O&M per customer for 2019.

2.5 If the data is available, please augment Appendix A3-1 to include actuals for 2018 and projected for 2019. If it is not yet available, please indicate when the Utility expects it will be.

Response:

Please refer to the response to BCUC IR 1.23.1.

3.0 Reference: Exhibit B-1, page A-6, Figure A1-1, page B-32 Figure B2-1 and Footnote 48

3.1 Please reconcile the figures shown for FEI actual net O&M (real) shown in Figure A1-1 with the figures shown for FEI actual O&M (real) shown in Figure B2-1 – the differences do not appear to be entirely due to overhead capitalization.

<u>Response:</u>

The difference is due to overheads capitalized and the costs of biomethane transferred to the BVA.

4.0 Reference: Exhibit B-1, page A-9, Table A1-2

4.1 Please provide a table showing the actual capital spending undertaken by FEI in nominal dollars for each year 2014-2019 inclusive.

Response:

The reference is to the 2020-2024 forecasts for Sustainment and Other Capital. Therefore, the response has been prepared in reference to only that capital (and not total capital).

Please refer to Table C3-4 on Page C-63 of the Application showing actual Sustainment and Other capital expenditures for the 2014-2019 period. For ease of reference, the table has been reproduced below:

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**

5.0 Reference: Exhibit B-1, page A-12, including Table A1-5

5.1 With respect to Table A1-5, under the "Responsive to Customer Expectations" feature please explain what is meant by cost-effective.

Response:

Cost effective refers to the focus of the Clean Growth Innovation Fund being on initiatives that will result in commercial solutions which are cost-effective from a customer perspective. Cost-effectiveness in this context means the lowest reasonable cost for clean products and services offered by FortisBC to its customers, and also considers solutions that maintain or increase load to keep rates affordable for customers.

5.1.1 In particular, does it mean that the focus of the Fund will be on initiatives that are cost-effective from a ratepayer perspective (i.e., will reduce overall charges paid by ratepayers to the respective utilities?).

Response:

Please refer to the response to BCOAPO IR 1.5.1.

5.1.2 Will all the individual initiatives pursued using monies from this fund be "cost-effective" in their own rights from rate payer perspective?

Response:

Please refer to the response to BCOAPO IR 1.5.1.

5.2 Please explain how interested parties will be able to verify the efficacy of the utility's spending from the Clean Growth Innovation Fund ex post in order to ascertain whether the fund delivers real benefits to ratepayers.

Response:

As noted in Section C6.6 of the Application, FortisBC will provide an annual update on the progress on approved projects as part of the Annual Reviews. This information will assist interested parties as to the initiatives completed and results achieved.

As the response to BCUC IR 1.80.1 indicates, measuring success of the Clean Growth Innovation Fund is likely to involve more than just accomplishing the goals of a particular initiative. Ultimately, a particular avenue of investigation is successful if it contributes to the commercialization of a product or service that helps FortisBC achieve the goals established for the Clean Growth Innovation Fund. This may or may not happen within the MRP term, but FortisBC will report on any activities that do.

5.3 Regarding the feature "Responsive to customer expectations," will the utilities be surveying ratepayers or do the utilities have some other method or metric to determine whether the utility has been successful in this respect?

Response:

No. In Table A1-5, "Responsive to Customer Needs" refers to the design of the Clean Growth Innovation Fund and not its outcome. However, the success of the Clean Growth Innovation Fund as well as other features of FortisBC's service will be measured by both the level of adoption of related service offerings and the level of customer satisfaction. FortisBC's understanding is that the development of new or enhanced service offerings, particularly cleaner service offerings, is something that customers are interested in.

Please also refer to the response to CEC IR 1.33.2.

5.4 Please provide a list of concrete examples as to how the utilities intend to be increasingly "responsive to customer expectations" or provide a reference in the evidence as to where such examples can be found.

Response:

FortisBC believes that customers expect the utility to provide them with clean energy, which is a focus of the Clean Growth Innovation Fund. In addition, the Fund will look for research, development and demonstration opportunities in non-DSM end-use technologies that will provide customers with additional end-use options. Finally, the Clean Growth Innovation Fund will support customers' use of clean transportation, which is continuing to grow. Please also refer to Appendix C6-4 of the Application.

5.5 Is it the utilities' view that the features listed in the referenced table are currently not being addressed or being addressed insufficiently?

Response:

The features listed in Table A1-5 refers to aspects of the design of the Clean Growth Innovation Fund. This does not imply that these features are not desirable, or lacking, in other activities that FortisBC undertakes.

5.6 Do the utilities regard the features listed in the referenced table as not being normally what ratepayers would expect to be the responsibility of the utility in the prudent management of its affairs? In other words, are any of the features "new" in any sense?

Response:

Please refer to the response to BCOAPO IR 1.5.5.

6.0 Reference: Exhibit B-1, page A-15, lines 4-11

6.1 Please provide specific examples of Canadian jurisdictions that have approved "targeted incentives".

Response:

Please refer to the response to BCUC IR 1.96.4.

6.2 Please provide relevant references for these specific examples which outline the nature of these incentives and their approvals.

Response:

Please refer to the response to BCUC IR 1.96.4.

7.0 Reference: Exhibit B-1-1, Appendix B-6, Tables A:B6-1 – B6-8

7.1 Please indicate which of the PBR initiatives the utilities would not have undertaken over the period 2014-19 had they been regulated under cost of service regulation for that period. If these differ for each utility, please provide separate answers to reflect the preferences of each utility. For example, as described in Table A:6-4, the utility reviewed the contract with its technical and infrastructure provider, issued an RFP, and changed its supplier. Is this not an exercise – regular review of third-party agreements – that one would expect from any prudent utility to undertake regardless of the form of regulation under which it operates?

Response:

For this response, FortisBC references its response to MoveUP IR 1.2.2 submitted as part of the FEI Annual Review for 2019 Rates[1] which similarly asked whether FEI would have pursued initiatives and achieved O&M savings depending on whether it was regulated under the Current PBR Plan or cost of service.

REFERENCE: Exhibit B-2 page 4 section 1.4. Overview of O&M Savings

Net ratepayer gains from PBR

2.2 Please identify the savings and efficiencies that have been achieved for ratepayers since the inception of the PBR Plan that have been a direct result of the PBR – i.e., that would not have been achieved in the absence of the incentive mechanisms and other features of the PBR plan.

Response:

FEI believes that the savings and efficiencies achieved to date have been driven in full or in part by the incentive mechanisms and other features of the PBR Plan, including the six-year test period. However, FEI cannot know what it would have done in the hypothetical situation in which FEI was under forecast cost of service ratemaking over the same time period. As such, FEI cannot identify the portion of savings and efficiencies achieved to date that would not have been achieved in the absence of the incentive mechanisms and other features of the PBR Plan.

While it is impossible to answer the hypothetical question posed, one of the features of the PBR Plan is that it extended the period before rebasing. This

[1] A similar response was provided to MoveUP IR 1.3.2 in FBC's Annual Review for 2019 Rates.

allowed FEI to invest in measures and obtain a payback of investment in circumstances where rebasing after a typical test period of one or two years would otherwise preclude the utility from recovering that investment. Some of the Major Initiatives with an efficiency aspect outlined in Appendix C2 of the Application have a longer payback time horizon and therefore are unlikely to have been pursued in the same timeframe in a forecast cost of service ratemaking regime where rebasing occurs in one or two years.

Further, the current PBR Plan has generated benefits to both customers and the Company. The two most common cited benefits of a PBR plan are its effectiveness in incenting a utility to capture efficiencies and to promote regulatory efficiency. FEI believes it has delivered both these benefits to date in its current PBR Plan while maintaining service quality. For example, annual increases to O&M funding have been limited to inflation and customer growth factors, and also met or exceeded the productivity factor that represents a minimum level of efficiency benefits that flow to customers. Delivery rates have remained flat over the past two years and FEI is again proposing no increase in delivery rates for 2019. This success is consistent with FEI's experience with its past two PBR plans (1998-2001 and 2004-2009).

7.2 Please confirm that all savings claimed in the referenced tables are annual savings. If unable to so confirm, please clarify.

Response:

Confirmed. The savings shown in the referenced tables are the annual savings achieved.

7.3 Please confirm/correct/clarify that totaling the figures presented in the referenced tables gives the following result: Total O&M spending of approximately $2.76M, Capital spending of approximately $17.1M, and ongoing annual Savings of approximately $6.56M.

Response:

Not confirmed.

FEI provides the following table listing the initiatives referenced in the tables in Appendix B-6 of the Application and summarizing the costs for implementation along with the anticipated O&M savings.

Name	Implementation			Anticipated O&M Savings			
	Year	Capital	O&M	2014/2015	2016	2017	2018+
Regionalization (Phase 1)	2014/15	$ 1.3	$ 0.9	$ 2.0	$ 1.0	$ 1.0	$ 1.0
Regionalization (Phase 2)	2016	$ 0.7	$ 0.8	$ -	$ 1.1	$ 1.1	$ 1.1
Project Blue Pencil	2014/15	< $0.3	$ -	$ 1.0	$ 1.0	$ 1.0	$ 1.0
Review of Technical and Infrastructure Provider	2014/15	$ 1.5	$ -	$ 1.8	$ 2.0	$ 2.0	$ 2.0
Online Service Application	2015/16/17	$ 1.9	$ 0.5	$ -	$ -	$ 0.05	$ 0.05
SAP Integration **	2017/18	$ 4.2	$ 0.3	Annual savings of $0.9 million starting 2019			
Gas Workforce Management ***	2017/18/19	$ 5.8	$ 1.1	$ -	$ -	$ -	$ 0.50
Common Trenching	2018/19	$ -	$ -	$ -	$ -	$ -	$ -
Total		$ 15.7	$ 3.6	$ 4.8	$ 5.1	$ 5.2	$ 5.7

** Costs and Savings are expressed in $ millions.*
*** SAP Integration costs and savings are shared between FEI and FBC.*
**** Gas Workforce Management savings are expected starting 2020.*
***** Common Trenching program under development with savings to be determined.*

The sum of the capital and O&M implementation costs in the table above total to approximately $19.3 million. The sum of the Anticipated O&M savings for each of the columns from 2014 to 2018+ total to approximately $20.7 million. Annual savings starting from 2019, including $0.9 million of SAP Integration savings, are expected to total to approximately $6.5 million per year.

In summary, the estimated O&M savings for these initiatives, both achieved and on an ongoing basis, provide an attractive payback relative to the costs of investments and have contributed to the overall O&M savings realized for the benefit of customers and FEI.

8.0 Reference: Exhibit B-1, pages B-16 to B-17 and page B-21

8.1 Using the Grand Forks Terminal Station CPCN Application as an example, please illustrate how FortisBC has increased the scope and number of stakeholders and rights holders consultations as compared to previous CPCN Applications.

Response:

Although consultation and engagement activities are determined on a project-by-project basis, FortisBC has experienced an increased expectation for public consultation, stakeholder consultation and engagement in past few years for all projects.

The Grand Forks Terminal Station (GFT) Reliability Project is a good example where a project has a capital cost below the CPCN threshold and all proposed work is being completed within the GFT substation property or within the established right of way, but still required consultation with the public, local residents, and Indigenous communities. The growing demand for consultation is also highlighted by the requests from the local community to continue engaging with FBC even after the project is complete. In response to requests and to allay concerns, FBC is committed to taking noise readings before and after the project to determine if noise levels have changed and to mitigate any noise-related concerns.

As mentioned in Section B1.4 of the Application, government requirements for stakeholder consultation and engagement with Indigenous communities are also becoming increasingly more involved, complex and extensive. For example, consultation for the GFT Reliability Project required FBC to engage with nine different Indigenous communities, a significant increase to what was done in the past as a result of overlapping claims.

The GFT Reliability Project also provides an example of increased engagement within the pole removal and resetting component of the project. In previous projects, engagement around excavation for pole resetting has been limited to areas on reserve, in areas adjacent to archeological sites, or within areas of high archeological potential. FBC's engagement for the GFT Reliability Project may require discussion or monitoring on a pole-by-pole basis within certain traditional territories. This level of engagement could impact FBC's regular O&M programs during the MRP term and is indicative of the overall trend of increasing engagement requirements.

9.0 Reference: Exhibit B-1, page B-30 (lines 11-21 and 26-32) and page B-32 (lines 4-10)

9.1 Does the fact that both FEI and FBC achieved O&M savings in excess of those associated with the productivity factors embedded in their respective formulae indicate that the productivity factors used in the current PBR plan were too conservative?

<u>Response:</u>

Please refer to the response to BCUC IR 1.6.3.1.

9.1.1 If not, please explain why not.

<u>Response:</u>

Please refer to the response to BCUC IR 1.6.3.1.

10.0 Reference: Exhibit B-1, page B-31, Table B2-2 and Exhibit B-1-1, Appendix B6, Tables A:B6-1 – B6.8

10.1 Is there any relationship between the information provided in Table B2-2 and the O&M savings referred to in Appendix B-6, Tables A:B6-1 – B6-8?

Response:

Table B2-2 compares FEI's actual O&M expenditures from 2014 to 2019 compared to formula O&M. Appendix B-6 Tables A:B6-1 – B6-8, as requested by the BCUC, provides details of FEI's major productivity initiatives that it has implemented and that have contributed to FEI's O&M savings achieved during the term of the Current PBR Plan, as observed in Table B2-2.

10.2 Please provide the actual and normalized values for ROE that FEI achieved in each year 2014-2018 inclusive and projected for 2019 (that underpins the projected 2019 O&M savings).

Response:

Please refer to the response to MoveUP 1.4.1 for he requested actual ROE values, including the 2019 projected ROE. Please note that FEI does not use normalized values when reporting its achieved ROE; however, the normalized figures have been provided below.

Year	FEI Normalized Pre-ESM
2014	9.50%
2015	9.52%
2016	9.65%
2017	9.25%
2018	8.99%
2019P	8.87%

10.3 Please confirm that the figures in the referenced table are in nominal dollars. If unable to confirm, please clarify.

Response:

Confirmed.

10.4 Based on Table B2-2, FEI appears to be saving $2.0M above formula in 2019. Are these savings all considered "temporary"?

Response:

The estimated 2019P $2.0 million O&M savings shown in Table B2-2 of the Application represents the expected savings when compared to the 2019 formula allowed funding. It is not possible for FEI to differentiate between those savings that were above the formula and those savings that were related to the productivity improvement factor (PIF) in establishing the 2019 Base O&M. However, the 2019 Base O&M for the MRP incorporates the permanent savings through the Adjusted 2018 Base O&M starting point. The 2019 Base O&M reflects permanent O&M savings of approximately $2.0 million that are expected to carry over to 2019.

11.0 Reference: Exhibit B-1, page B-31-B33

Appendix A3-1 and Appendix A3-2

11.1 Please provide a revised version of Appendix A3-1 including actual and forecast 2019 values for FortisBC Energy Inc.

Response:

Please refer to the response to BCUC IR 1.23.1 for the revised Appendix A3-1.

11.2 Please include additional rows in the response to part one showing the adjustments made for each year to derive the "Actual" (column a) values in Table B2-2.

Response:

The following is page 3 of the revised Appendix A3-1 attached to the response to BCUC IR 1.23.1 and includes the additional rows for the O&M tracked outside of formula (or flow-through items) to derive the 2014 to 2018 Actual and 2019 Projected Formula (column a) values in Table B2-2.

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**
33									
34	**Total Gross O&M Expenses [1]**			**257,788**	**260,034**	**259,459**	**259,631**	**271,551**	**279,148**
35									
36	**Less: O&M Tracked Outside of Formula**								
37	Pension/OPEB (O&M Portion)			(24,113)	(25,699)	(24,218)	(15,826)	(17,077)	(13,795)
38	Insurance			(4,948)	(6,237)	(5,519)	(5,283)	(5,203)	(5,473)
39	Biomethane O&M			(417)	(1,085)	(1,154)	(1,567)	(2,634)	(1,369)
40	NGT Stations			(484)	(1,009)	(1,205)	(1,508)	(2,099)	(2,339)
41	LNG O&M			(550)	(624)	(1,438)	(2,944)	(6,547)	(7,432)
42	MSP Reduction							789	829
43	Employer Health Tax								(2,630)
44	FEVI O&M (Pre-Amalgamation)			(35,592)					
45	FEW O&M (Pre-Amalgamation)			(664)					
46	**Total**			**(66,768)**	**(34,654)**	**(33,534)**	**(27,128)**	**(32,771)**	**(32,209)**
47									
48	**Total Actual Formula**			**191,019**	**225,380**	**225,925**	**232,503**	**238,780**	**246,939**

[1] Total Gross O&M Expenses as per line 27 is the starting row to use for showing the adjustments made for each year to derive the Actual column values in Table B2-2

11.3 Please include additional rows in the response to part one showing the determination of the inflation adjusted actual O&M as set out in Figure B2-1.

Response:

The following is page 3 of the revised Appendix A3-1 attached to the response to BCUC IR 1.23.1 and includes the determination of the inflation adjusted actual O&M, and on a per customer basis, as set out in Figure B2-1.

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**
33									
34	**Total Gross O&M Expenses [1]**		**264,923**	**257,788**	**260,034**	**259,459**	**259,631**	**271,551**	**279,148**
35									
36	**Inflation 2019 Dollars**		112.3%	110.3%	108.8%	107.3%	104.9%	102.1%	100.0%
37									
38	**Inflation Adjusted Actual O&M**		**297,466**	**284,347**	**282,937**	**278,387**	**272,261**	**277,192**	**279,148**
39									
40	**Average number of customers**		945,880	959,196	968,766	983,807	997,380	1,016,353	1,024,962
41									
42	**Total O&M per Customer (Inflation Adjusted)**		**$ 314**	**$ 296**	**$ 292**	**$ 283**	**$ 273**	**$ 273**	**$ 272**

[1] Total Gross O&M Expenses as per line 27

11.4 Please include additional rows in the response to part one setting out the number of customers for each year and the derivation of the Total O&M per Customer (Inflation Adjusted) per Figure B2-1.

Response:

Please refer to the response to BCOAPO IR 1.11.3.

11.5 Please provide a revised version of Appendix A3-2 including actual and forecast 2019 values for FortisBC Inc.

Response:

Please refer to the response to BCUC IR 1.23.1 for the revised Appendix A3-2.

11.6 Please include additional rows in the response to part five showing the adjustments made for each year to derive the "Actual" (column a) values in Table B2-3.

Response:

The following is page 2 of the revised Appendix A3-2 attached to the response to BCUC IR 1.23.1 and includes the additional rows for the O&M tracked outside of formula (or flow-through items) to derive the 2014 to 2018 Actual and 2019 Projected Formula (column a) values in Table B2-3.

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***
39									
40	Add (Less):	O&M Tracked Outside of Formula							
41		Pension/OPEB (O&M Portion)		$ (5,904)	$ (3,925)	$ (3,391)	$ (3,267)	$ (2,659)	$ (1,692)
42		Insurance		$ (1,341)	$ (1,334)	$ (1,306)	$ (1,268)	$ (1,245)	$ (1,283)
43		Advanced Metering Infrastructure Costs/Savings		$ (431)	$ (272)	$ 1,391	$ 1,246	$ 1,203	$ 1,161
44		Mandatory Reliability Standards Audit			$ (375)	$ (464)	$ (53)		
45		Mandatory Reliability Standards Incremental O&M						$ (1,024)	$ (940)
46		Upper Bonnington Unit 3 Annual Inspection					$ 40	$ 40	$ 42
47		MSP Reduction						$ 177	$ 168
48		Employer Health Tax							$ (576)
49									
50		***Total***		***(7,676)***	***(5,905)***	***(3,770)***	***(3,302)***	***(3,508)***	***(3,120)***
51									
52		***Actual Formula O&M***		***52,046***	***51,880***	***51,839***	***52,520***	***53,847***	***55,581***

11.7 Please include additional rows in the response to part one showing the determination of the inflation adjusted actual O&M as set out in Figure B2-2.

Response:

The following is page 2 of the revised Appendix A3-2 and includes the determination of the inflation adjusted actual O&M, and on a per customer basis, as set out in Figure B2-2.

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***
39									
40		Inflation 2019 Dollars	112.3%	110.3%	108.8%	107.3%	104.9%	102.1%	100.0%
41									
42		***Inflation Adjusted Actual O&M***	***63,661***	***65,876***	***62,874***	***59,666***	***58,537***	***58,547***	***58,701***
43									
44		Average number of Customers	128,557	129,525	131,016	132,480	134,246	137,300	138,649
45									
46		***Total O&M per Customer (Inflation Adjusted)***	***$ 495***	***$ 509***	***$ 480***	***$ 450***	***$ 436***	***$ 426*** [1]	***$ 423***

[1] Total O&M per Customer (Inflation Adjusted) of $426 for 2018 slightly changed from the Total O&M per Customer of $429 as depicted in Figure B2-2 as the 2018 O&M Actual used in the graph was a preliminary number

11.8 Please include additional rows in the response to part four setting out the number of customers for each year and the derivation of the Total O&M per Customer (Inflation Adjusted) per Figure B2-2.

<u>Response:</u>

Please refer to the response to BCOAPO IR 1.11.7.

12.0 Reference: Exhibit B-1, pages B-34 and B-35, Table B2-4 and Figure B2-3, and Exhibit B1-1, Appendix B8-1, pages 2-7

12.1 FEI attributes the large variances in growth capital over the PBR period to unanticipated developments (change in customer mix, increased SLAs on VI) going into the PBR and to the use of historical costs for inputs along with the 50% formulaic reduction to the growth factor. Is FEI convinced that errors in customer forecast numbers were not a material driver of the growth capital variance?

Response:

When determining the formulaic Growth capital each year of the Current PBR Plan, FEI did not use a forecast of customer additions, so it could not be a material driver of variances. Order G-138-14 determined that FEI would use a lagging actual growth factor in its formula to determine Growth capital. As such, variances in funding Growth capital due to forecast are actually variances from using a lagging growth term. Please refer to the response to CEC IR 1.11.1 for a discussion of the Growth capital variance including the lagging growth factor. FEI explains in Section B2.3.2.1.1 of the Application that the current Growth capital formula provides funding that is not as well correlated to customer attachments as actual costs.

12.2 Please provide a breakdown by rate class of customer numbers forecast and actual customers for each year 2014-2018 inclusive.

Response:

FEI has provided the response as it relates to total customers.

Actual customers and forecast customers are shown for Rate Schedules 1, 2, 3 and 23 in the table below[2]. FEI does not forecast customers for any of the industrial rate schedules. As a result, only actual customers are shown in the table below for Rate Schedules 4 through 27 and Natural Gas for Transportation (NGT).

2 Please note that the table reflects final year end customer counts.

Customers	**2014**	**2015**	**2016**	**2017**	**2018**
Rate Schedule 1					
Forecast	866,852	883,371	892,830	909,727	916,365
Actual	873,661	886,169	897,528	910,885	930,142
Rate Schedule 2					
Forecast	81,923	84,651	85,667	87,712	88,494
Actual	83,625	85,076	86,074	86,973	88,244
Rate Schedule 3					
Forecast	5,147	5,117	5,035	5,354	5,223
Actual	5,169	5,301	5,189	5,441	6,028
Rate Schedule 23					
Forecast	1,634	1,552	1,670	1,760	1,934
Actual	1,522	1,724	1,803	1,712	1,648
Rate Schedule 4	2	2	1	4	2
Rate Schedule 5	265	243	238	260	311
Rate Schedule 6	12	13	7	6	6
Rate Schedule 7	3	6	6	11	16
Rate Schedule 22	44	47	49	48	51
Rate Schedule 25	548	555	545	532	529
Rate Schedule 27	101	108	107	113	107
NGT	18	31	42	56	44

12.3 Please provide a revised Table 2-4 assuming the 50% growth reduction factor had not been in place in the current PBR.

<u>Response:</u>

Please refer to the response to BCUC IR 1.8.1, Table 2.

13.0 Reference: Exhibit B-1-1, Appendix B8-1, pages 7-9, Table A:B8-1-4

13.1 Does FEI agree that, in general, variances from forecast in sustainment and other capital expenditures would be expected to be smaller that growth capital variances since, among other things, sustainment capital expenditures generally relate to capital that is already in rate base and for which the condition is well known?

Response:

While FEI agrees that the scope of work for Sustainment and Other capital is better known than it is for Growth capital, it would be an oversimplification of the scope and cost drivers to state that this is the only cause of variances from forecast. FEI also notes that the amount of capital in rate base is not relevant to the level of variances from forecast for capital expenditures.

Generally speaking, Growth capital has a higher degree of scope uncertainty than does Sustainment and Other capital. This is because the majority of expenditures in Growth capital are initiated by customers and are often sensitive to customer needs. Customer demand is heavily influenced by economic conditions and the housing market, neither of which are in the control of FEI.

However, external factors such as customer additions and third party activity also create a degree of uncertainty and variability in Sustainment capital forecasts through station and pipeline reinforcements that are required to support load growth and forced relocation of assets to accommodate other infrastructure projects. Expenditures in Sustainment and Other capital also tend to be more complex, comprised of larger individual projects, and more reliant on technological changes that are occurring at an accelerated rate, driving the need for more frequent replacement or upgrade of technology assets.

Finally, Sustainment capital projects are often located in congested urban settings that present a higher level of execution risk than a Growth capital project to extend service to a new development. These are just of few of the factors and influences that FEI has to consider within its capital portfolio to forecast the scope and magnitude of expenditures.

14.0 Reference: Exhibit B-1, page B-36, Table B2-5

14.1 Please provide a revised version of the referenced table that includes pension and OPEB.

<u>Response:</u>

A revised version of Table B2-5 which includes pension and OPEB is provided below. To include pension and OPEB, FortisBC has used the approved pension and OPEB costs that were allocated to Sustainment and Other capital in each year's Annual Reviews. The annual variances between Actual and Formula Sustainment and Other capital remain the same as variances between forecast and actual pension and OPEB costs are captured in a deferral account.

Year	Sustainment & Other Capital			
	Actual	Formula	Variance	% Variance
2014	103.226	101.401	- 1.825	-1.8%
2015	111.029	114.127	3.098	2.7%
2016	117.681	115.093	- 2.588	-2.2%
2017	141.403	115.091	- 26.312	-22.9%
2018	152.663	116.930	- 35.733	-30.6%
2019P	147.020	119.777	- 27.243	-22.7%
Total	772.961	682.419	- 90.542	-13.3%

15.0 Reference: Exhibit B-1, page B-39, Tables B2-7 and B2-8

15.1 Please explain how the average annual cost for the PBR proceedings in the referenced tables was calculated.

Response:

The average annual cost for PBR proceedings is the total of the 2014 PBR proceeding and the five Annual Review proceedings, divided by the total of six proceedings. As identified in footnotes 57 and 58 of the Application, the external consulting costs of the depreciation studies filed with the Annual Reviews for 2016 Rates were excluded because the depreciation studies are not associated with the Current PBR Plan itself. The calculations are provided in the following table.

FEI and FBC PBR Proceedings Costs ($000s)

	2014 PBR Plan Application	Annual Reviews for 2015-2019 Rates	Average Annual Review Cost	Total Regulatory Costs	Average Annual Cost
	(a)	(b)	(c)=(b)/5	(d)=(a)+(b)	(e)=(d)/6
FEI	$ 1,831	$ 660	$ 132	$ 2,491	$ 415
FBC	$ 1,541	$ 623	$ 125	$ 2,162	$ 360

15.2 In FEI's view, are the average annual costs of a two-year cost of service proceeding similar to the average annual costs of a one-year cost of service proceeding?

Response:

No. FortisBC believes that multi-year cost of service proceedings are more efficient than single-year cost of service proceedings and that the costs of a two-year proceeding would likely be similar to a those of a one-year proceeding.

16.0 Reference: Exhibit B-1, page B-48 (lines 1-8)

16.1 Please indicate the strategic long-term initiatives FBC has underway that are currently treated outside the PBR framework and indicate how and why they are receiving this treatment.

Response:

Please refer to the response to BCUC IR 1.13.7.

16.2 With respect to line 7, please confirm if the reference to C3.3.7 is correct.

Response:

The stated reference was incorrect and should have been to Section C8.3 regarding Targeted Incentives.

17.0 Reference: Exhibit B-1, Page B-53, Figure B2-6

17.1 Please provide a revised version of Figure B2-6 where for each year and metric the Figure sets out FEI's ranking relative to the total number of utilities in the sample (e.g. 3/14 would indicate that that FBC had the third best result out of 14 utilities – FEI plus its 13 member peer group).

Response:

The following response has been prepared by Concentric.

Please see the table below, which provides the requested information. Please note that Figure B2-6 presents the percentage difference between FEI's result and the Canadian peer group's median (including FEI) result, per metric, per year. As such, those results were relative to the Canadian peer group only. In addition, Figure B2-6 reflects only those companies within the Canadian peer group for which data was available. (Note: in each case, 1 represents the best performance for this metric for the companies providing data).

FEI Metric and Rank	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	1/5	1/5	1/5	1/5	1/5	2/5
Distribution O&M + Total A&G per TJ	3/5	2/5	3/5	3/5	2/5	3/5
Distribution O&M + Total A&G per Employee	1/4	1/5	1/5	1/5	1/5	1/5
Distribution O&M + Total A&G per km of Mains	3/4	2/5	2/5	2/5	2/5	2/5
Distribution Net Plant per Customer	4/6	4/6	4/6	4/6	4/6	3/6
Distribution Net Plant per Employee	3/5	4/6	4/6	4/6	4/6	3/6
Distribution Net Plant per Employee	3/5	3/6	3/6	3/6	3/6	3/6
Administrative and General Expense per Customer	2/5	2/5	2/5	2/5	2/5	2/5
Administrative and General Expense per TJ	3/5	3/5	3/5	3/5	3/5	3/5
Customer Care Expense per Customer	2/4	2/4	2/4	2/4	2/4	2/4
Customer Care Expense per TJ	3/4	3/4	3/4	3/4	3/4	3/4
Interest Expense per Customer	4/6	5/6	5/6	5/6	5/6	4/6
Emergency Response Time (within 1 hr)	2/5	2/6	4/6	3/6	3/6	3/6
Telephone Service Factor - Emergency	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non-Emergency	3/3	4/4	3/4	4/4	4/4	4/4
First Contact Resolution	NA	NA	NA	NA	NA	NA
Telephone Abandon Rate	2/5	1/5	1/5	2/5	3/5	2/5
DSM Expenditures (with incentives) per Customer	2/4	2/4	2/4	2/4	3/4	3/4
DSM Expenditures (without incentives) per Customer	1/4	2/4	2/4	2/4	3/4	3/4
DSM Expenditures (incentives only) per Customer	2/4	2/4	2/4	2/4	2/4	3/4

FEI Metric and Rank	2012	2013	2014	2015	2016	2017
Total Emissions tonnes CO2e per Customer	3/5	3/5	3/5	2/5	2/5	NA
Total Emissions tonnes CO2e per TJ	4/5	4/5	4/5	3/5	3/5	NA

18.0 Reference: Exhibit B-1, page B-56 (Figure B2-7)

18.1 Please provide a revised version of Figure B2-7 where for each year and metric the Figure sets out FBC's ranking relative to the total number of utilities in the sample (e.g. 3/14 would indicate that that FBC had the third best result out of 14 utilities).

<u>Response:</u>

The following response has been prepared by Concentric.

Please see the table below, which provides the requested information. Please note that Figure B2-7 presents the percentage difference between FBC's result and the Canadian peer group's median (including FBC) result, per metric, per year. As such, those results were relative to the Canadian peer group only. In addition, Figure B2-7 reflects only those companies within the Canadian peer group for which data was available. (Note: in each case, 1 represents the best performance for this metric for the companies providing data).

FBC Metric and Rank	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	4/8	2/8	4/9	3/9	4/9	3/8
Distribution O&M + Total A&G per MWh	4/9	3/9	3/9	3/9	3/9	2/9
Distribution O&M + Total A&G per Employee	1/9	1/9	1/9	1/9	1/9	1/9
Distribution O&M + Total A&G per km Distribution Line	2/7	2/7	3/7	3/7	3/7	3/7
Distribution Net Plant per Customer	9/10	9/10	9/10	9/10	9/10	8/9
Distribution Net Plant per Employee	7/10	9/10	9/10	8/10	7/10	5/9
Distribution Net Plant per km Distribution Line	7/8	7/8	7/8	7/8	6/8	5/7
Administrative and General Expense per Customer	4/8	4/8	4/9	4/9	5/9	5/8
Administrative and General Expense per MWh	4/8	3/8	5/9	4/9	4/9	4/8
Customer Care Expense per Customer	4/4	4/4	5/5	5/5	5/5	4/4
Customer Care Expense per MWh	4/4	4/4	5/5	5/5	5/5	4/4
Interest Expense per Customer	9/9	9/9	8/9	8/9	7/9	7/9
Emergency Response Time (within 2 hrs)	2/4	2/4	1/4	1/4	2/4	2/4
SAIDI	4/8	5/9	5/9	4/9	4/9	7/9
SAIFI	4/8	4/9	5/9	6/10	4/10	8/10
Generator Forced Outage Rate	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non Emergency	4/5	5/5	5/5	4/5	4/5	3/5
First Contact Resolution	NA	5/6	5/6	5/6	6/7	7/8
Telephone Abandon Rate	3/6	3/7	7/7	4/7	5/7	4/8
DSM Expenditures (with incentives) per Customer	5/5	5/5	3/5	3/5	6/6	5/6

FBC Metric and Rank	2012	2013	2014	2015	2016	2017
DSM Expenditures (without incentives) per Customer	3/4	3/4	2/4	3/4	4/5	5/5
DSM Expenditures (incentives only) per Customer	4/4	3/4	3/4	3/4	4/5	4/5

19.0 Reference: Exhibit B-1, page B-69, lines 3-5

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

19.1.1 Does FEI draw any inferences from the regulatory preferences of investor-owned utilities versus the regulatory preferences of municipal utilities and co-ops?

Response:

FortisBC does not draw any particular inferences from differences between investor-owned utilities and municipal/co-op utilities with regard to future regulatory models to be employed in their regulation. As noted in the paragraph preceding the selected quote in the question from page B-69 of the Application, the information presented was based on a survey of utility industry professionals about their expectations regarding the form of regulation they expected to face in the future. The lower expectations among municipal utilities and co-ops of future regulation by PBR or mixed cost-of-service/PBR may be simply a function of lower expectations among these utilities that the legal, regulatory or policy framework governing their regulatory model will change materially in the future from what it is today.

19.1.2 Is FEI aware of any studies comparing the rates at investor-owned utilities versus the rates at comparable municipal utilities and co-ops? If so, please provide details.

Response:

Every year, Hydro Quebec publishes a rate comparison document titled "Comparison of Electricity Prices in Major North American Cities". As can be seen in the table below, this study includes several municipal utilities in both Canada and the U.S:

Municipal Utility Name	Owner
ENMAX	City of Calgary
EPCOR	City of Edmonton
Toronto Hydro	City of Toronto

Municipal Utility Name	Owner
Hydro Ottawa	City of Ottawa
Nashville Electric Service	City of Nashville
Seattle City Light	City of Seattle

The latest version of this study can be retrieved from the link below:

http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf

20.0 Reference: Exhibit B-1, pages B-70 (Table B2-9) and B-72 (lines 19-25)

Exhibit B-1, Appendix C4-2

20.1 Table B2-9 sets out the X factor used in each of the MRPs summarized. Appendix C4-2 (page 11) provides a breakdown of the X factor established by the AUC as between the TFP factor and the stretch factor. Similarly, at page 31 a discussion is provided regarding the Regie's derivation of the X factor HQD. However, a similar discussion is not provided regarding the determination/breakdown of the X factor used for Ontario Electric Distributors (Section 3). Please explain the basis for the X factors as applied to Ontario electric distributors.

Response:

The X-Factor value for Ontario's electric distributors is based on a fixed base productivity growth factor of zero percent (last set in 2013) and a variable stretch factor (between 0 percent to 0.6 percent) that is set based on the results of the annual total cost benchmarking studies conducted by the OEB.

The base productivity growth factor was set based on OEB's judgement at zero percent

In 2013, as part of the fourth generation incentive rate-setting mechanism proceeding (EB-2010-0379), the OEB issued a report titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors". This report provides the OEB's final determination on its policies and approaches to the distributor rate adjustment parameters including the base productivity factor for the 2014-2018 rate period (later extended to 2019).

Unlike the TFP studies in other proceedings where the experts relied on U.S. data for their models, the OEB's consultant (PEG) relied on the data from Ontario's electric utilities. (The OEB agreed with PEG to remove the data related to outliers, Hydro One and Toronto Hydro, from calculations since they materially impacted the end results). PEG's final recommendations to the OEB were set out in its report released in November of 2013, entitled "Empirical Research in Support of Incentive Rate Setting in Ontario".

The PEG study indicated that the TFP results changed dramatically when the analysis was updated to include 2012 data (from 0.19 percent for 2002-20011 to -0.33 percent for 2002-2012). Such a dramatic change caused PEG to question the reasonableness of the data included in the analysis. Because of these data-related concerns PEG decide to distance itself from the calculated negative TFP numbers and use its judgement to recommend a zero percent base productivity factor. The OEB agreed with PEG's recommendation:

> **The Board has determined that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero.** The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity trend in the sector over the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve …
>
> In addition, the Board agrees with the analysis by PEG (supported by the OM&A analysis by Board Staff) that the 2012 TFP results appear anomalous and therefore may not be a reliable indicator of the future productivity trend. As a consequence, the Board has determined that, at this time, where the estimate of achieved long-run Industry TFP is negative, the productivity factor used in the rate-adjustment formula to set rates will be set to zero.

OEB's negative TFP numbers and the associated decision to set the base productivity at zero percent were discussed in the BCUC's 2014 PBR Decision. In the 2014 PBR Decision, the BCUC panel determined that considering the data issues identified by the OEB's report, the TFP numbers from this proceeding should not be given any weight which is the reason, as mentioned in the question, the X-Factor study for Ontario's electric distributors was not discussed in more detail in the Appendix C4-2[3]:

> With regard to the applicability of the fourth generation study to electric utility MFP trends, the Panel is concerned that the results may be skewed by the three issues outlined in the PEG report, in particular the issue of clearing the deferral accounts. Accordingly, in the absence of further evidence, the Panel is not prepared to give any weight to this study.

Variable efficiency factors (between 0.0 percent to 0.6 percent) added to the base productivity factor

In its decision, the OEB determined that distributors shall be assigned to one of the five cohorts based on their cost evaluation ranking. The efficiency factor for each cohort is provided in the table below:

Group	Actual costs are 10% to 25% below predicted costs	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00 %
II	Actual costs are 10% to 25% below predicted costs	0.15 %
III	Actual costs are within +/-10% of predicted costs	0.30 %
IV	Actual costs are 10% to 25% above predicted costs	0.45 %

[3] BCUC 2014 PBR decision, page 79.

Group	Actual costs are 10% to 25% below predicted costs	Stretch Factor
V	Actual costs are 25% or more above predicted costs	0.60 %

The stretch factor values are set based on OEB's judgement. The stretch factor assignments on the other hand are based on the results of a statistical cost benchmarking study designed to make inferences on individual distributors' cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distributors that had actual cost that was lower than that predicted by the model were assigned lower stretch factors than those that did not. These total cost benchmarking studies are updated each year and the distributors are assigned a stretch factor based on the results of the study in that year. As such, the stretch factor for each utility can change from one year to the other depending on the benchmarking study results. To the best of FortisBC's knowledge, the last updated study was issued in August of 2018[4].

[4] https://www.oeb.ca/sites/default/files/PEG-benchmarking-report-20180823-revised.pdf.

21.0 Reference: Exhibit B-1, page B-80 (lines 10-23) and page B-81 (lines 1-2)

21.1 Based on the discussion in this paragraph, will "targeted incentives" only be used for initiatives that results in downward pressure on rates (i.e., a reduction in rates) through the promotion of load growth?

<u>Response:</u>

No, targeted incentives are not restricted to initiatives that result in downward pressure on rates although that is expected to be an outcome of some of the initiatives. Rather, they are focussed on achieving outcomes that create positive value for end users, ratepayers and society. As an example, increasing customer engagement through digital communication channel adoption is not expected to place downward pressure on rates by lower costs or growing load in the near term. Rather, it is intended to benefit customers by providing convenient access to services and information, better meeting their expectation to engage with FortisBC on their own terms. However, over the longer-term, increasing customer engagement will help attract and retain customers contributing to maintaining system load and helping to manage rates for the benefit of all customers.

21.1.1 If not, please explain how the incented initiatives can be viewed as being to the "benefit of ratepayers" per page B-81.

<u>Response:</u>

Please refer to the responses to BCOAPO IR 1.21.1 and BCUC IR 1.96.7.

22.0 Reference: Exhibit B-1, page C-8, lines 10-25

FortisBC discusses its true up mechanism for growth factors.

22.1 Please confirm that a true up of forecast costs or revenues to actual results transfers risk from the shareholder to the customer.

Response:

Not confirmed. The Companies are proposing a true-up for the forecast of gross customer additions and average number of customers, but are not proposing a true-up of the unit cost per customer for either Growth capital or O&M. This way customers and the utility are held whole for forecast variances related to the number of customers. Variances in unit cost will fall to earnings and be shared through the ESM.

22.1.1 If confirmed, please fully explain why the introduction of a true up mechanism should not result in a reduction in the allowed return on equity or equity thickness to adjust for a change in risk allocation between shareholders and customers.

Response:

Please refer to the response to BCOAPO IR 1.22.1.

22.1.2 If not confirmed, please fully explain.

Response:

Please refer to the response to BCOAPO IR 1.22.1.

23.0 Reference: Exhibit B-1, page C-9, lines 3-11

FortisBC indicates that there is a high correlation between new attachments and capital or O&M. In stating that there is a high correlation coefficient, FortisBC implies that it has done some sort of linear regression of the relationship between costs and new attachments.

23.1 Please provide the calculation of the correlation coefficients in Excel format with formulae and links intact. In the response please provide the actual regression analysis and resulting slope and intercept.

Response:

The correlation coefficient, slope and intercept for the requested information is provided in the following table and the spreadsheet in Attachment 23.1. The slope of the O&M lines are 0.332 for FEI and 0.377 for FBC. This means that, according to the regression equation, FEI added $332 (0.332 x $1,000 because the dollar units are in $000s) for each additional FEI customer and FBC added $377 for each additional FBC customer.

		2014	2015	2016	2017	2018	2019P	Correlation	Slope	Intercept
FEI	*New attachments*	13,583	16,213	17,261	20,825	22,439	18,540	0.95	5.870	(52,628)
	Actual Growth Capital ($000)	$ 24,230	$ 45,780	$ 47,500	$ 59,540	$ 82,880	$ 63,330			
FEI	*Average Number of Customers*	959,196	968,766	983,807	997,380	1,016,353	1,024,962	0.95	0.332	(96,883)
	Actual Formula O&M ($000)	$ 223,970	$ 225,380	$ 225,930	$ 232,500	$ 238,690	$ 246,940			
FBC	*Average Number of Customers*	129,525	131,016	132,480	134,246	137,300	138,649	0.90	0.377	2,537
	Actual Formula O&M ($000)	$ 52,046	$ 51,880	$ 51,839	$ 52,520	$ 53,839	$ 55,581			

Keeping in mind that the values are nearly equal, for FEI the average costs added (represented by the slope from the 2014-2019 regression above) are higher than the base unit cost per customer, while the opposite is true for FBC. This determination can be made by dividing the slope by the 2019 Base O&M unit cost per customer of $250 for FEI and $416 for FBC.

- For FEI, the regression analysis suggests that FEI would require an O&M increase of $332 for each new customer, whereas FEI is requesting $250 per customer (greater than a 1 to 1 relationship).

- For FBC, the regression analysis suggests that FBC would experience an O&M increase of $377 for each new customer, whereas FBC is requesting $416 (at approximately 90 percent, slightly less than a 1 to 1 relationship).

While the intercepts can be construed as representing fixed costs at the point where the number of customers equals zero, the negative amounts for both Growth capital and O&M for FEI and the small intercept for FBC are irrelevant in this case. First, it is not possible to have negative costs at zero customers, and second, a regression analysis is most useful over the range that the regression was performed. This means that the regression results will become less useful for extrapolations far outside the range of the original data[5].

Overall, the results of these analyses provide support, based on actual data from the 2014-2019 PBR period, for growth factors in the MRP formulas to recognize the full customer additions and for discontinuation of the 50 percent factor applied to growth in the 2014-2019 PBR.

Note that the Companies have been under formula for Growth capital and O&M since 2014 and therefore, have provided data for the years 2014 through to 2019, where 2019 is projected.

23.2 Please provide all supporting data used to determine the correlation coefficients. In the response, please provide actual new attachments, formula O&M and each component of formula capital for each of the last 10 years.

Response:

Please refer to the response to BCOAPO IR 1.23.1.

[5] For FEI, the New Attachments range is 13,583 to 22,439 and the Average Number of Customers range is 959,196 to 1,024,962. For FEI, the Average Number of Customers range is 129,525 to 138,649.

24.0 Reference: Exhibit B-1, page C-9, line 25 – page C-10, line 15

FortisBC discusses the "persistent underfunding of formula capital amounts." In its principle 2, FBC states:

> The MRP must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

24.1 Please confirm that formula O&M did not experience a similar under-funding because formula O&M included a 50 percent reduction in the Growth Factor. If not confirmed, please fully explain.

Response:

FEI and FBC were both successful in managing overall O&M expenditures during the term of the Current PBR Plans below that allowed under the O&M formula. However, absent the Companies' success in achieving efficiencies that have contributed to reducing O&M costs, the Companies could have been underfunded similarly to FEI's Growth capital.

Due to the steady and relatively small annual percentage of change in average number of customers used as the Growth factor for the O&M formulas, compared to the more volatile and relatively significant annual percentage of change in the growth factor used for Growth capital formula, the impact of the 50 percent reduction on the O&M formula was overall more manageable than the impact on the capital formulas.

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.

24.2 Please fully discuss whether a reasonable opportunity to recover prudently incurred costs should be applied to each of formula O&M and each component of formula Capital separately or should be applied to each of the Fortis utilities in aggregate.

Response:

FortisBC interprets both views as being one in the same and consistent with the requirement that the rate-setting model (regardless of the type) must provide the utility with a reasonable opportunity to recover its prudently incurred costs and a fair return. The reference to "reasonable opportunity to recover prudently incurred costs" applies equally to O&M and capital as both are necessary for the Companies to provide safe and reliable service to its customers.

24.3 For each of the years of the prior MRP for each of FEI and FBC, please provide:

24.3.1 Formula Revenue Requirement with each component of Revenue Requirement identified.

Response:

FEI interprets the request for "formula revenue requirement" as "approved revenue requirement" and provides the data below accordingly.

FEI ($000s)	2014		2015		2016		2017		2018		2019	
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual
Cost of Energy	$ 496,151	$ 581,947	$ 640,486	$ 498,695	$ 477,714	$ 348,062	$ 295,403	$ 437,890	$ 424,275	$ 360,863	$ 369,282	N/A
O&M	200,973	193,644	237,424	226,568	238,067	225,769	236,050	225,786	241,481	235,878	246,088	N/A
Depreciation & Amortization	154,280	154,624	189,989	189,286	199,490	197,916	199,526	197,700	222,212	208,086	230,699	N/A
Property Taxes	48,797	47,554	61,015	60,801	63,036	63,265	67,450	63,281	67,157	62,596	67,559	N/A
Other Revenue	(24,567)	(25,628)	(41,226)	(41,136)	(41,852)	(42,152)	(42,958)	(42,922)	(46,048)	(45,666)	(44,893)	N/A
2017/2018 Revenue Surplus	-	-	-	-	-	-	32,012	32,012	5,398	5,398	-	N/A
Flowthrough	-	3,073	-	4,264	-	11,218	-	7,750	-	28,417	-	N/A
Income Taxes	41,517	41,856	49,002	52,834	46,173	52,501	35,651	40,654	50,137	56,649	52,972	N/A
Earned Return	202,928	210,555	256,532	266,804	254,909	265,216	246,984	255,658	281,696	287,920	291,732	N/A
Revenue	$ 1,120,079	$ 1,207,625	$ 1,393,222	$ 1,258,116	$ 1,237,537	$ 1,121,795	$ 1,070,118	$ 1,217,809	$ 1,246,308	$ 1,200,141	$ 1,213,439	N/A
ROE (actual is after-sharing)	8.75%	9.20%	8.75%	9.19%	8.75%	9.28%	8.75%	9.04%	8.75%	8.93%	8.75%	N/A

FBC ($000s)	2014		2015		2016		2017		2018		2019	
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual
Cost of Energy	$ 102,315	$ 101,069	$ 132,367	$ 125,222	$ 148,962	$ 138,166	$ 151,472	$ 148,654	$ 148,450	$ 139,629	$ 160,765	N/A
O&M	51,604	50,616	50,227	48,921	48,432	47,063	48,917	47,189	49,802	48,566	50,321	N/A
Depreciation & Amortization	59,146	59,146	52,833	52,971	51,694	51,240	55,657	55,618	52,667	53,052	48,473	N/A
Property Taxes	15,903	14,792	15,331	14,798	15,407	15,493	16,052	15,723	16,684	16,147	16,713	N/A
Other Revenue	(7,582)	(8,943)	(8,272)	(9,045)	(8,177)	(8,630)	(8,056)	(9,724)	(8,416)	(10,139)	(9,268)	N/A
Revenue (Deficiency)/Surplus	21,934	21,934	-	-	-	-	-	-	(896)	(896)	5,633	N/A
Flowthrough	(17,798)	(18,296)	-	(2,412)	-	(2,191)	-	8,470	-	11,656	-	N/A
Income Taxes	11,138	11,920	6,684	6,829	8,310	7,186	10,849	12,201	9,633	12,545	7,827	N/A
Earned Return	86,745	85,091	85,361	86,090	85,965	86,860	87,237	86,724	88,416	89,322	90,071	N/A
Revenue	$ 323,403	$ 317,330	$ 334,531	$ 323,375	$ 350,593	$ 335,186	$ 362,128	$ 364,854	$ 356,340	$ 359,882	$ 370,534	N/A
ROE (actual is after-sharing)	9.15%	9.22%	9.15%	9.26%	9.15%	9.38%	9.15%	9.31%	9.15%	9.29%	9.15%	N/A

24.3.2 Actual Revenue Requirement with each component of Revenue Requirement identified.

Response:

Please refer to the response to BCOAPO IR 1.24.3.1.

24.3.3 Actual utility return on equity.

Response:

Please refer to the response to BCOAPO IR 1.24.3.1.

24.3.4 Authorized return on equity.

Response:

Please refer to the response to BCOAPO IR 1.24.3.1.

24.4 Please fully discuss whether, under an MRP, the utility should trade off capital and O&M to maximize efficiency. In the response please fully discuss why or why not.

Response:

Yes, companies may trade-off capital and O&M to maximize efficiency. A utility for instance may invest in new equipment or software that can automate certain repetitive processes and reduce the associated O&M expenditures. In the case of replacing O&M with capital solutions, the customers will benefit from lower overall cost and the utility will also earn the authorized return on and of its investment.

Alternatively, a utility may be able to replace or defer significant capital expenditures with innovative O&M-intensive solutions. In the case of replacing capital expenditure with O&M solutions, customers will benefit from the reduced costs, but the utility will lose rate base growth potential and associated earnings. Recognizing this disincentive and to promote innovation, many regulators have approved alternative incentive mechanisms to remove the innovation disincentive inherent in traditional cost of service regulation. For instance, as explained in response to BCUC IR 1.15.5, regulators have approved new accounting treatments to remove the incentive disparity between adopting on-premise versus cloud-based computing systems.

The alternative incentives for non-wire and non-pipe solutions are another example of levelling the playing field between capital and O&M expenditures. For instance, as explained in Section 3.1.5 of the Appendix C4-3, the New York regulator approved several unique financial incentives to ensure that the ConEdison is indifferent to investments in Distributed Energy Resources and traditional infrastructure investments with higher rate base growth potential.

The decision to trade-off between O&M and capital expenditures is not limited to financial considerations. Factors such as corporate culture and organizational agility and the ability to forecast future needs may also be considered.

24.4.1 If yes, please explain how this might be done.

<u>Response:</u>

Please refer to response to BCUC IR 1.24.4.

25.0 Reference: Exhibit B-1, page C-10, line 20

On line 20, FortisBC indicates it is planning on using Gross Customer Additions.

25.1 Please fully explain Gross Customer Additions and explain why Gross Customer Additions is the preferred metric.

<u>Response:</u>

Gross customer additions measures the number of new customers attaching to FEI's natural gas system, through the process of FEI installing a service line and attaching a meter for that customer. In some situations, where the customer is further away from an existing main, a main extension is also required. Accordingly, gross customer additions is a direct measure of the volume of activity required for Growth capital expenditures (i.e., the installation of service lines, mains and meters) and is, therefore, the appropriate metric for FEI's Growth capital.

Gross customer additions is different from both service line additions (SLA) and net customer additions. SLA captures the number of risers that are installed regardless of the number of customers that will be serviced by each riser. In multi-family developments, a higher number of customers are serviced by one riser and therefore the cost of installation would be higher. For this reason, using SLA as a metric creates greater variations in costs if the proportion of multi-family versus single family developments changes. Net customer additions is calculated by taking gross customer additions as described above, deducting for the attrition of customers (i.e. move-ins and abandonments), and then accounting for new customers by way of move-ins. As such, net customer additions is not a good measure for customer Growth capital as it is impacted by attrition, which does not drive Growth capital.

25.2 Please provide the Gross and Net Customer Additions for each year of the prior MRP.

<u>Response:</u>

Please see the table below for actual gross customer additions and net customer additions for each year of the Current PBR (i.e., prior to the MRP):

	2014	2015	2016	2017	2018
Net Customer Additions	11,676	14,305	12,314	14,452	21,087
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439

Note: Gross Customer additions includes company use and Fort Nelson customers.

26.0 Reference: Exhibit B-1, page C-12, lines 16-29

FortisBC discusses the proposed ECM model, which is based on achieved ROE for the last two years of the multiyear rate plan.

26.1 Please fully explain how the FortisBC proposal for an ECM **excludes** the impact of efficiencies that were implemented in years 1-3 of the multiyear rate plan and have simply carried over to the last two years of the plan.

Response:

The calculations for the proposed ECM are as follows:

- Step one: Calculate half of the variance between the achieved ROE (after sharing) and approved ROE for year 4 and 5 of the MRPs; and
- Step two: Average the calculated amounts in step one and cap the average at 50 basis points.

By excluding the achieved ROEs in the first three years of the MRPs from the average calculation, the impact of the achieved ROEs in the first three years on the ECM is reduced. For instance if the achieved ROE in the first years of the plan are higher than the year 4 and 5 (which has been the case in the Current PBR plan), then excluding the first three years from the average will reduce the ECM. Nevertheless, some of the efficiencies from the first three years will continue to be reflected in the achieved ROEs in last two years. The purpose of the ECM is to find a balance in incentives between earlier and latter years of the plan and the proposed mechanism is designed to do that.

27.0 Reference: Exhibit B-1, page C-12, lines 30-36

FortisBC discusses an offramp based on ROE.

27.1 Please fully discuss how an offramp would be implemented if the thresholds were met. Would it be an automatic reopening of the MRP, to examine all components?

Response:

The financial off-ramp provision included in the Current PBR Plans and in the proposed MRPs is an automatic quantitative off-ramp, meaning that once the financial off-ramp is triggered, FortisBC expects that a review of the MRPs would take place to determine if elements of the Plans require change or whether the Plans are not operating as designed.

28.0 Reference: Exhibit B-1, page C-14, lines 19-29

28.1 Please provide the detailed calculations of the data in Footnote 115 in Excel format with formulae intact.

Response:

Please refer to the response to BCOAPO IR 1.1.1.

28.2 Please provide the actual and inflation adjusted O&M per customer for each of FEI and FBC for each of 2013-2018 along with the detailed calculation of each year.

Response:

Please refer to the response to BCOAPO IR 1.1.1.

28.3 On line 26, FortisBC states the O&M per customer spending is on a downward trend for each of FEI and FBC. Please fully explain why a productivity factor is not appropriate, given the historical downward trend.

Response:

Please refer to the response to BCUC IR 1.6.3.

29.0 Reference: Exhibit B-1, page C-16, line 1 to page C-17, line 18

FortisBC discusses increased costs related to a number of factors.

29.1 Please provide a detailed list of issues that drove costs in the last multiyear rate plan for each of FEI and FBC similar to the list included in pages C-16 and C-17.

Response:

As BCOAPO IRs 1.29.1, 1.29.2 and 1.29.3 appear to be focused on understanding some of the key factors that contributed to the success of FEI and FBC in managing total formula O&M in the Current PBR Plans, FortisBC provides an overall response here.

In the Current PBR Plans, the focus of FortisBC in the management of formula O&M expenditures has been one of pursuing productivity and achieving efficiencies for the benefit of customers and the Utilities. In this regard, as discussed in the Annual Reviews to date, both FEI and FBC have successfully undertaken a number of productivity initiatives. These include major initiatives, such as FEI's Regionalization and Project Blue Pencil, as described in Appendix B6 of the Application (FEI Report on Major Initiatives During the PBR Term). There has also been smaller initiatives such as the Sharing of Gas and Electric Contact Centre Staff and Advanced Distribution Management System, as discussed on pages 5 and 6 of the FBC Annual Review for 2019 Rates application, provided in Attachment 29.1. Other smaller productivity initiatives that have not been tracked and reported specifically are the result of FortisBC's broad-based, ongoing focus on productivity where resources are being deployed and roles and responsibilities are being broadened. Departments and employees are asked to review the way they operate to streamline processes and make it more efficient for our customers to do business with us. This broad-based productivity focus has helped to offset some of the cost increases and address the annual Productivity Improvement Factor (PIF) that is imposed as part of the formula O&M funding mechanism.

All the initiatives discussed have collectively contributed to the savings and benefits and helped to offset cost increases.

Some of the recent cost pressures as mentioned in the FBC 2019 Annual Review include approximately $0.1 million required for staffing to support the Customer Service Systems group and approximately $0.5 million for cyber security costs. For FEI, cost pressures described in the FEI 2019 Annual Review include: approximately $0.5 million for cyber security; approximately $1 million in 2018 to manage activities related to growth and aging of the Company's pipeline and distribution system; approximately $0.2 million per year for vehicle fuel and insurance costs in 2018 and 2019; and approximately $0.2 million per year for municipal fees and other expenses to meet municipal regulations in 2018 and 2019.

Consistent with FortisBC's approach in the Current PBR Plans to managing and tracking productivity improvements at a high level, FortisBC has not specifically tracked the different items that have contributed to addressing the PIF challenge and the smaller cost increases. FortisBC considers the smaller cost increases as part of normal business operations with the expectation that departments work collectively to manage the cost increases by finding ways to offset them.

29.2 Please provide the estimated annual O&M and Capital cost of each item listed in the response above for each year.

Response:

Please refer to the response to BCOAPO IR 1.29.1.

29.3 Please provide a list of cost reductions or efficiencies achieved in the last MRP.

Response:

Please refer to the response to BCOAPO IR 1.29.1.

30.0 Reference: Exhibit B-1, pages C-16 to C-17

30.1 Please confirm that FEI's and FBC's actual 2018 O&M costs provided sufficient resources to fund the 2018 level of activity required in each of the areas set out on pages C-16 (lines 14-38) and C-17 (lines 1-6) in order to operate the respective utilities.

Response:

FEI's and FBC's actual 2018 O&M costs funded the activities that were required in 2018. The cost pressures described on pages C-16 (lines 14-38) and C-17 (lines 1-6) of the Application relate to additional costs that FortisBC is anticipating during the term of the proposed MRPs, over and above the level of activity or costs experienced in 2018. Regardless of this cost pressure, FortisBC is not requesting incremental funding for these activities for the MRP term.

30.1.1 If not confirmed, please indicate for which areas 2018 funding was inadequate to meet 2018 needs, and the resulting implications.

Response:

Please refer to the response to BCOAPO IR 1.30.1.

30.2 Please confirm that, under the proposed MRPs for FEI and FBC, the annual inflation and customer growth factors will effectively provide increased funding for these activities each year.

Response:

As stated in the Application, the costs discussed on pages C-16 to C-17 are expected to be managed within the amounts provided by the indexing of O&M (no incremental funding is being requested). As these items, and other items that will arise, are over and above the amounts that will be provided by the indexing, FEI and FBC will be challenged to find savings and ways to do more with less.

31.0 Reference: Exhibit B-1, pages C-19 & C-20 and Exhibit B-1-1, Appendix A3-1

31.1 FEI states that it considers its bad debt expense of $0.9M in 2018 is unusually low, claiming that on average between 2014-2018 bad debt was about $1.8M per year. Please reconcile these claims with the information provided at line number 16 of Appendix A3-1 where it appears to show that for years 2013 to 2017 inclusive, FEI's bad debt expenses were $0.778M, $1.090M, $0.755M, $0.899M, and $0.700M respectively.

<u>Response:</u>

The numbers FEI states in regards to bad debt expense on pages C-19 and C-20 of the Application are included in line number 50 of Appendix A3-1, not line 16 as referenced in the question. Line 16 refers to operations expenses for Bad Debt Management Expenses.

Actual bad debt expenses from 2014 – 2018 are provided in the response to BCUC IR 1.25.7.

32.0 Reference: Exhibit B-1, pages C-22 & C-23 including Table C2-3

32.1 Please augment the referenced table by adding a row to show the associated O&M costs for digs each year.

Response:

Please refer to the response to BCUC IR 1.32.6 for the associated O&M costs for digs each year.

32.2 Please indicate where the costs for integrity digs can be found in Appendix A3-1 of Exhibit B-1-1.

Response:

The costs for integrity digs reside in accounts 120-21 Pipeline/Right of Way Operations and 120-31 Pipeline/Right of Way Maintenance in Appendix A3-1 of Exhibit B-1-1.

32.3 Why does FEI consider a range from $2.3M to $3.2M for integrity digs over the period from 2011 to 2018 to be too large to be forecastable?

Response:

Please refer to the response to BCUC IR 1.27.3 for the 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.

Please also refer to the response to BCUC IR 1.27.4 for elaboration of FEI's proposal to treat the costs of integrity digs outside of index-based O&M, similar to its other non-controllable O&M costs.

33.0 Reference: Exhibit B-1, page C-24, lines 1-6

33.1 Can FEI confirm that the reference to the IGU requiring additional integrity digs is simply to buttress its argument for keeping integrity digs out of base O&M?

<u>Response:</u>

Not confirmed. As discussed in the response to BCUC IR 1.27.5, and irrespective of the proposed IGU Project, there is considerable uncertainty related to scope, cost, timing and volume of expected digs during the proposed MRP term. The IGU Project will result in an uncertain number of additional integrity digs which is a material consideration to FEI's proposal to treat integrity digs outside of index-based O&M.

34.0 Reference: Exhibit B-1, page C-26, Table C2-5, page C-28, Table C2-6

34.1 Please show how the "Base" figures in the first referenced table are transformed into the "Adjusted Base" figures in the second.

Response:

As explained in Footnote 126 on page C-28, the Base amount of $9.469 million shown in Table C2-5 is inflated by the 2019 inflator factor of 1.02198 ($0.208 million) resulting in the value of $9.677 million shown as the Adjusted Base in Table C2-6.

Table C2-5 shows the total 2018 actual expenditures of $12.838 million, with the Base at $9.469 million compared to the Flow-through portion at $3.370 million. Under the proposed allocation approach shown in Table C2-5, the Base O&M has increased by approximately $3.177 million, from $6.291 million as reported in 2018, to $9.469 million. The Flow-through amount shown in Table C2-5 of $3.370 million has decreased by the same increase of $3.177 million, from $6.547 million as reported in 2018, to $3.370 million.

Table C2-6 shows only the Base O&M amount and does not include the Flow -through amounts which are updated annually. The Incremental Funding of $1.853 million shown in Table C2-6 represents the required incremental Base O&M funding to operate and maintain the LNG facilities. The sum of the Base amount ($9.677 million) and the Incremental amount ($1.853 million) described on page C-27 totals to $11.530 million, the total Base O&M required.

35.0 Reference: Exhibit B-1, page C-28

35.1 For each year 2014-2019 inclusive please provide a table showing FTEs for Tilbury, Mt. Hayes, and Supporting, broken down by role (e.g., maintenance, manager, etc.)

Response:

Provided below is a table showing average full-time equivalents (FTEs) for Tilbury, Mt. Hayes and Supporting functions for 2014-2019. The FTE is broken down by role and provides support to both base and flow-through liquefied natural gas (LNG) activities.

Role	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
LNG Tilbury						
LNG Plant Operators	11	11	13	17	21	22
LNG Millwrights	0	0	0	0	2	3
LNG Electrical & Instrumentation Technicians	1	1	1	2	3	4
LNG Administrative Assistants	1	1	1	1	1	1
Sub-total	**13**	**13**	**15**	**20**	**27**	**30**
LNG Mt. Hayes						
LNG Plant Operators	9	10	10	9	10	10
LNG Millwrights	0	0	0	0	0	1
LNG Electrical & Instrumentation Technicians	1	1	1	1	1	1
LNG Administrative Assistants	1	1	1	1	1	1
Sub-total	**11**	**12**	**12**	**11**	**12**	**13**
Supporting Functions						
Director, Gas Plant Operations & Major Projects	1	1	1	1	1	1
Manager, LNG Operations	1	1	1	1	1	1
Operations Manager, Tilbury	1	2	2	2	2	1
Operations Manager, Mt. Hayes	1	1	1	1	1	1
Process Safety Manager	0	0	0	0	0	1
Safety & Compliance Manager	0	0	0	0	0	0
Maintenance Manager	0	0	0	0	0	0
Manager, LNG Engineering	0	0	1	1	1	1
Mechanical Engineer	0	0	0	1	1	1
Process Engineer	0	0	0	1	1	1
Electrical & Instrumentation Engineer	0	0	0	0	0	1
Project Engineer	0	0	0	0	0	0
Sub-total	**3**	**4**	**5**	**7**	**7**	**8**
Total	**28**	**29**	**31**	**38**	**45**	**51**

35.2 For each year, 2014-2019 inclusive, please provide the actual O&M costs recovered in respect of Tilbury, Mt. Hayes, and Supporting.

Response:

The table below represents the actual O&M costs for Tilbury, Mt. Hayes and Supporting functions from 2014-2019.

LNG O&M Costs $ 000's	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
Formula O&M						
LNG Tilbury	2,749	2,668	2,723	2,193	2,134	2,346
LNG Mt. Hayes	2,777	2,846	2,861	3,018	2,767	2,836
Supporting Functions	692	686	648	955	1,391	1,455
Sub-total	**6,217**	**6,200**	**6,232**	**6,166**	**6,292**	**6,637**
Non-Formula O&M (Flow-through)						
LNG Tilbury	548	601	1,430	2,938	6,401	9,419
LNG Mt. Hayes	2	23	8	6	145	468
Sub-total	**550**	**624**	**1,438**	**2,944**	**6,547**	**9,887**
Total O&M	**6,767**	**6,824**	**7,670**	**9,110**	**12,839**	**16,524**

35.3 Given the large incremental costs being proposed for Tilbury, Mt. Hayes, and Supporting, is FEI convinced that reliability and safety have not been compromised due to too few FTEs?

Response:

The suggestion that the incremental ask for LNG operations is potentially evidence of compromised safety or reliability is incorrect. Safety is a core value at FortisBC and the planning and execution of all activities by the Company are completed in a manner that ensures safety and reliability. As described in the responses to BCUC IRs 1.28.9 through 1.28.13, the incremental positions proposed by FEI for Tilbury and Mt. Hayes are required to meet incremental requirements at those facilities in order to:

- Manage increased plant activities related to the Tilbury expansion, that is seven times larger than the Tilbury base plant;
- Conduct incremental maintenance and documentation as part of the evolving Safety and Loss Management Program requirements for LNG; and
- To address evolving reporting and safety protocol requirements.

Accordingly, the incremental ask addresses these requirements and will allow FEI to continue to manage in a manner that maximizes the safety and reliability of its operations.

35.4 Can FEI confirm that all incremental O&M costs will be inflated by both the inflation factor and the growth factor for the period of the proposed plan?

<u>Response:</u>

Confirmed for all costs included in Base O&M.

As indicated in the response to BCOAPO IR 1.34.1, the Incremental Funding of $1.853 million shown in Table C2-6 of the Application represents the required incremental Base O&M funding to operate and maintain the LNG facilities that has been included in the overall proposed FEI 2019 Base O&M.

Consistent with the overall proposed index-based O&M funding approach, an inflation factor will be applied to the 2019 Base O&M per customer (which as stated above includes the incremental LNG costs), which will also increase by the growth in customers.

36.0 Reference: Exhibit B-1, page C-29, Table C2-8

36.1 Please explain why the "Connect to Gas" expenses more than doubled from 2014 to 2015.

<u>Response:</u>

As noted in FEI's response to BCUC IR 1.30.3.1, under the Connect to Gas umbrella FEI carries out a broad range of activities to add and retain customers and deploys specific activities to address a particular challenge. The Connect to Gas expenses saw an increase between 2014 and 2015 due to increased spending on advertising and incentives.

During the 2014/2015 timeframe, policy at the local government level for the adoption of natural gas became more constraining. For instance, the City of Vancouver's Zero Emission Building Plan designed to make Vancouver a zero-emissions city made it restrictive for natural gas to be included in new construction projects, posing a significant threat to FEI's natural gas load and ability to add new customers. In response, FEI deployed various campaigns to educate customers about the benefits of using natural gas such as the "Gas is Good" campaign, which promoted the benefits of natural gas including its lower cost and increased comfort. These increased efforts to promote natural gas led to higher spending levels.

Finally, FEI also invested more funds in providing incentives to customers to encourage them to convert their energy systems to natural gas from other energy sources such as oil and propane.

36.2 Please explain how the Proposed 2019 amount for base "Connect to Gas" expenses was derived.

<u>Response:</u>

A number of factors were taken into consideration in deriving the 2019 Base amount. As noted in the response to BCUC IR 1.30.3.1, under the Connect to Gas umbrella, FEI undertakes the majority of its activities to add and retain customers. In calculating the Base amount for 2019 FEI looked at the historical activities and expenses incurred in 2018 and the expected spend in 2019 based on the market landscape. FEI also considered the activities it needed to carry out to remain competitive and continue to encourage the adoption of natural gas including incentives and advertising.

For example, FEI is planning to deploy the following initiatives in 2019:

- Conversion Incentives – FEI has a budget of $1.2 million and based on a projection of current uptake, there is increased interest in the program and as such the expected expenditure is now forecast to be approximately $1.9 million; and
- Advertising & Engagement activities for conversion and literacy – $0.5 million.

FEI notes that the activities and future spending could change based on the external factors in the market landscape.

36.3 Please provide a breakdown of actual 2019 "Connect to Gas" expenses including amounts spent on "Connect to Gas," "Natural Gas Appliance Incentives," and "Stakeholder Engagement."

Response:

A breakdown of actual Connect to Gas expenditures until the end of 2019 is not available. However, please refer to FEI's response to BCOAPO IR 1.36.2 for FEI's 2019 projected spend.

36.4 Please explain why the "In-house resources to address customer preferences" increased by a factor of more than 2.5 from 2014 to 2016, plummeted in 2017, then appeared stable at about 5.5 times the 2014 cost in 2018 and 2019.

Response:

Please refer to the response to BCUC IR 1.30.2.

36.5 Please explain how the Proposed 2019 amount for base "In-house resources to address customer preferences" was calculated.

Response:

The Proposed 2019 amount for "In-house resources to address customer preferences" was calculated based on two full-time positions with FEI's share $0.160 million (80 percent) and FBC's share $0.040 million (20 percent). Please refer to the response to BCUC IR 1.30.2 for reasons why these additional resources are necessary.

36.6 Please explain why the Proposed 2019 amount for base "In-house resources to address customer preferences" is more than eight times the actual amount spent on this line item in 2014.

Response:

Please refer to the response to BCUC IR 1.30.2.

36.7 Please explain how the proposed incremental amount for "In-house resources to address customer preferences" – which is more than three times the total amount spent on this line item in 2014 – was calculated and what, specifically the base and incremental amounts will be spent on.

Response:

Please refer to the response to BCUC IR 1.30.2.

36.8 Please explain why "Natural Gas Appliance Incentives" are not part of FEI's DSM/Conservation programs.

Response:

In its Decision on the Fortis Energy Utilities 2012-2013 Revenue Requirements Application, the BCUC determined (at page 209) that the Connect to Gas program (then called Switch and

Shrink) could not be included in the DSM portfolio because it did not meet the definition of "demand-side measures" in the *Clean Energy Act* and was a load building activity. The BCUC approved the Switch and Shrink expenditures instead as part of FEI's O&M expenditures.

37.0 Reference: Exhibit B-1, page C-36, Table C2-12

37.1 Please explain how the proposed 2019 amount – which is almost 10 times the highest amount spent in previous years – was calculated.

Response:

The Proposed 2019 amount of $0.984 million in Table C2-12 of the Application includes the Proposed Incremental amount of $0.888 million. FEI describes its proposed incremental funding for Indigenous Relations on pages C-36 to C-37 of the Application.

As discussed in detail in the responses to BCUC IR 1.1.1 and CEC IR 1.7.4, government policies such as UNDRIP and new Environmental Assessment requirements are expected to further increase, lengthen and expand the depth of Indigenous engagement required by FEI. FEI's service territory crosses more 150 Indigenous traditional territories and serves 56 Indigenous reserve communities. As such, when there are policy changes, the scope and breadth of these changes can have a large impact on FEI's resource requirements.

Given the increasing need for Indigenous engagement and support, FEI is expanding its Indigenous engagement activities in the following areas:

1) Relationship Protocol Agreements - $0.488 million;

2) Indigenous Community Investments - $0.200 million; and

3) Indigenous Supporting Resources - $0.200 million.

Relationship Protocol Agreements: As explained on pages C-36 to C-37 of the Application, FEI requires funding to enhance FEI's consultation with Indigenous communities and to begin modernizing Indigenous operating arrangements. FEI also requires increased legal costs for negotiations, engagement and capacity funding. FEI's $0.488 million incremental funding request is based on 2 additional positions for $0.200 million and support funding, including for legal capacity.

Indigenous Community Investments: As stated on page C-37 of the Application, additional funding for community investments and sponsorship is required to build capacity in the Indigenous communities in which we operate, and is also related to the changing external environment and increased expectations for engagement. It is necessary for FEI to increase its investment in this area due to the number of capital projects, increased expectations for engagement, and our desire to build capacity with our partner communities. FEI's incremental $0.200 million funding request is for increased community investment.

Indigenous Supporting Resources: FEI requires an Indigenous Employment Advisor to support HR activities to further our commitments to our Statement of Indigenous Principles in supporting the hiring of Indigenous contractors and employees, training and awareness. These amounts are for an advisor and a consultant to help support with the upcoming Indigenous land code issues – $0.160 million for an HR Advisor and $0.060 million for a consultant.

Please also refer to the responses to BCUC IR 1.1.1 and CEC IR 1.7.4 for further discussion of government policies and increased engagement requirements facing FortisBC.

37.2 Please provide support for the additional incremental O&M amount which will take 2019 base O&M to almost 20 times the maximum amount that FEI has ever spent in any year on these initiatives.

Response:

The 20 times figure is not correct. The information request does not accurately characterize FEI's proposed Incremental Funding for Indigenous Relations. Please refer to the response to BCOAPO IR 1.37.1.

38.0 Reference: Exhibit B-1 -1, Appendix B8-1, Table A:B8-1-5

38.1 For each delayed project in the referenced table, please provide the a list showing the updated versus original cost estimates.

Response:

Please refer to the response to BCUC IR 1.46.3.

In addition to those identified in the response to BCUC IR 1.46.3, the Tilbury LNG Plant Buildings project has been delayed to assess business requirements and site space strategy. No cost estimate is currently available for this project.

39.0 Reference: Exhibit B-1, page C-37, Table C2-13

39.1 For each of line items in the referenced table, please explain how the 2019 Base value was determined.

Response:

The column titled Base 2019 in the Table C2-13 represents FEI's 2019 Projection and the existing funding for that area available in 2019 under the Current PBR Plan for each of the line items.

Please refer to the response to BCUC IR 1.39.4 for discussion of how the values in the tables (e.g., C2-12, C2-13) show how the incremental funding requests in the Application were determined, including the column titled Base 2019.

40.0 Reference: Exhibit B-1, page C-37, Table C2-13, and pages C-38 to C-42

40.1 Ignoring the fact that FEI is also applying for incremental funding for Integrity Management to start off the next PBR scheme, please explain, providing sufficient details in support, why Integrity Management costs more than doubled from 2014 to 2019.

Response:

The Base 2019 of $6.2 million compared to the 2014 Historical Expenditure of $3.5 million represents an increase of 177 percent, and thus costs have not "more than doubled" as suggested by the question.

The increased Integrity Management expenditures from 2014 to 2019 were necessary to support the activities required to maintain the safety and reliability of FEI's transmission pipeline system. These activities are developed by or under the direct supervision of Professional Engineers, with consideration to factors including applicable regulations and standards, industry practice, and results of prior inspections. FEI holds paramount the safety, health and welfare of the public and the protection of the environment.

The following were the primary drivers for increases in expenditures over this period:

- Increases for engineering analysis (i.e., labour), due to increased quantities of in-line inspection data;
- Increases in geotechnical and hydrotechnical inspections and assessments to improve proactive hazard management, due in part to longer lead times required to implement necessary mitigation projects (e.g. environmental permits);
- Increases in seismic assessments to ensure an accurate understanding of this potential hazard, due in part to the publication of a 5th Generation Canada seismic hazard model in 2015 by the Geologic Survey of Canada; and
- Increases in indirect inspections for cathodic protection (CP) system evaluation, due to results of prior inspections requiring additional surveys to confirm CP system performance as well as to increases in the quantities of data collected during above-ground surveys.

The activities that comprised FEI's Integrity Management expenditures remained consistent throughout the 2014 to 2019 period; however, the required activity levels were subject to changes/fluctuations in accordance with priorities established by FEI's Integrity Management group.

40.2 Please confirm that FEI has been in compliance with CSA Standard CSA Z662-15 continuously since 2014; if unable to confirm, please explain.

Response:

The BC OGC conducts periodic assessments of FEI's integrity management program and, if deficiencies are identified, FEI takes corrective action to the satisfaction of the BC OGC. Please also refer to the response to BCUC IR 1.32.3.

40.3 When did CSA Z662-15 become effective?

Response:

As the CSA Z662-15 standard is dated June 2015, FEI interprets that the standard became effective in June 2015. CSA Z662 is defined in the BC Pipeline Regulation (B.C. Reg. 147/2014) as the standard published by the Canadian Standards Association as CSA Z662, Oil and Gas Pipeline Systems, as amended from time to time.

40.4 Please explain how it could be determined that a pipeline operator did not "continually improve practices" and, as such, was in contravention of CSA Z662-15.

Response:

FEI's Integrity Management Program is a comprehensive management system, and as such encompasses periodic management reviews and internal audits. These reviews provide opportunity for the identification of continual improvements, as well as for verifying the effectiveness of previously implemented improvements.

FEI is also subject to periodic reviews by the BC OGC through their compliance verification processes. Through such regulatory processes, the BC OGC could determine that a pipeline operator did not "continually improve practices" and, as such, was in contravention of CSA Z662-15.

40.5 Does FEI agree that the criterion "continually improve practices" is somewhat subjective and up to the utility's discretion?

Response:

FEI does not agree that the criterion, 'continually improve practices', is somewhat subjective and up to the utility's discretion. Continuing to improve the FEI Integrity Management Plan (IMP) to remain in compliance with CSA Z662-15 and adopt industry practices is an objective requirement and is not at the discretion of FEI.

FEI is obligated by the CSA Z662-15 standard (Clause 3.1.2 h) 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. The following is an excerpt from a whitepaper recently published by JANA Corporation, an expert risk consultant:

> 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.[6]

Customers expect FEI to be a safe reliable energy provider and continually improve practices.

40.6 How does FEI ensure that the changes in Integrity Management practices that it adopts lead to "improvement" as opposed to simply spending more money on the initiative?

Response:

Please refer to the response to BCOAPO IR 1.40.4.

[6] http://www.janatechnology.com/integrating-qra-outputs-into-pipeline-integrity-management-decision-making.

40.7 Please provide details as to how FEI continually improved Integrity Management practices in each year over the period 2014-2019.

Response:

The following are continual improvements to FEI's Integrity Management practices that were implemented over the Current PBR Plan term 2014-2019, or immediately prior.

Since approximately late 2013 onward:

- FEI adopted circumferential magnetic flux leakage technology for all in-line inspected pipelines. FEI discussed this improvement in the response to BCUC IR 1.9.9.2 in the FEI Annual Review for 2017 Rates proceeding. Please refer to the response to BCUC IR 1.43.2 for a copy of that response.

Since approximately 2014 onward:

- 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 for a table of projects related to enhancing ILI capabilities on CTS pipelines that were executed during the PBR term. Please refer to the response to BCUC IR 1.43.2 for a copy of that response.

Since approximately 2015 onward:

- 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.
- FEI implemented changes to its geotechnical and hydrotechnical inspections and assessments to improve proactive hazard management;
- FEI identified incremental mitigation to address the potential for rupture due to external corrosion for pipelines of NPS 6 and larger and operating at 30 percent SMYS or greater, as applied for within its Inland Gas Upgrades CPCN Application;
- Supplemental to FEI's management reviews of its IMP-P, FEI has implemented monthly management reviews of its business performance. These reviews were initiated by

FEI's management to ensure line-of-sight and timely knowledge on asset and operations matters, including those related to pipeline integrity;

- FEI published an IMP-P activity standard for "Management of Change" (MOC), which has embedded this activity within FEI's integrity management system framework. This improvement was identified through FEI's participation in the BC OGC compliance verification process for its Integrity Management Program for pipeline assets.
- FEI published an IMP-P activity standard for "IMP-P Risk Management", creating a process for the identifying and qualitatively assessing potential site-specific integrity-related risks. This improvement was identified through FEI's participation in the BC OGC compliance verification process for its Integrity Management Program for pipeline assets.
- FEI published an IMP-P activity standard for "IMP-P Audits and Assessments", creating a formal internal audit program for FEI's Integrity Management Program for pipeline assets. This improvement was identified through FEI's participation in the BC OGC compliance verification process for its Integrity Management Program for pipeline assets.

Since approximately 2016 onward:

- FEI is undertaking seismic assessments using the 5th Generation Canada seismic hazard model, published in 2015 by the Geologic Survey of Canada. This work is to ensure an accurate understanding of this potential hazard.
- FEI modified its methodology for its cathodic protection (CP) evaluation program by collecting increased data on CP performance and coating quality, as well as by applying objective dig selection criteria for non-piggable pipelines. This is consistent with industry practice.

Since approximately 2017 onward:

- FEI developed and implemented internal on-line courses for staff involved in the implementation of IMP-P activities to ensure alignment with and understanding of IMP-P objectives, as well as to build safety culture with respect to integrity management.

Since approximately 2018 onward:

- FEI began using a laser scanner for measuring and recording corrosion and dent imperfections at integrity dig sites. This improvement is in line with industry practice, and provides improved accuracy of in-ditch measurements for failure calculations and ILI tool validation;

- FEI is currently developing the Transmission Integrity Management Capabilities (TIMC) Project to enable in-line inspection of prioritized transmission mainlines with tools capable of detecting stress corrosion cracking or other crack-like imperfections in gas pipelines, and to improve FEI's capabilities with respect to quantitative risk management of transmission pipelines;

Since approximately 2019 onward:

- FEI has developed and implemented improved processes for its integrity incident management to provide improved consistency of data capture and compliance to regulatory reporting requirements.

40.8 Does FEI not consider that improving Integrity Management is a core requirement for a regulated utility?

Response:

FEI considers that improving Integrity Management is a core requirement for utilities falling under the BC Pipeline Regulation (B.C. Reg. 147/2014), for the reasons outlined in the response to BCOAPO IR 1.40.5.

40.9 Can FEI confirm that "Maintaining System Infrastructure" is not a new (for 2019) utility requirement?

Response:

Please refer to the response to BCUC IR 1.32.2 for a discussion of system maintenance, safety and integrity during the Current PBR Plan term. FEI has proposed $0.700 million in additional funding for maintaining system infrastructure related to increasing line heater inspections on Vancouver Island, and an additional Maintenance Planning Engineer and Maintenance Planner to meet increasing requirements related to asset planning. Please refer to the response to BCOAPO IR 1.40.12 for additional detail.

40.10 Given that FEI has been spending about $40M per year on "Maintaining System Infrastructure" since 2014 on, does FEI not currently employ staff to perform maintenance planning activities?

Response:

FEI currently employs staff to perform maintenance planning activities, including a Senior Maintenance Planning Engineer, 5 Asset Management Analysts, and 3 Maintenance Planners. However, as noted on page C-39, FEI's request for additional funding is related to increased requirements for Vancouver Island line heater inspections, and to hire a Maintenance Planning Engineer, and a Maintenance Planner. FEI has requested an incremental amount of $0.700 million to fund these requirements. Please refer to the response to BCOAPO IR 1.40.11 for further discussion on staffing to perform maintenance planning activities.

40.11 Please provide a breakdown of 2019 actual "Maintaining System Infrastructure" expenses and FTEs involved in this activity.

Response:

A breakdown of the 2019 actual expenses and FTE for Maintaining System Infrastructure will not be available until after year end.

A breakdown of 2018 actual expenses and FTE for Maintaining System Infrastructure is as follows:

Activity	Expenditure	FTE
Preventative Maintenance	$33.000 million	125
Corrective Maintenance	$10.200 million	48
Total	$43.200 million	173

Preventative maintenance are the activities to prevent assets from breaking down. Corrective maintenance are the activities to fix assets.

40.12 Please provide a breakdown of the additional $0.700M that FEI is requesting in incremental "Maintaining System Infrastructure" costs.

Response:

The following table is a break down of the additional $0.700 million that FEI is requesting in incremental 'Maintaining System Infrastructure' costs:

Additional Request Items	Proposed Amount
Vancouver Island line heater inspections	$0.450 million
Maintenance Planning Engineering	$0.150 million
Maintenance Planner	$0.100 million
TOTAL	$0.700 million

Please refer to Section C2.4.2.3.4 page C-39 for a more detailed description of these items.

40.13 Please provide a breakdown of the additional $0.700M that FEI is requesting in incremental "Operations Compliance and Safety" costs.

Response:

The following table is a break down of the additional $0.600 million (not $0.700 million) that FEI is requesting in incremental Operations Compliance and Safety costs:

Additional Request Items	Proposed Amount
Vehicle Safety	$0.200 million
Encroachments	$0.100 million
BC One Call	$0.180 million
Construction Crew Resources	$0.120 million
TOTAL	$0.600 million

Please refer to Section C2.4.2.3.4, page C-39 of the Application for a more detailed description of these items.

40.14 Regarding Gas Control, does FEI agree that this is an essential gas utility activity?

Response:

FEI confirms that Gas Control is an essential gas utility activity.

40.15 Please provide the number of FTEs that FEI has employed for each year from 2014 to 2019, in performing Gas Control activities.

Response:

The table below provides the number of FTE funded via the Gas Control cost centre O&M for 2014-2019.

Gas Control - 2014-2019 FTE (Full Time Equivalents)

	2014 FTE	2015 FTE	2016 FTE	2017 FTE	2018 FTE	2019 FTE
M&E	-	-	-	1	2	2
MoveUP	10	11	12	11	11	12
TOTAL FTE	**10**	**11**	**12**	**12**	**13**	**14**

40.16 In FEI's view, were the resources allocated to Gas Control adequate in past years?

Response:

FEI believes the resources allocated to Gas Control in past years were appropriate and allowed FEI to meet the requirements of its customers and to operate in a safe and reliable manner.

FEI also continuously evaluates system complexity and its operational environment, and takes steps to adjust staffing levels accordingly.

40.17 Please explain why gas control costs increased by about 50 percent from 2014 to 2019.

Response:

The primary drivers of the increased Gas Control cost centre O&M costs from 2014 Actuals to 2019 Base, as shown in Table C2-13, are as follows:

2015

- Amalgamation of gas utilities resulted in reclassification of FEVI-related gas control costs to O&M.
- Supervisory Control and Data Acquisition (SCADA) support (MoveUP) position added to support the SCADA system and increased amount of telemetry.

2016

- Temporary Gas Controller (MoveUP) position added to ensure certified replacement gas controller available for a planned gas controller retirement.

2017

- Temporary Gas Controller (MoveUP) position removed when retirement position filled.
- Gas Control and SCADA Manager (M&E) position transferred into Gas Control cost centre from another cost centre.

2018

- One SCADA technician (MoveUP) position transferred to another cost centre; offset by one Gas Controller (MoveUP) position added to support increasingly complex operational environment.
- Gas Control Supervisor (M&E) position added to support best practices gas control operations and control room procedures.

2019

- One additional Gas Controller (MoveUP) position planned to support increasingly complex operational environment.

Please also refer to the response to BCUC IR 1.32.2.

40.18 Regarding the CEPA Participation costs, when did FEI become a member?

Response:

FEI became a member of the Canadian Energy Pipeline Association (CEPA) in 2008. At that time, FEI joined as a Technical Member (as opposed to a Full Member). Technical Members were provided access to participate in technical committees, but could not vote or participate in the organization's strategic direction as established by their Board.

Over the past number of years, CEPA has been developing and implementing a framework to drive industry-level continual improvement and benchmarking, known as Integrity First®. In accordance with this direction, effective 2019 CEPA replaced its Technical Member option with a membership classification known as Integrity First Partner. FEI is a CEPA Integrity First Partner effective 2019, and the corresponding cost of CEPA membership increased from $0.100 million to $0.226 million.

The increase in membership fee of $0.126 million accounts for the incremental $0.100 million included in the Base 2019 in Table C2-13 on page C-37 of the Application, noting that rounding was applied to this value.[7]

FEI clarifies that the incremental $0.700 million as discussed on page C-42 of the Application is comprised of $0.100 related to CEPA membership, $0.300 million related to additional resources for Integrity Management, and $0.300 million for Gas Control costs to align with industry standard practice as identified through the FEI Integrity First Partner membership.

[7] FEI's CEPA membership fee of $0.100 is part of the "Integrity Management" line item for the years 2014-2018 and continues to be included in that line item for the 2019 base and 2019 proposed.

40.19 Please provide the annual cost to FEI of CEPA membership fees.

Response:

Please refer to the response to BCOAPO IR 1.40.18.

40.20 Please provide a breakdown of the actual 2019 CEPA Participation costs of $0.100M.

Response:

Please refer to the response to BCOAPO IR 1.40.18.

40.21 Is the $0.165M proposed for an additional gas control employee on page C-42 not included in the Gas Control row in Table C2-13?

Response:

The $0.165 million proposed for an additional gas control employee on page C-42 is not included in the "Gas Control" row in Table C2-13.

The incremental funding proposed at the "CEPA Participation" row in Table C2-13 is separate from and in addition to the incremental funding proposed at the "Gas Control" row in Table C2-13.

Please also refer to the response to BCUC IR 1.33.1. The incremental funding at the "CEPA Participation" row in Table C2-13 is for costs which are directly related to and driven by FEI becoming a CEPA member.

41.0 Reference: Exhibit B-1, page C-43

41.1 With respect to page C-43, please provide a copy of Finance Schedule 3 per FBC's Compliance Filing Order G-246-18 for the Annual Review of 2019 Rates.

Response:

Please refer to Attachment 41.1.

41.2 If the requested schedule does not provide the derivation of the 2019 formula inflation factor (1.02382 per Table C2-14) in sufficient detail to explain why it varies from the 1.02376 value in FBC's Annual Review for 2019 Rates Application (page 17), please provide an explanation.

Response:

At the time that FBC filed its materials for the Annual Review for 2019 Rates, the June 2018 AWE index had yet to be complied by Statistics Canada, which has been the case throughout the term of the Current PBR Plan. Each year, through the term of the Current PBR Plan, both FEI and FBC have filed evidentiary updates that include the final July – June AWE indices resulting in updated I-factors. On October 3, 2018, FBC filed an Evidentiary Update to its Annual Review for 2019 rates which included an updated I-factor (from the updated June 2018 AWE index). The Evidentiary Update filed as B-2-2 in that proceeding shows the growth factor of 1.02382.

42.0 Reference: Exhibit B-1, page C-44

42.1 If the Corporate/Shared Services Studies impact of $0.705 M is a 2019 value (per Footnote 131), why is the impact included in the Adjusted 2018 O&M Base and then subjected to the 2019 Inflator as opposed to being included as one of the 2019 adjustments?

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.24.1 and 1.146.1.1.

43.0 Reference: Exhibit B-1, pages B-33 and C-44

43.1 Please confirm that, based on Table B2-3, FBC expects to achieve O&M savings for $0.5 M in excess of the "formula savings" in 2019.

Response:

The estimated 2019P $0.5 million O&M savings shown in Table B2-3 of the Application represents the expected savings when compared to the 2019 formula allowed funding. In Table B2-3, the specific wording used to describe this is 'Savings Above the Formula'. If the reference to '…. in excess of the "formula savings" in 2019' in this question is intended to refer to the 'Savings Above the Formula', then it is confirmed correct.

43.2 Please confirm that the proposed approach for establishing the 2019 Base O&M does not capture any of the 2019 O&M saving that are in excess of the "formula". If not confirmed, please explain why.

Response:

Not confirmed. All permanent savings are captured, although it is not possible for FBC to differentiate between those savings that were above the formula and those savings that were related to the PIF in establishing the 2019 Base O&M.

FBC's 2019 Base O&M for the proposed MRP incorporates the permanent savings through the Adjusted 2018 Base O&M starting point. FBC's Adjusted 2018 Base O&M includes 2018 permanent O&M savings of approximately $0.44 million (i.e., 2018 overall formula savings was $0.94 million with $0.50 million temporary and the remaining $0.44 million permanent) that are expected to carry over to 2019.

43.3 Please explain why the 2019 Base O&M should not be reduced by $0.5 M to account for these additional savings.

Response:

As discussed in the response to BCOAPO IR 1.43.2, the permanent savings have already been incorporated into the 2019 Base O&M.

44.0 Reference: Exhibit B-1, page C-45 and Appendix A3-2

44.1 With respect to Appendix A3-2, please indicate where bad debt expense (as referenced on page C-45) is included and what the actual values are for each year 2013-2018 as well as forecast for 2019.

Response:

FBC bad debt expense as referenced on page C-45 of the Application is included in line 35 of Appendix A3-2 under Account 904 Credits & Collections. Actual bad debt expenses from 2014 to 2018 and forecast for 2019 are provided in the response to BCUC IR 1.35.2.

45.0 Reference: Exhibit B-1, page C-46

FBC 2017 RDA, Exhibit B-8, BCUC 97.1

45.1 Please update the table in BCUC 97.1 to include all of 2018 and the months in 2019 for which data is available.

Response:

The table below provides data to April 30, 2019.

Year	Month	RO Count	RO Read Costs ($000s)	RO Read Fee ($000s)	Cumulative Net: Costs - Fee ($000s)
Balance at December 31, 2015					**$ (1.7)**
2016	January	2,994	27.9	16.9	11.0
	February	2,991	29.8	12.4	17.4
	March	2,862	32.0	15.9	16.1
	April	2,865	30.1	37.5	(7.4)
	May	2,857	22.4	22.8	(0.4)
	June	2,835	26.2	26.9	(0.7)
	July	2,827	25.5	23.0	2.5
	August	2,828	25.8	25.0	0.8
	September	2,814	25.3	24.9	0.4
	October	2,789	19.8	22.4	(2.6)
	November	2,774	30.3	21.3	9.0
	December	2,759	31.3	24.4	6.9
	Total		**326.6**	**273.3**	**53.3**
2017	January	2,750	34.8	21.5	13.3
	February	2,739	31.8	18.7	13.1
	March	2,724	33.7	22.8	10.9
	April	2,707	30.9	21.3	9.6
	May	2,700	35.2	21.6	13.6
	June	2,690	23.4	22.9	0.5
	July	2,669	24.4	22.9	1.5
	August	2,653	25.6	23.8	1.8
	September	2,649	21.5	18.1	3.4
	October	2,628	20.8	21.5	(0.7)

Year	Month	RO Count	RO Read Costs ($000s)	RO Read Fee ($000s)	Cumulative Net: Costs - Fee ($000s)
	November	2,627	17.1	14.0	3.1
	December	2,618	15.9	17.7	(1.8)
	Total		**315.1**	**246.8**	**68.3**
2018	January	2,610	17.6	20.6	(3.0)
	February	2,605	22.2	19.5	2.7
	March	2,589	14.1	13.6	0.5
	April	2,563	22.4	21.8	0.6
	May	2,551	25.1	15.8	9.3
	June	2,537	21.0	22.2	(1.2)
	July	2,525	19.6	23.6	(4.0)
	August	2,516	13.6	19.7	(6.1)
	September	2,484	30.3	12.8	17.5
	October	2,471	21.7	28.1	(6.4)
	November	2,463	21.0	11.4	9.6
	December	2,452	23.1	21.2	1.9
	Total		**251.8**	**230.1**	**21.7**
2019	January	2,449	33.8	21.3	12.5
	February	2,430	20.9	19.8	1.1
	March	2,420	22.4	19.1	3.3
	April	2,411	23.5	23.2	0.3
	Total YTD		**100.5**	**83.4**	**17.1**
Grand Total					**$ 158.7**
After-Tax Deferral Account Balance					**$ 117.1**

46.0 Reference: Exhibit B-1, pages C-32, C-35 to C-36 and C-47

46.1 With respect to page C-47 (line 8), please confirm the reference to Section 2.4.3.2 is correct.

Response:

The reference to Section 2.4.3.2 is incorrect. The corrected reference should be to Sections C2.4.2.3.1 Customer Expectations and C2.4.2.3.2 Engagement.

46.2 Page C-32 makes reference to additional in-house resources including a Digital Advisor and Communications Writer/Researcher being required at a cost of $0.200 M. Page C-35 makes reference to funding being required for an additional Digital Communications Advisor position. Is the positon referenced on page C-35 different and incremental to the position(s) referenced on page C-32?

Response:

Confirmed. Please refer to the responses to BCUC IRs 1.30.25 and 1.31.14.

46.2.1 If yes, please explain why.

Response:

Please refer to the response to BCOAPO IR 1.46.2.

46.2.2 If no, please confirm the $0.08 M in Table C2-15 should be $0.04 M.

Response:

The amount in Table C2-15 is correct. The table includes $0.080 million for FBC's share of:

- $0.040 million related to Digital Advisors and Communications Writer/Researcher for In-house Resources to Address Customer Communications Needs (page C-32, line 28); and
- $0.040 million related to Digital Advisor for Other Supporting Resources (page C-36, lines 4-5).

Please also refer to the response to BCUC IR 1.31.14 for discussion on the differences between these two incremental funding proposals.

47.0 Reference: Exhibit B-1, pages C-47, Table C2-16

47.1 For each of line items in Table C2-16, please explain how the 2019 Base value was determined.

Response:

Please refer to the response to BCOAPO IR 1.39.1.

48.0 Reference: ExhibitB-1, pages C-47 to C-48

48.1 Please provide a schedule that contrasts the annual values (2013-2018) for SAIDI and SAIFI for: i) FBC's overall service area and ii) the Kootenay area.

Response:

Please see the table below that shows the annual values from 2013 to 2018 for SAIDI and SAIFI for FBC's overall service area and for the Kootenay area. Note that the data is not normalized and includes the impact of major events.

Compared to the rest of the FBC service area, the Kootenay region presents a number of challenges related to managing the frequency and duration of outages. Transmission and distribution infrastructure that serves communities across the Kootenays covers long distances, often across mountainous terrain which can be heavily forested. When tree contacts occur, line crews need to travel longer distances, frequently with difficult access, to patrol the line and make repairs prior to restoring power.

	2013	2014	2015	2016	2017	2018
FortisBC Total SAIDI	2.92	3.93	4.53	2.51	5.41	3.86
Kootenay Area SAIDI	7.26	3.92	9.98	4.67	11.18	7.89
FortisBC Total SAIFI	1.35	2.08	1.83	1.40	2.04	1.82
Kootenay Area SAIFI	2.87	2.64	3.51	1.86	4.53	4.09

48.2 Does FBC track the reasons for outages by cause and specifically, those related to trees?

Response:

Yes, FBC does track the reasons for outages by cause and those related to trees.

Please see the table below that shows the annual values from 2013 to 2018 for SAIDI and SAIFI attributable to tree contacts for FBC's overall service area and for the Kootenay area. The data is not normalized and includes the impact of major events.

	2013	2014	2015	2016	2017	2018
FortisBC SAIDI (Tree Contacts)	1.00	0.87	1.12	0.79	1.18	1.50
Kootenay Area SAIDI (Tree Contacts)	2.73	1.31	3.61	1.61	4.14	3.79
FortisBC SAIFI (Tree Contacts)	0.45	0.44	0.44	0.44	0.36	0.39

	2013	2014	2015	2016	2017	2018
Kootenay Area SAIFI (Tree Contacts)	1.22	0.63	1.42	0.93	1.28	1.15

48.2.1 If not, what is the basis for claiming FBC is experiencing a high number of outages in the Kootenay area from trees falling on the conductor?

Response:

Please refer to the response to BCOAPO IR 1.48.2.

48.2.2 If yes, please provide a schedule that contrasts the annual values (2013-2018) for SAIDI and SAIFI attributable to tree/trees falling for: i) FBC's overall service area and ii) the Kootenay area.

Response:

Please refer to the response to BCOAPO IR 1.48.2.

48.3 Will the incremental funding for a qualified profession to map root rot be required for the entire MRP period?

Response:

Yes, root rot is a growing problem in certain parts of the FBC service territory. FBC expects that funding for root rot surveys will be required for the entire MRP period.

48.3.1 If yes, why?

Response:

Please refer to the response to BCOAPO IR 1.48.3.

48.3.2 If not, for what years is required?

Response:

Please refer to the response to BCOAPO IR 1.48.3.

48.4 The inclusion of the incremental funding requirement for a qualified professional in the 2019 base means that the cost to customers will be increased each year not only by inflation but also by customer growth. Please explain why the latter increase is necessary.

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.

49.0 Reference: Exhibit B-1, page C-48

49.1 Please explain more specifically how the $0.232 M for Generation Dam Safety will be used for (e.g., is it for additional staff and, if so, how many and what would be their roles?).

Response:

Please refer to the response to BCUC IR 1.39.8.

49.2 At what frequency are dam safety reviews required and, based on the number of FBC dams, how many on average would this translate into on an annual basis?

Response:

The frequency of dam safety reviews depends on the dam failure consequence classification. All four FBC dams are classified as extreme consequence, and therefore dam safety reviews are required at a minimum of every seven (7) years. On an average basis, this represents one dam approximately every 1.75 years.

49.3 How many dam safety reviews were completed in each of the years from 2013 to the end of 2018?

Response:

FBC completed one Dam Safety Review in 2013. The Dam Safety Regulations did not require other Dam Safety Reviews in the 2013 - 2018 period.

49.4 How frequently are condition assessments of the penstocks required?

Response:

FBC performs condition assessments of the penstocks during Major Unit Inspections that occur approximately every 10 years. More frequent assessments are undertaken if required.

49.5 Is it that no condition assessments of the penstocks have been undertaken or that such assessments have been undertaken but records have not been kept?

Response:

FBC has performed condition assessments of the penstocks and records were created; however, they cannot be located as FBC did not have a consistent or centralized electronic document control process at the time. FBC has since updated its penstock document control processes to address this issue going forward based on BC Dam Safety Regulations and best practices provided by the Canadian Dam Association (CDA).

49.6 If they are necessary, are the costs of penstock construction, upgrades or repair included in FBC's dam related CPCN applications?

Response:

The costs of penstock construction, upgrades and repairs are generally included in Sustainment capital expenditures and would only be included in FBC's dam-related CPCN applications if they are part of a capital project that meets the requirements for a CPCN application.

49.7 Please explain whether penstock assessments are part of a dam safety review.

Response:

Penstock condition assessment are not part of a Dam Safety Review. Penstock assessments require a unit outage and dewatering of the penstock, which cannot always be scheduled at the time when the Dam Safety Review is undertaken.

49.7.1 If not, please explain why it is not.

Response:

Please refer to the response to BCOAPO IR 1.49.7.

50.0 Reference: Exhibit B-1, page C-48

50.1 At what rate does the apprenticeship program need to produce Trade Administration apprentices in order to meet anticipated demand and what is the basis for the anticipated demand for such apprentices?

Response:

The FBC apprenticeship program needs to produce approximately three graduates per year. The basis for the anticipated demand is the projected retirements and promotion of high potential Journeyman, combined with the fact that it takes four years for an apprentice to become a Journeyman.

50.2 Please provide a schedule that sets out the number of Trade Administration apprentices in the program each year and the number of apprentices "graduating" from the program each year (2013-2018).

Response:

The number of Trade Administration apprentices in the program each year and the number of apprentices graduating from the program is shown in the following table:

Year	Trade Administration Apprentices in the program	Trade Administration Apprentices graduating
2013	10	0
2014	12	0
2015	9	3
2016	7	2
2017	7	3
2018	6	4

For greater context, there were 10 apprentices in the program in 2013 in various states of completion. FBC added 4 more apprentices in 2014 and 2 left the company. In 2015, 3 graduated from the program and in 2016, 2 more graduated. In 2017, 3 apprentices graduated and 3 apprentices were added to the program. In 2018, 4 apprentices graduated and FBC added 3 more apprentices to the program. The program is 4 years and in some cases, apprentices can take an extra year to complete their program.

50.3 What is FBC's success rate at: i) retaining apprentices during the program and ii) retaining apprentices once they have completed the program?

Response:

FBC has been successful retaining apprentices during the program. FBC has indentured 20 apprentices since 2012:

- 2 apprentices left the program in the first year of their apprenticeship;
- 12 apprentices have completed the program and remain with FBC; and
- 6 apprentices are expected to graduate in the coming years.

50.4 The inclusion of the incremental funding requirement for additional apprentices in the 2019 base means that the cost to customers will be increased each year not only by inflation but also by customer growth. Please explain why the latter increase is necessary.

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.

51.0 Reference: Exhibit B-1, pages C-40 and C-48

51.1 At page C-40 the total incremental Cyber Security cost for FEI and FBC is set out as \$0.508 M with \$0.450 for additional positions leaving \$0.068 M for managed tools and services. At page C-48, FBC's share of the cost for managed tools and services is stated to be \$0.062 M. Please explain why virtually all of the cost for managed tools and services is attributed to FBC.

Response:

FortisBC clarifies that the \$0.150 million per position noted on page C-40 of the Application represents the overall cost per position before allocation to FEI/FBC and any capitalization.

Therefore, the total incremental cybersecurity for FEI is \$0.508 million, consisting of \$0.342 million for new positions and \$0.166 million for managed tools and services.

The total incremental cybersecurity for FBC is \$0.080 million, consisting of \$0.018 million for a new shared position and \$0.062 million for managed tools and services for FBC.

The ratio of managed tools and services is approximately 25 percent for FBC and 75 percent for FEI.

52.0 Reference: Exhibit B-1, pages C-40 and C-48

52.1 Is spending on Data Analytics expected to improve work/employee efficiency at FBC and FEI?

Response:

The specific goals of data analytics are as described on page C-40, lines 35-36 and page C-41, lines 1-5 of the Application. Initiatives that FortisBC has identified to date can be found on page C-41 and C-48 of the Application. Some initiatives may improve work and employee efficiency, but others may accomplish different goals such as reducing the duration of customer outages. No targets have been set for any labour savings.

52.1.1 If yes, please explain how.

Response:

Please refer to the response to BCOAPO IR 1.52.1.

52.1.2 What is the anticipated value (dollar or FTE savings) associated with this efficiency improvement?

Response:

Please refer to the response to BCOAPO IR 1.52.1.

52.2 How much of the incremental Data Analytics funding is for additional staff (per page C-40, line 34)? Please break down your response by utility: i.e. number for FBC and FEI respectively.

Response:

The requested funding is specifically for additional staff required to support the increasing use of data analytics at FortisBC. The additional staff will be shared by FEI and FBC. The $0.300 million represents FEI's portion of the levelized, pre-capitalization, average annual amount for an additional one FTE per year during the term of the MRP for FEI. FBCs share of the additional costs is $0.099 million.

53.0 Reference: Exhibit B-1, page C-53

53.1 What is the anticipated timing for the implementation and application of the AIP tool to electric assets? If the timing is phased based on type of assets, please indicate the timing of the different phases and the types of assets to be included at each phase.

Response:

The Asset Investment Planning tool is anticipated to be implemented for electric assets by the end of 2019.

54.0 Reference: Exhibit B-1, page C-58, Tables C3-1 and C3-2

54.1 Please provide the forecasted values for each item in both of the referenced tables.

Response:

FEI has not produced a forecast of new customer connections nor produced a forecast of Growth capital new customer mains, services, meters and system improvements for years 2020 through 2024 for the Application. The Application sets out the framework and mechanism by which inflation-indexed Growth capital (for FEI only) will escalate Base Growth capital over the MRP term. At each Annual Review, FEI will forecast gross customer additions for the upcoming year to determine Growth capital. This mechanism will allow FEI to bring forward the most current forecast information on customer growth and attachments based on the most up-to-date operating environment and market trends.

54.2 Please augment Table C3-1 by adding a column for forecasted 2019 spending.

Response:

Please see the table below with the addition of 2019 projected spending for Growth capital expenditures.

FEI Growth Capital Expenditures 2014-2019 ($000s)

Growth Capital	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projection
New Customer Mains	8,420	13,752	12,823	16,467	24,494	20,019
New Customer Services	24,675	30,064	31,246	39,149	53,993	44,752
New Customer Meters	1,583	1,960	3,430	3,927	4,397	4,215
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433	2,793
Subtotal Growth (Gross)	37,117	51,499	50,452	63,108	87,316	71,779
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)	(2,742)
Total Growth (Net)	33,360	48,694	47,947	60,339	84,787	69,037
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	18,540
Growth Unit Cost (Net)	2,456	3,003	2,778	2,897	3,779	3,724

55.0 Reference: Exhibit B-1, page C-63, Table 3-4

55.1 Please provide the forecasted values for each item in the referenced table.

<u>Response:</u>

Please refer to Table C3-5 on page C-64 of the Application which provides the forecast values for Sustainment and Other capital. The table has been reproduced below for ease of reference.

Table C3-5: FEI Sustainment and Other Capital Expenditures 2020-2024 ($000s)

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

56.0 Reference: Exhibit B-1, page C-64, Table 3-5

56.1 Please confirm that FEI spending on Sustainment and Other capital has never exceeded $160M prior to 2019.

<u>Response:</u>

Confirmed.

57.0 Reference: Exhibit B-1, page C-64, Table C3-6

57.1 Please explain why FEI Sustainment Capital spending spiked up in 2017 and remained high thereafter.

Response:

As described in the Application on page C-63 and as discussed during the Annual Reviews in the Current PBR Plan term, in years 2014-2016 FEI attempted to manage the pressures being experienced in Growth capital by reprioritizing some Sustainment and Other capital projects that were assessed as having some flexibility in timing to future years. However, as high volumes of customer additions continued to create pressures in Growth capital, it became untenable to continue to offset those costs. This resulted in higher spending levels in 2017-2019 for Sustainment and Other capital relative to 2014-2016. These higher levels are more consistent with the longer-term system requirements.

In 2017-2018, FEI exceeded the formula allowed amount and expects to do so again in 2019. The main reasons for the increased expenditures in these years are:

- Capital expenditures to catch up on an accumulation of work that had been re-prioritized from previous years of the Current PBR Plan term.
- System improvements and new stations to support the added load generated by the higher than expected customer growth that took place during the term of the Current PBR Plan.
- Increased in-line inspection activity to inspect transmission lines that were not previously capable of inspection, and the adoption of additional industry-standard technologies.

Further discussion of Sustainment and Other capital variances can be found in Section 3 of Appendix B8-1.

58.0 Reference: Exhibit B-1, page C-69, Table C3-11

58.1 For each line item (row) in the referenced table, please provide actual yearly expenditures for each year 2014-2018 inclusive and projected for 2019.

Response:

Please refer to the response to BCUC IR 1.47.5.

59.0 Reference: Exhibit B-1, page C-71, Table C3-13

59.1 For each line item (row) in the referenced table, please provide actual yearly expenditures for each year 2014-2018 inclusive and projected for 2019.

<u>Response:</u>

Please refer to the last section of the table provided in the response to BCUC IR 1.47.5.

60.0 Reference: Exhibit B-1, page C-72, Tables C3-14 and C3-15

60.1 Please explain why the Sustainment CIAC forecasted for each year 2020-2024 is less than actual 2018 and forecast 2019.

Response:

CIAC is received for Sustainment capital work where a contribution is received from a customer or a third party that is requesting the work. Typical examples include:

- when a customer requests their service and/or meter to be moved to accommodate remodeling or demolition on the property; or
- when a third party (e.g., a municipality) requests that a gas main be moved due to road widening, sewer or water main construction, or other development.

The CIAC forecast is calculated as a percentage of categories of work that typically attract contributions. Since the work is not initiated by FEI, and FEI typically receives little to no advance warning of the work to be performed, the actual CIAC may be higher or lower than forecast depending on the activity levels for the year, but in the context of the overall capital portfolio, the historical variations in CIAC between years are relatively small.

61.0 Reference: Exhibit B-1, pages A-23 and C-80

61.1 What specific determination is FBC seeking the BCUC to make regarding its capital expenditure forecast (Table C3-21)?

<u>Response:</u>

As stated in Section 2, Approvals Sought of the Application on page A-23, FBC is seeking approval of the level of forecast capital to be incorporated in rates over the term of the Proposed MRP as set out in Table C3-21 in Section C3.4.1.

If, as stated on page C-80, FBC determines in 2022 that it is necessary to update its capital expenditures forecast for 2023-2024, it will file an updated forecast of the 2023 to 2024 expenditures to account for any material changes and ask for approval of the changes at that time.

61.1.1 In particular, is FBC seeking approval for the proposed capital expenditures under section 44.2 of the Utilities Commission Act?

<u>Response:</u>

No. Please refer to the response to BCOAPO IR 1.61.1.

62.0 Reference: Exhibit B-1, pages C-82 to C-83

62.1 Were any of the four transmission growth projects set out in Table C3-23 identified in previous capital plans or long-term energy resources plans filed by FBC?

Response:

All of the four Transmission Growth projects were identified in the 2012 Integrated System Plan (2012 IS) Volume 1, filed by FBC.

These projects were described in Sections 2.8.7, 2.8.8 (pages 109-110); and Sections 2.8.21.3, 2.8.21.7 (pages 122-123).

The following table provides the then-forecast costs in $millions.

Name	2014	2015	2016	2017	2018	2019	2020	2028
Summerland transformer Replacement	$2.15	$4.43						
Beaver Park Substation Upgrade			$0.76	$10.46	$10.31			
Sexsmith 2nd transformer Addition						$3.07	$6.31	
DG Bell 2nd transformer addition								$10.04

62.1.1 If yes, please provide the appropriate references and related cost forecasts.

Response:

Please refer to the response to BCOAPO IR 1.62.1

62.1.2 If not, please explain why.

Response:

Please refer to the response to BCOAPO IR 1.62.1.

62.2 For each of the four transmission growth projects identified in Table C3-23 please describe: i) the alternatives considered and ii) the rationale for selecting the proposed project.

Response:

For each of the four Transmission Growth projects identified in Table C3-23, FBC describes below: i) the alternatives considered and ii) the rationale for selecting the proposed project.

Sexsmith Second Transformer Addition:

i) Prior to the start of project execution in 2019, the alternatives considered were:

1. Addition of a second distribution transformer at Sexsmith substation (chosen alternative)
2. Addition of a second distribution transformer at Ellison substation
3. Addition of a distribution transformer at F.A. Lee substation

ii) The second distribution transformer at Sexsmith was the selected alternative because this station is closest to the load centre. This location provides the most benefit in supplying existing and future load in normal operation and contingency situations.

Summerland Transformer Replacement:

i) Scope definition is on hold pending a decision from the District of Summerland regarding potential future voltage conversion. Detailed analysis of alternatives will be completed once this decision is reached.

ii) Definition and analysis of alternatives is not yet complete.

Beaver Park Substation Upgrade:

i) The alternatives are as follows:

1. Station Rebuild would include replacement of existing transformer, replacement of switchgear, and addition of a second distribution transformer. This is the recommended alternative.
2. Station Rebuild would include replacement of existing transformer and replacement of switchgear. In this alternative, the station would remain a single-transformer substation. This would limit operational flexibility and contingency options.

ii) Alternative 1 is preferred as a second distribution transformer provides additional operational flexibility and improves contingency options.

DG Bell Second Transformer Addition:

i) Analysis of alternatives is ongoing as this project is planned to start in 2024. The alternatives are as follows:

1. Add a second distribution transformer to the DG Bell substation.
2. Construct distribution line upgrades to strengthen ties to other stations and provide improved contingency options. Distribution line upgrades may have the potential to defer the requirement for a second distribution transformer by approximately six years.

ii) Alternative 1 is the preferred alternative as it provides additional operational flexibility and improves contingency options.

63.0 Reference: Exhibit B-1, pages C-83 to C-84

63.1 With respect to Table C3-24, please provide the annual spending on Small Growth Projects and Unplanned Growth Projects for each year 2013-2019.

Response:

The requested information (in thousands) is provided for 2013 to 2019 Projected in the table below.

	2013	2014	2015	2016	2017	2018	2019P
Small Growth Projects	$ 375	$ 1,356	$ 467	$ 29	$ 672	$ 452	$ 132
Unplanned Growth Projects	418	953	608	471	1,123	701	615

63.2 Please explain why the forecast annual spending on Distribution-Small Growth projects over the 2020-2024 period is more than twice the average annual spending in the 2017-2019 period.

Response:

Please refer to the table provided in response to BCOAPO IR 1.63.1. The expenditures in the Current PBR Plan term were reduced from 2015 to 2019 for the projects that were determined to be flexible. The funds from the Small Growth Projects program were reallocated to other programs or projects based on re-prioritization. Forecast expenditures for the 2020 to 2024 period are due to significant load growth in recent years and upgrades that are required to ensure continuing acceptable standards of service.

63.3 With respect to the DG Bell Feeder 4 Addition, please describe: i) the alternatives considered and ii) the rationale for selecting the proposed project.

Response:

The alternatives for the DG Bell Feed 4 Addition project are as follows:

1. Build the distribution feeder along a new road corridor that is being constructed by the City of Kelowna.

2. Build the distribution feeder on a different route utilizing a combination of existing roads and new rights-of-way that would be required to cross private property.

The first alternative was selected as the new road provides a direct route between the substation and the required feeder destination without the requirement for additional land rights and access roads. Additionally, the construction of this new distribution feeder will be coordinated with road construction in order to reduce cost and minimize public inconvenience.

64.0 Reference: Exhibit B-1, pages C-82 and C-84

64.1 With respect to New Connects, please provide the annual spending for each year 2013-2019.

<u>Response:</u>

The requested information (in thousands) is provided for 2013 to 2019 Projected in the table below.

	2013	2014	2015	2016	2017	2018	2019P
New Connects	$ 11,404	$ 15,416	$ 15,938	$ 14,895	$ 17,599	$ 21,906	$ 15,939

65.0 Reference: Exhibit B-1, pages C-85 to C-86

65.1 Please provide a copy of the third party engineering inspection report that identifies the plants where concrete structure rehabilitation is required (page C-85, lines 23-24).

Response:

Please refer to Confidential Attachment 65.1 for the following reports:

1. Lower Bonnington Generating Station – P1 Structural Inspection Report – January 2018
2. P3 –South Slocan – Concrete Condition Assessment –December 2018
3. Corra Linn - Repairs to the Washed Air Chamber Roof – January 2018

FBC requests that Attachment 65.1 be 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. Attachment 65.1 should be kept confidential on the basis that the reports contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

65.2 Please provide a timetable setting out the planned timing for addressing each of these locations and the costs attributable to each (page C-85, line 25-27).

Response:

Please refer to the response to BCUC IR 1.54.3.

66.0 Reference: Exhibit B-1, page C-86

FBC Annual Review for 2019 Rates, Exhibit B-1, page 56

66.1 Please provide the condition assessment report that supports the LBO Spillway Gates Refurbishment Project.

Response:

Please refer to Confidential Attachment 66.1 for a copy of the report, "*Lower Bonnington Dam Sluice Gates Assessment Report*" December 2015.

FBC requests that Attachment 66.1 be 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. Attachment 66.1 should be kept confidential on the basis that it contains sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

66.2 Please explain the difference between the LBO Spillway Gates Refurbishment Project (described at lines 3-8) and the Other Gates Upgrade Project for Lower Bonnington per lines 9-12).

Response:

The LBO (Lower Bonnington) Spillway Gates Refurbishment Project involves the refurbishment of the two spillway gates installed at LBO that are 56 years in age.

The Other Gates Upgrade Project for Lower Bonnington includes capital expenditures in order to be able to close the intake gates under full flow.

The intake gates act as a safety device provided they are in adequate condition and have the capability to close under full water flow conditions. This eliminates or reduces the risk to life safety if the water passage were to fail and of damaging the generating units should control of the units be lost.

66.2.1 Please provide the condition assessment reports that support the Other Gates Upgrade project at Lower Bonnington.

Response:

Please refer to Confidential Attachment 66.2.1 for the Intake Gate Rehabilitation Program Assessment Report.

FBC requests that Attachment 66.2.1 be 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. Attachment 66.2.1 should be kept confidential on the basis that it contains sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

The Intake Gate Rehabilitation Program Assessment Report includes information on non-FBC, non-regulated owned generating facilities. Information on these non-regulated facilities that is contained in the report has been redacted.

66.3 Is the Other Gates Upgrade Project for Upper Bonnington (line 11) part of the UBO Project referenced in the Annual Review for 2019 Rates Application?

Response:

The Other Gates Upgrade Project for Upper Bonnington (line 11) is not part of the UBO Project referenced in the Annual Review for 2019 Rates Application.

The UBO Project referenced in the Annual Review for 2019 Rates Application was approved by Order G-8-17 and involves the refurbishment of generating Units 1-4 (the Old Units), which are more than 100 years old, in order to extend their lives for an additional twenty years or more. The project will also reduce the safety and environmental risks associated with failures of the aged equipment.

The Other Gates Upgrade Project for Upper Bonnington includes the following small projects:

- Upgrade of Upper Bonnington Unit 6 hoist;
- Refurbishment of Upper Bonnington Spillway Gates; and
- Replacement of Upper Bonnington intake and sluice gates hoist access ladders for compliance with WorkSafe BC regulations.

66.3.1 If not, please explain the difference/relationship between the projects.

Response:

Please refer to the response to BCOAPO 1.66.3.

66.3.2 If not, please provide the condition assessment reports that support the Other Gates Upgrade project at Upper Bonnington.

Response:

Please refer to Confidential Attachment 66.3.2 for the following condition assessment reports:

- Upper Bonnington Dam Safety Review
- Upper Bonnington Head and Sluice Gate Superstructure Structural Inspection Report (2018)

FBC requests that Attachment 66.3.2 be 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. Attachment 66.3.2 should be kept confidential on the basis that they contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

66.4 Is the Other Gates Upgrade Project for Corra Linn (line 11) part of the UBO Project referenced in the Annual Review for 2019 Rates Application?

Response:

The Other Gates Upgrade Project for Corra Linn (line 11) is not part of the UBO Project referenced in the Annual Review for 2019 Rates Application. Please refer to the response to BCOAPO IR 1.66.3 for a description.

The Other Gates Upgrade Project for Corra Linn (line 11) is also not part of the Corra Linn Project referenced in the Annual Review for 2019 Rates Application, the Corra Linn Dam Spillway Gates Replacement Project.

The Corra Linn Dam Spillway Gate Replacement Project referenced in the Annual Review for 2019 Rates Application was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure.

The Other Gates Upgrade Project for Corra Linn includes the following small projects:

- Replacement of Corra Linn intake gates hoist access ladders for compliance with WorkSafeBC; and
- Refurbishment of Corra Linn tailrace gates.

66.4.1 If not, please explain the difference/relationship between the projects.

Response:

Please refer to the response to BCOAPO IR 1.66.4.

66.4.2 If not, please provide the condition assessment reports that support the Other Gates Upgrade project at Corra Linn.

Response:

Please refer to Confidential Attachment 66.4.2 for the following condition assessment reports:

- Corra Linn Head Gates Superstructure Structural Inspection Report (2018)
- Corra Linn Dam – Tailrace Gate Single Device Isolation Certification (2015)

FBC requests that Attachment 66.4.2 be 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. Attachment 66.4.2 should be kept confidential on the basis that they contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

66.5 Please provide the condition assessment reports that support the Other Gates Upgrade Project at South Slocan.

Response:

Please refer to Confidential Attachment 66.5 for the following reports:

- South Slocan - SDI Device Report
- South Slocan head gates superstructure structural inspection report

FBC requests that Attachment 66.5 be 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. Attachment 66.5 should be kept confidential on the basis that they contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

The Other Gates Upgrade Project is also supported by the Intake Gate Rehabilitation Program Assessment, a redacted version of which is included in Confidential Attachment 66.2.1 provided in response to BCOAPO IR 1.66.2.1.

67.0 Reference: Exhibit B-1, page C-86 (lines 21-27)

67.1 When were the "current" OHS requirements requiring guards and covers for rotating and moving parts put in place?

Response:

The OHS requirements for guards (Parts 12.2, 12.3 and 12.16) have been in regulation since 2003. In 2013, FBC became aware that the original guarding installed at a number of FBC plants was not compliant with the regulation. FBC developed a plan to address the noncompliance of the guarding on a prioritized basis. The high priority items identified were the turbine shaft and wicket gate linkages, which were not guarded.

67.1.1 If prior to 2018, how much has FBC spent annually to meet these new requirements since they were introduced?

Response:

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. In 2013, FBC received a WorkSafe BC order to address the missing 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 capital expenditures incurred under the Current PBR Plan associated with installing the guards on rotating parts are shown in the table below.

Installing Guards on Rotating Equipment ($000s)

2014	2015	2016	2017	2018	2019P
$ -	$ -	$ 137	$ 111	$ 111	$ 168

68.0 Reference: Exhibit B-1, page C-87

68.1 Please provide copies of any assessment reports supporting the end-of-life/obsolescence of the generating equipment/assets being replaced per lines 3-20.

Response:

Please refer to Attachment 68.1 for the UBO Unit 6 Runner Inspection Report.

69.0 Reference: Exhibit B-1, page C-88

69.1 With respect to Table C3-30, please explain the significant increase in the spending in 2022 on Other Buildings and Structures Projects.

<u>Response:</u>

The Other Buildings and Structures Project includes a variety of small projects related to security signage and fencing, windows, roads, cover screens, access ladders, guarding of rotating parts and fire panels.

The increase in spending in 2022 on Other Buildings and Structures Project is mainly related to the following one-time projects:

- Corra Linn Powerhouse Window Replacement Project - $0.265 million
- LBO Generating Station Lower Access Road Upgrade – $0.073 million
- LBO Tailrace Vent Cover Screens Upgrade – $0.167 million
- UBO Airwash Intake Screens Upgrade – $0.041 million

70.0 Reference: Exhibit B-1, page C-89

70.1 Please provide the annual spending on Transmission Line Condition Assessments for each of the years 2013-2018.

<u>Response:</u>

The requested information (in thousands) is provided for 2013 to 2019 Projected in the table below.

	2013	2014	2015	2016	2017	2018	2019P
Transmission Line Condition Assessement	$ 412	$ 526	$ 389	$ 487	$ 468	$ 467	$ 725

70.2 Please provide the annual spending on Other Transmission Line Rehabilitation for each of the years 2013-2018.

<u>Response:</u>

The requested information (in thousands) is provided for 2013 to 2019 Projected in the table below.

	2013	2014	2015	2016	2017	2018	2019P
Other Transmission Line Rehabilitation	$ 1,079	$ 3,473	$ 4,907	$ 3,743	$ 2,865	$ 3,052	$ 2,141

70.3 Has the 2019 Transmission Line Condition Assessment been completed?

<u>Response:</u>

No. The 2019 Transmission Line Condition Assessment is expected to be completed by the end of September 2019.

70.3.1 If yes, please indicate how the findings support a level of spending on Other Transmission Line Rehabilitation that is almost 83% higher than the average annual spending in 2017-2019.

Response:

Please refer to the response to BCOAPO IR 1.70.3.

70.3.2 If not, please explain the basis for the 83% increase in forecast spending on Other Transmission Line Rehabilitation over historical levels.

Response:

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 cannot 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 have been included to replace insulators.

The 83 percent represents the increase between 2020 and the average (2017 – 2019) for the Other Transmission Line Rehabilitation. In 2020, the increase relates to the higher number of poles in the transmission lines that are going to be rehabilitated and the replacement of the insulators.

70.4 Given that the transmission line condition assessments that will identify the rehabilitation work that will be required in 2021 to 2024 have not yet been completed, please explain the material variation in annual spending on Other Transmission Line Rehabilitation over this period (per Table C3-32).

Response:

Please refer to the response to BCOAPO IR 1.70.3.2.

71.0 Reference: Exhibit B-1, pages C-47 and C-90

71.1 Is any of the planned capital spending on Transmission Right of Ways (per Table C3-33) related to addressing the ROW boundary issue noted at page C-47 with respect to the Kootenay area? If not, why not?

Response:

Yes. The 30L, 32L and 19L Rights of Way Improvements in the Kootenay area are described on page C-90 of the Application.

71.2 What percentage of FBC's total km of transmission lines are accounted for by 30 Line, 32 Line and 19 Line respectively?

Response:

The total length of FBC-owned Transmission lines is 1,289.4 km. The total length of 19L, 30L & 32L is 172.4 km, accounting for 13.4 percent of the total length of FBC-owned Transmission lines.

72.0 Reference: Exhibit B-1, pages C-91 and C-92

72.1 Please provide the condition assessments that support the planned transformer replacements set out in Table C3-35.

Response:

Please refer to Confidential Attachment 72.1.

FBC requests that Attachment 72.1 be 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. Attachment 72.1 should be kept confidential on the basis that they contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

73.0 Reference: Exhibit B-1, page C-92

73.1 Please clarify the scope of the Salmo Station Upgrade. Does it include both the replacement of the existing transformer and the installation of a second transformer?

Response:

Yes, the scope of the Salmo Station Upgrade includes both the replacement of the existing transformer and the installation of a second transformer.

The Salmo Station Upgrade project proposes to increase capacity and rebuild the Salmo substation on the existing station footprint while decommissioning the legacy Ymir substation. The project is necessary to meet load growth and to continue to reliably supply electricity to the area. It will also address aging infrastructure, condition of equipment, single contingency reliability, and mitigate flood risk for the area.

73.2 Please provide the condition assessments that support: i) the decommissioning of the Ymir substation and ii) the replacement of the existing transformer at the Salmo substation.

Response:

Please refer to Confidential Attachment 73.2.

FBC requests that Attachment 73.2 be 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. Attachment 73.2 should be kept confidential on the basis that they contain sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

73.3 What is the timing for the decommissioning of the Ymir substation?

Response:

The Ymir substation decommissioning is planned for 2021.

73.4 What is the current capacity of the existing Salmo transformer and the current peak load on the Salmo substation?

Response:

The current capacity of the existing Salmo transformer is 15 MVA and the current winter peak load is 6.9 MW in 2018.

73.5 What is the additional load that will be transferred to the Salmo substation when the Ymir substation is decommissioned?

Response:

The additional load that will be transferred to the Salmo substation is the forecast winter peak load for 2021, which is 2.6 MVA.

73.6 What alternatives were considered to the current plan of decommissioning the Ymir substation and adding a second transformer at the Salmo substation?

Response:

There were three other alternatives that were considered for the Salmo Station Upgrade project. The alternatives are described below.

1. Decommission Ymir and add a single 20 MVA transformer at Salmo station, transferring Ymir load to Salmo station.

2. Decommission Ymir and add two 20 MVA transformers at Salmo station, transferring Ymir load to Cottonwood station.
3. Decommission Ymir and add a single 20 MVA transformer at Salmo station, transferring Ymir load to Cottonwood station.

The recommended alternative is to decommission Ymir and add two 20 MVA transformers at Salmo station, transferring Ymir load to Salmo. A 20 MVA transformer is the smallest standard size currently installed by FBC.

When evaluating the alternatives, the recommended option to transfer Ymir load to Salmo station instead of Cottonwood station was selected due to cost and the ability to maintain the supply. To supply Ymir from Cottonwood, a new three phase 16 kilometer distribution extension would need to be constructed from Cottonwood station to Ymir station because the existing system cannot currently be configured to offload either station to the other. Under the proposed route, approximately 5 kilometers of the line extension would be built on 27L underbuild through dense forest, making it very difficult to access and maintain. The Class 5 cost estimate for the Cottonwood option was also triple the Salmo option due both to the complexity and length of the extension. For these reasons, transferring Ymir load to Cottonwood was not selected.

When evaluating the alternatives, the recommended option to install two 20 MVA transformers at Salmo station was selected because it provides single contingency distribution reliability and sufficient capacity for the area over the expected life span of the new transformers. Given the existing system, due to limited offload capability in the Salmo area, in the event of a Salmo T1 transformer outage under peak load conditions, only 16 percent of all Salmo customers can be supplied. By installing a second transformer, no customer outages would be required during a Salmo transformer outage. Additionally, with the decommissioning of Ymir, the capacity of the single transformer at Salmo station (15 MVA) will be insufficient to support both the Ymir load and recent new large capacity requests in the area. The 20-year load forecast indicates the area will require 18 MVA in 2038. If only a single 20 MVA transformer is installed, capacity at Salmo will likely need to be increased within the lifespan of the transformer. Although this option has the highest capital cost, it will improve reliability for customers in the Salmo area and provide sufficient capacity for growth over the lifespan of the new transformers.

73.6.1 Why were they rejected in favour of the proposed Project?

Response:

Please refer to the response to BCOAPO IR 1.73.6.

74.0 Reference: Exhibit B-1, page C-93

74.1 Please provide the condition assessment of the generator step-up stations on the Kootenay River hydro plants that supports the proposed 2020 spending of over $1 M and document the specific work planned as a result.

Response:

Please refer to Confidential Attachment 74.1.

FBC requests that Attachment 74.1 be 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. Attachment 74.1 should be kept confidential on the basis that it contains sensitive technical information pertaining to FBC's assets. FBC reasonably expects that the release of this information may jeopardize the safety and security of FBC's assets.

The scope of work for the generator step-up stations is described on page C-93 of the Application. The areas of the stations that will be repaired are station connecting lines, ground grids, and metal, wood, and concrete structures. Based on the condition assessment of the generator step-up stations, the work to be performed will address the replacement of air-to-air bushings, concrete and metal structures repairs, transformer life extension and oil leak mitigation.

75.0 Reference: Exhibit B-1, page C-94

75.1 What are the locations of the planned Ground Grid Upgrades for 2022 and 2024 and what are the specific deficiencies that will be addressed at each location?

Response:

In 2022, Condition Assessments will be performed at the following locations: AS Mawdsley (ASM), Coffee Creek (COF), Cottonwood (COT), Crawford Bay (CRA), Creston (CRE), Kaslo (KAS), Kettle Valley (KET), Nk'Mip (NKM), Pine Street (PIN), Princeton (PRI), Rosemount (RSM), and Waterford (WAT).

In 2024, grounding study reviews and grounding inspections with bonding checks will be performed at the following locations: Arawana (AWA), Black Mountain (BLK), Big White (BWS), Ellison (ELL), Midway (MDY), Okanagan Falls (OKF), Okanagan Mission (OKM), and Ootischenia (OOT).

Based on the condition assessment and the grounding study reviews, specific deficiencies will be addressed at the above locations if needed.

Other deficiencies to be addressed are:

1. RG Anderson (RGA), Sexsmith (SEX), Keremeos (KER), Cascade (CSC) -Top up of the insulating gravel;
2. Summerland (SUM) – Installation of insulating panels to limit the transfer of potential to the City of Summerland owned yard;
3. Grand Forks Terminal (GFT) – Installation of the grounding wells; and
4. Warfield Terminal (WTS) - Emerald Switching Station (ESS) (third-party owned) and WTS (FBC owned) ground grids should be interconnected. A grounding study review will be completed for WTS and if required the design and construction of the overhead connection between ESS and WTS will be initiated.

76.0 Reference: Exhibit B-1, page C-94

76.1 What is FBC's replacement strategy with respect to MOCBs (i.e., are they replaced upon failure, is replacement based on condition assessment, or is there some other approach)?

Response:

FBC's replacement strategy for Minimum Oil Circuit Breakers is planned and prioritized on the basis of outdated/unmaintainable technology, their increase in financial and technical resource consumption, employee and public safety due to risk of failure, environmental hazards, impact on system reliability and revenue loss. FBC has a remaining fleet of 30 Minimum Oil Circuit Breakers and expects to replace a maximum of 3 units annually.

76.2 How many MOCBs are in FBC's "fleet" and how many will the proposed expenditures replace annually?

Response:

Please refer to the response to BCOAPO IR 1.76.1.

77.0 Reference: Exhibit B-1, pages C-94 to C-95

77.1 What are the reasons for the higher levels of spending Other Station Equipment in 2021 and 2022 (as compared to historical and post-2022 spending levels per Table C3-36)?

<u>Response:</u>

Other Station Equipment proposed spending includes the following projects in 2021 and 2022:

- Outdoor isolating switch replacement as described on page C-95 of the Application.
- The DG Bell 138 kV breaker and Voltage transformer addition which will improve and simplify the protection scheme at the terminal station and increase operational reliability in the Kelowna Area.

The table below provides the expenditures per year (in $thousands) for each of the above projects:

	2021	2022
Outdoor Isolating Switch Replacement	$ 543	$ 548
DG Bell 138 kV Breaker and Voltage Transformer Addition	$ 801	

78.0 Reference: Exhibit B-1, page C-97

78.1 Please provide the number of porcelain cutout failures in each year over the period 2013-2018.

Response:

The following table provides the recorded number of porcelain cutout failures in each year over the period 2013 – 2018.

Year	Failures
2013	27
2014	37
2015	23
2016	45
2017	79
2018	62

79.0 Reference: Exhibit B-1, page C-99

79.1 Please explain why the projected annual spending on SCADA Systems Sustainment is materially higher than historic annual levels.

<u>Response:</u>

The SCADA Systems Sustainment portfolio includes MRS related sustainment expenditures which includes infrastructure replacement costs every 5 years similar to other systems in FortisBC's infrastructure. Starting in 2020, ongoing sustainment capital costs arising from MRS Assessment Reports 8 and 10 are included in this portfolio and are provided in the response to BCUC IR 1.36.5.

The remainder of the difference encompasses efforts for other hardware and software systems as a result of delayed expenditures in previous years.

80.0 Reference: Exhibit B-1, pages C-82 and C-105 to C-106

80.1 Are the Contributions in Aid of Construction ("CIAC") for New Connects (per Table C3-42) all associated with the New Connects spending set out in Table C3-22?

Response:

Yes. The Contributions in Aid of Construction for New Connects in Table C3-42 are all associated with the New Connect forecast spending set out in Table C3-22.

80.1.1 If not, please provide a schedule setting out any additional capital spending associated with the CIAC for New Connects shown in Table C3-42 and indicate where this spending is incorporated in Section C3 of the Application.

Response:

Please refer to the response to BCOAPO IR 1.80.1.

80.2 Please indicate what category/categories of capital spending in Section C3 given rise to the CIAC related to Forced Upgrades (per Table C3-42) and indicate the gross amount of capital spending on Forced Upgrades for each year 2017-2024.

Response:

Only Forced Upgrades Capital expenditures result in CIAC related to Forced Upgrades. The gross amount of capital spending on Forced Upgrades for 2017-2024 is in the table below (in millions).

	2017	2018	2019	2020	2021	2022	2023	2024
Force Upgrades and Line Moves	\$2.323	\$2.348	\$2.120	\$2.578	\$2.564	\$2.656	\$2.570	\$2.758

81.0 Reference: Exhibit B-1, pages C-109 to C-110 and pages C-165 to C-167

FBC's Annual Review for 2019 Rates, Exhibit B-1, pages 35-37

81.1 Please provide a schedule that sets out for each year 2014-2019 the reduction that was incorporated in the forecast Power Purchase Expense used to determine rates in order to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases (similar to the $2 M incorporated for 2019 rates per page 37)

Response:

The table below shows the annual reduction that FBC incorporated in each forecast Power Purchase Expense to account for potential real-time market opportunities.

	2014	2015	2016	2017	2018	2019
Market Adjustment (million)	-$2.0	-$1.0	-$1.0	-$2.0	-$2.0	-$2.0

81.2 Please provide a schedule that sets out for each year 2014-2018 the actual net reduction in Power Purchase Expense (relative to forecast) as a result real-time opportunities to displace PPA purchases with lower cost market purchases.

Response:

Please refer to the response to BCUC IR 1.102.1.1 that shows the Incremental Mitigation for all mitigation activities. FBC is not able to break out only the real-time (within the day) opportunities without a significant level of effort.

81.3 Under FBC's proposed MRP will the forecast Power Purchase Expense used for setting rates include any reductions to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases?

Response:

Consistent with past practice, FBC will provide reductions to PPE to account for potential additional opportunities to displace PPA purchases to the extent that FBC expects the savings will be achieved. FBC will continue to forecast PPE using the best information available at the time, including a reasonable forecast of future market opportunities. The proposed PSI calculation is not linked to any forecast of PPE, rather it is based on a calculation of actual benefits achieved after the fact. FBC will continue to forecast PPE with the goal of minimizing the variance between forecast and actual.

82.0 Reference: Exhibit B-1, pages C-111 to C-113

In Section 4.4.2, FortisBC discusses investment in a Green Future.

82.1 Please confirm that for each item in Section 4.4.2, FortisBC will include all changes in revenues, as well as costs in as treatment outside of indexed costs.

Response:

Confirmed.

82.2 Please fully explain why investments such as NGT Fueling Stations, LNG Production costs or EV Charging stations should be funded through rates to customers, and not proposed on a standalone basis, where the costs are not included in FBC or FEI rates, and only paid for via revenues for providing the service.

Response:

Each of the three type types of investments mentioned in the question represent public utility activities under the *Utilities Commission Act* and provide (or have the potential to provide) benefits to other utility ratepayers, which include the recovery of revenues from the specific NGT or Electric Vehicles (EV) charging station customers and Rate Schedule (RS) 46 that reduce the revenue requirement for all customers.

In addition to NGT service from utility-owned stations being a public utility service under the UCA, the BC government has confirmed the appropriateness of passing on net benefits of NGT station service to gas ratepayers, or recovering the net costs, by establishing prescribed undertakings in the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) for utilities to own and operate either compressed natural gas (CNG) or LNG stations (or both). Further, by Direction No. 5 to the BCUC, the BC government has stipulated that utility-owned CNG and LNG stations are not to be tracked separately but rather are to be part of the overall natural gas utility rate base. However, the rates charged for service at utility-owned CNG and LNG stations are typically designed to be adequate to recover station costs and potentially to provide net benefits to other ratepayers.

With regard to LNG production costs, FEI's LNG facilities at Tilbury Island in Delta and Mt Hayes near Ladysmith on Vancouver Island provide very valuable service to all of FEI's non-bypass customers as peak shaving facilities to meet customer demands for natural gas in cold and very cold winter conditions, or as emergency backup supply at other times of the year. This valuable service has been supplied from the Tilbury Island facility since the 1970s and from the Mt Hayes facility since 2011. These LNG facilities have been in FEI's or predecessor utilities' rate base since they began operations. More recently LNG service has been provided under RS 46 to serve transportation markets, particularly in the trucking and marine sectors. The RS 46 rate structure includes components that represent a reasonable recovery of the LNG facility and production costs for RS 46 customer volumes, but also that both LNG facilities provide significant benefits to all of FEI's customers.

Electric Vehicle (EV) charging service is the subject of a BCUC inquiry, currently awaiting the BCUC's report and recommendations from the second phase of the proceeding. In the first phase of the EV Charging Service Inquiry the BCUC concluded that, when provided by parties other than those excluded from the UCA public utility definition (such as municipalities), public EV charging service is public utility activity. In Phase One, the BCUC also recommended that an exemption from active regulation be established for EV charging service providers other than the incumbent utilities[8]. For incumbent public utilities, the BCUC's recommendations for treatment of utility-owned EV charging facilities and EV charging service will be in the Phase 2 report. However, in its procedural order setting out the final scope and timetable for Phase 2 of the Inquiry the BCUC acknowledged the BC government's policy intentions in support of public utility participation in EV Charging Service as follows:

> Panel Determination
>
> The BC government stated it "strongly supports investments in electric vehicle charging services by those non-exempt public utilities" and argued "it would be appropriate for non-exempt public utilities to recover those costs from ratepayers." Many interveners support this view and those that don't express support nonetheless accept that participation in light of the government's stated position but argue that the scope of the non-exempt public utility involvement is still an issue in this Inquiry.
>
> **The Panel accepts that there is a role for non-exempt utilities in providing public EV charging services. To reflect this public policy objective the Panel finds it appropriate to narrow the scope for Phase 2 of the Inquiry to addressing the manner in which they should participate.**[9]

In view of the foregoing, FortisBC expects some degree of incumbent utility participation in the provision of EV charging service to be the result, but the nature and extent of that participation is still to be determined. FortisBC has proposed to design rates for its own EV charging service

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8 The recommended exemption was later approved, after receipt of a ministerial order, by BCUC Order G-66-19.
9 BCUC Order G-50-19, Appendix A, page 4.

that reflect reasonable cost recovery and that have the potential to provide net benefits to other ratepayers.

82.3 Please fully explain how each of the proposed initiatives are <u>required</u> to provide safe and reliable utility service to residential, commercial, or industrial customers of FEI or FBC.

<u>Response:</u>

Safe and reliable utility service to residential, commercial and industrial customers is the fundamental starting point of FortisBC's service to its gas and electric customers and this will continue to be the case into the future. As noted in the response to BCOAPO IR 1.82.2, the service already being provided by FEI's LNG facilities plays a critical role in ensuring safe and reliable service to FEI's customers.

Section C4.4.2 of the Application referenced in the question deals with particular O&M categories pertaining to the "Clean Growth Future" that FortisBC believes are appropriate to exclude from the index-based O&M in the MRPs. The full rationale for preparing for the Clean Growth Future is set out in Section B1 of the Application, especially in Section B1.2 dealing with environmental policy and FortisBC's response. FortisBC believes that being proactive in its plans and actions to prepare for a lower carbon future is in the best interests of both its customers and the long term health of the Utilities. Preparing actively to address evolving government policy and customer expectations will enable the Utilities to provide valuable energy services to all of its customers that are "clean" and cost-effective, as well as safe and reliable, long into the future. In addition, new "clean" initiatives such as NGT that generate incremental throughput and sources of revenue, can help to offset future rate pressure from declining system throughput.

83.0 Reference: Exhibit B-1, pages C-115 & C-116

In section 4.10 FortisBC discusses exogenous factors.

83.1 Please confirm that a decision by a parent company is not an exogenous factor. If not confirmed, please fully explain.

<u>Response:</u>

Confirmed. Please refer to Section C4.10 of the Application for examples of factors that would qualify for exogenous factor treatment.

83.2 Please fully explain how a decision of the BCUC, that is related to a FBC or FEI application is an exogenous adjustment.

<u>Response:</u>

BCUC decisions in other proceedings would qualify for exogenous factor treatment if they change the determination of revenue requirements by allowing or disallowing costs or expenditures or if they change the manner in which the costs are to be recovered. The examples provided in Section C4.10 include such things as the outcomes of rate design applications, which would need to be reflected in revenue forecasts, depreciation studies, which impact depreciation expense, and cost of capital proceedings, which determine the utility's ROE. Such decisions are not within the control of the Utilities and therefore qualify as exogenous factors.

84.0 Reference Exhibit B-1, page C-120

84.1 Do FBC's BCUC Levies include BCUC costs attributable to specific FBC proceedings?

Response:

No. The BCUC Levies are set annually to recover the BCUC's forecast operational budget and initiatives for its upcoming fiscal year. In setting the Levies, the BCUC reviews the current year's under-recovery or over-recovery compared to year-to-date actuals and then sets the Levy amounts apportioned to each regulated utility based its prior year's energy sales. The BCUC Levies do not include costs attributable to specific utility proceedings. The BCUC issues direct cost invoices for specific utility proceedings to the utility in order to directly recover Commissioner, contractor, and consultant fees and expenses incurred.

84.1.1 If yes, why is it reasonable to recover over one-year BCUC levies associated with proceedings that deal with multi-year issues (e.g. COSA & RDA proceedings, LTERP proceedings, etc.)?

Response:

Please refer to the response to BCOAPO IR 1.84.1.

85.0 Reference: Exhibit B-1, pages C-128 to C-146

In Section 6 FortisBC discusses its clean growth innovation fund.

85.1 Please confirm that the main purpose of the fund is to assist FBC and FEI in meeting its obligations and expectations to minimize environmental impacts.

<u>Response:</u>

As stated in Exhibit B-1 page A-12, "… the Companies are proposing the creation of a Clean Growth Innovation Fund to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for our customers. The Clean Growth Innovation Fund will assist FortisBC in addressing the expectation to reduce emissions and support the transition to a lower carbon economy while maximizing the use of its energy delivery systems for the benefit of its customers."

85.2 On page C-128, FortisBC discusses how it believes it should have a role to play in clean energy. Please fully explain why the costs of such a fund should not be paid by the utility shareholder.

<u>Response:</u>

The goals of the Clean Growth Innovation Fund are described on page C-128: "… 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." These goals directly benefit FortisBC customers and British Columbians in general. The goals do not directly benefit the utility shareholder.

It is in the best interest of customers, the Utilities and society 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.

For these reasons, FortisBC believes it is appropriate for the costs to be paid by ratepayers.

Please also refer to the response to BCUC IR 1.81.1.

85.3 Please confirm that any innovations, or other improvements or intellectual property developed or funded through the proposed fund will belong to the customers of FEI and FBC, and all future benefits or future revenues will flow through to the benefit of future customers. If not confirmed, please fully explain.

Response:

FortisBC expects to provide grant funding to assist in accelerating the commercialization of clean innovations. It does not intend to take an equity position in any related companies or own any intellectual property developed in the partnerships.

Customers and British Columbians in general will benefit from commercial innovations as a result of the proposed fund which are expected to provide customers with clean, cost-effective energy solutions. Please also refer to the response to BCOAPO IR 1.96.4.

85.4 In Sections 6.3.1, 6.3.2, and 6.3.3 FortisBC discusses three case studies. Please provide a complete list of projects that FortisBC is aware of that have not resulted in tangible benefits.

Response:

FortisBC's research was not focussed on reviewing the tangible benefits of individual projects. The evaluation of innovation funding should consider the broader context as it is expected that some projects will succeed while others will not. Appendix C6-1 of the Application (page 33) provides additional context on this issue:

> The history of utility customer-funded innovation funding is relatively recent, so data on the benefits of these programs can be difficult to quantify. Successful deployment requires regulatory flexibility and appropriate governance to ensure the trade-offs between costs and impacts on rates are justified. Given the global nature of these policy objectives, the opportunity exists for lessons learned to be shared among regulators and industry stakeholders.

While not all demonstration projects successfully prove out a new technology or business model, these investments frequently prove to be gateways to new utility models, short-term accelerators to competitive service offerings, or some combination of quantitative and qualitative benefits. The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits of customer-funded innovation justify the costs.

85.5 Please provide a complete list of innovative technologies that FBC or FEI, or FortisBC, has developed and implemented, that were commercially successful.

Response:

Please see below a list of the clean technology companies that are undertaking a de-risking project with Natural Gas Innovation Fund (NGIF) to get them closer to commercialization and an end-use applicability to BC.

Project Proponent	Technology	Funding Round	Level of Completion	TRL (Technology Readiness Level)	Year of Technological Commercialization
Hydrogenics Corporation	Power to gas. Hydrogen pipe injection.	0	14%	6	2020
iGEN Technologies Inc.	Hybrid (electric/gas) smart furnace w blackstart.	0	100%	4	2021
G4 Insights Inc.	Wood biommas RNG	0	79%	6	2022
Enersion Inc.	Heat (adsorption) cooling.	1	44%	5	2020
Westport Fuel Systems	Conformable CNG tank.	1	0%	3	2022
NextGrid Inc.	Residential micro CHP	1	25%	3	2020
Harvest Systems	kitchen waste energy recovery system.	2	0%	5	2024
iGEN Technologies Inc.	Hybrid furnace demonstration.	2	0%	6	2021
Effect Home Builders Ltd.	Micro CHP, waste heat capture.	2	75%	7	2020
Stone Mountain Technologies Inc.	Hybrid gas electric heat pump.	2	0%	3	2020
Quadrogen Power Systems Inc.	Landfil gas clean up and upgrading.	2	40%	6	2020
Ekona Power Inc.	Low cost hydrogen production.	3	0%	4	2022
True Energy Incorporated	hydrogen conversion of sewage sludge into RNG.	3	0%	4	2021
University of Toronto	RNG through electrocatalytic CO2 conversion.	3	0%	3	2025

In addition to NGIF projects, FEI provides the following examples:

- FEI is piloting a commercial carbon capture technology from Clean O_2 that scrubs CO_2 from the flue stack of commercial boilers, thus reducing end-use emissions.
- FEI has successfully piloted commercial heating products such as a residential wall furnace designed to heat smaller homes as well as residential "combi" (gas water heating and space heating combination systems). Please refer to the response to BCUC IR 1.30.19 and 1.30.21.
- FEI successfully developed an "on ship" LNG bunkering technology to re-fuel ferries (FEI owns this technology); this technology is already in commercial operation.

Additionally, there are several other DSM Innovative technologies that are at the commercial stage. More information on these initiatives is in FEI's annual Conservation and Energy Management Report, and in the response to BCUC IR 1.73.7 and Attachment 73.7.

86.0 Reference: Exhibit B-1, pages C-147 to C-154

In section 7, FortisBC discusses Service Quality Indices.

86.1 In Table C7-1, FortisBC provides SQIs for FEI. Please fully explain why inspection activities, and other monitoring activities are not included as SQIs. In the response please fully explain.

Response:

FortisBC describes its general approach to its proposals for SQIs in the response to BCUC IR 1.84.1.

The proposed FEI SQIs represent a continuation of the existing suite of approved SQIs, which the BCUC determined in the 2014 PBR Decision represented a balanced set of indicators that collectively addressed reliability, safety and customer needs. In its review of existing SQIs for possible changes, FortisBC concluded the existing suite of SQIs continue to remain appropriate, subject to the proposed amendments to the benchmarks/thresholds and addition/replacement of some of the SQIs. FortisBC believes the current suite of SQIs have been appropriate and useful in monitoring the Utilities' performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality.

FEI is unclear of what is meant in the question by "inspection activities, and other monitoring activities" as SQIs and has assumed this refers to the use of leading indicators as SQIs. Leading indicators, such as inspection and monitoring, can help influence the outcome of an event. For example, regarding employee safety, as discussed in the response to BCUC IR 1.84.6, FortisBC is looking into introducing other indicators of safety performance in the form of 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 (i.e., inspection) indicators is required.

However, for the purpose of the SQIs used in the proposed MRPs to measure overall service quality levels to determine whether a degradation of service quality has occurred, FEI believes the focus should remain on SQIs that measure results (i.e., lagging indicators) which are representative of the service quality levels to customers. Leading indicator SQIs may be used by FortisBC to assist in the management of the performance of SQIs without forming part of the suite of SQIs used to report on service quality levels during the proposed MRP term.

86.2 For each SQI with benchmarks and thresholds, please fully explain the penalty or consequence for failing to meet the stated benchmark or threshold.

Response:

Please refer to the response to BCUC IR 1.90.8 for discussion of the proposed process for examining the performance of SQIs and the implications under the proposed MRPs. The proposed process is the same as the process being used for the Current PBR Plans.

87.0 Reference: Exhibit B-1, page C-150

87.1 Would it be possible for FEI to retain the Telephone Abandonment Rate while adding the Average Speed of Answer SQI?

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.88.6 and 1.88.6.1.

88.0 Reference: Exhibit B-1, page C-151

88.1 For each of the following SQIs in Table C7-5 (i.e., those with a Proposed Benchmark and a Proposed Threshold where no historical data has been provided in the Application), please set out the actual annual values for each year 2014-2018:

- Emergency Response Time
- All Injury Frequency Rate
- First Contact Resolution
- Telephone Service Factor

<u>Response:</u>

Please refer to the response to BCUC IR 1.90.7 which provides a table for FBC showing the historical performance and benchmark and threshold levels during the Current PBR Plan term for each SQI with a benchmark/threshold and the historical performance for the informational indicators.

FBC notes that historical data including annual performance and the approved benchmark and threshold for each of the proposed SQI has been included in Appendix C5-1 FEI SQI Report and Appendix C5-2 FBC SQI Report.

88.2 Please explain why, for the two Safety SQIs and the Telephone Service Factor SQI, FBC has proposed no changes to either the Benchmark or the Threshold values.

<u>Response:</u>

For Emergency Response time, FBC has not proposed changes to the Benchmark and Threshold as the performance during the Current PBR Plan was approximately 93 percent and consistent with the existing benchmark of 93 percent. FBC believes the current benchmark represents the level of service expected by its customers and is appropriate. FBC therefore proposes to retain its existing benchmark and threshold for the term of the proposed MRP.

For more information, please refer to page 5 of Appendix C5-2 FBC SQI report.

For the All Injury Frequency Rate (AIFR), FBC believes that the current benchmark remains appropriate as the Company assesses the trend. Safety results should be monitored and reviewed on a longer term and trend basis before the existing benchmark is adjusted to reflect recent historical performance.

For more information, please refer to page 7 of Appendix C5-2 FBC SQI report.

For the Telephone Service Factor, the results from 2014 to 2018 were consistent with the benchmark of 70 percent except for 2014 which was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers. FBC proposes to retain the existing benchmark and threshold.

For more information, please refer to page 10 of Appendix C5-2 FBC SQI report.

89.0 Reference: Exhibit B-1, pages C-151 to C-152

89.1 Please explain why, based on past performance, 74% is now proposed as the Threshold value for the First Contact Resolution SQI?

Response:

In increasing the FBC threshold from 72 percent to the proposed 74 percent, FBC is aligning the threshold more closely to past performance. The performance from 2014 to 2018 has been consistently better than the threshold with performance trending upwards over the years.

Please refer to the table below (Excerpt from page 7 of Appendix C5-2 FBC SQI Report) which provides the results of the First Contact Resolution SQI from 2014-2018.

18 **Table A:C5-2-6: Results during the PBR Plan for First Contact Resolution**

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
First Contact Resolution	73%	76%	79%	80%	82%	78%	78%	72%	74%

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89.2 Why has FBC not proposed an increase in the Benchmark value for the First Contact Resolution SQI?

Response:

Similar to the proposed First Contact Resolution (FCR) benchmark for FEI, the current FCR benchmark was 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 was 71 percent). Recent industry average for call centre performance (i.e., 2018 was 70 percent) remains consistent with the 2012 comparator. As a result, the existing benchmark of 78 percent remains appropriate for FBC as its performance remains above the industry average for call centre performance.

90.0 Reference: Exhibit B-1, pages C-152

90.1 Given that the recent Billing Index SQI values have all been less than one, why is FBC proposing that the Benchmark value only be reduced to 3.0 as opposed to a lower value?

Response:

Please refer to the response to BCUC IR 1.91.1.

90.2 Given that the recent Billing Index SQI values have all been less than one, why is FBC proposing that the Threshold value be maintained at 5.0?

Response:

FBC believes the existing threshold of 5.0 remains appropriate as it is based on achieving specific performance for each of the billing sub measures.

Please refer also to the responses to BCUC IRs 1.84.5.1 and 1.91.1.

91.0 Reference: Exhibit B-1, pages C-150, C-151 and C-152 to C-153

91.1 Please explain: i) what types of calls are included in the calculation of the proposed ASA SQI (i.e., is it all calls received including those where the customer receives the information they seek from a recorded IVR message) and ii) how the value is calculated in the case of calls responded to by an IVR message versus in-person).

Response:

All calls where the customer selects to speak to the customer service representative (CSR) and are answered in the Emergency, Non-Emergency, Trouble and Non-Trouble queues[1] are included in the calculation of ASA. A call is considered to be answered only when a customer is connected with a CSR.

All calls resolved by the automated IVR system, for example a balance inquiry, prior to the customer selecting to speak to a CSR are not part of the ASA calculation.

Please also refer to the response to BCUC IR 1.88.4.

92.0 Reference: Exhibit B-1, pages C-155 to C-168

92.1 In Table C8-1, FortisBC discusses targeted incentives. Please provide the analysis or other research in support of the proposed incentive.

Response:

Appendix C4-1 of the Application explains the rationale for adopting alternative incentive frameworks that are beyond mere cost reduction and provides some examples in other jurisdictions. Further, Appendix C4-2 of the Application provides a more detailed discussion of the alternative incentive framework adopted in two U.S. jurisdictions (the Appendix particularly explains New York Public Service Commission's rationale for adopting positive only incentives).

Additional cost/benefit analysis for the proposed incentives is provided in the response to BCUC IR 1.96.7.

92.2 Who will pay the costs of each of the initiatives, will they be included in formula O&M and Capital?

Response:

Please refer to the response to BCUC 1.96.9.1.

92.3 In Table C8-2, the annual renewable gas volume target is provided for FEI.

92.3.1 Please provide the actual renewable gas volumes achieved in each of 2013-2018.

Response:

The following table shows the actual RNG volumes each year from 2013 to 2018.

RNG Volume by Year	2013	2014	2015	2016	2017	2018
Supply (TJ)	93.1	105.4	132.8	133.6	155.0	178.1

92.3.2 Please provide an indication of the plans to achieve the proposed target.

Response:

Please refer to the response to BCUC IR 1.97.3.

92.4 In Table C8-3, the annual natural gas for transportation consumption volume target is provided for FEI.

92.4.1 Please provide the actual annual natural gas for transportation consumption achieved in each of 2013-2018.

Response:

The table below provides the actual annual natural gas for transportation demand each year from 2013 to 2018.

TJ per year	2013	2014	2015	2016	2017	2018
Natural Gas for Transportation	0.37	0.77	1.02	1.16	1.52	2.04

92.4.2 Please provide an indication of the plans to achieve the proposed target.

Response:

Please refer to the responses to BCUC IRs 1.98.1 and 1.98.2.

92.5 In Table C8-5, the annual natural gas conversion target is provided for FEI.

92.5.1 Please fully explain why the target is not an extrapolation of the data in table C8-5.

Response:

FEI understands the question to be regarding an extrapolation of the data in Table C8-4 (not C8-5).

An average approach takes a data series and smooths the fluctuations in the data points to show an average. The aim is to take out the extremes of data from period to period. Whereas, extrapolation involves the use of trends established by historical data to make predictions about future values. The basic assumption of extrapolation is that the pattern from the historical data points will continue into the future unless evidence suggests otherwise. FEI believes that the historical data points are not representative to make future predictions because:

- The operating environment is becoming more challenging which limits FEI's ability to attach new customers as described in the response to BCUC IR 1.1.1, 1.1.1.2, 1.2.1, 1.2.3 and 1.13.11.1; and
- The level of activity, as measured by housing starts, has slowed and is expected to decline further as illustrated in the response to BCUC IR 1.41.3.

92.5.2 Please provide an indication of the plans to achieve the proposed target.

Response:

Please refer to the response to BCSEA IR 1.13.1.

92.6 In Table C8-7, the annual emissions intensity target is provided for FEI.

92.6.1 Please confirm that FEI has achieved reductions in the order of 643-721 in the years 2013-2017 yet only proposes reductions averaging 30 as a target. If not confirmed, please fully explain.

Response:

Not confirmed. Table C8-7 presents the Emissions Intensity (not level of emissions) for the period between 2013 through 2017. Emissions Intensity ranged from 643 to 721 tCO_2e/PJ during this period. It is incorrect to assume that "FEI achieved reductions in the order of 643-721…". Please also refer to the response to BCSEA IR 1.14.1.

92.7 In Section 8.3.5, FEI and FBC discuss Customer Engagement.

92.7.1 Please confirm that the examples used, such as the use of digital channels to avoid phone calls actually reduces the costs of FEI and FBC. If not confirmed, please fully explain.

Response:

Not confirmed. Although it is likely that a portion of calls will be reduced by the increased use of digital channels, the increased use of digital channels does not necessarily reduce costs to support customer experiences incurred by FEI and FBC. There are a few reasons for this:

- First, with enhanced access to meet the needs of customers, it is possible that the total volume of interactions overall may increase. That is, more customer may be reaching out more frequently to get information, support they require and complete transactions because it may be easier and more convenient for them. As result, an increase in digital interactions does not equate to an equal and offsetting decline in call volume.
- Second, digital and self-service channels tend to lend themselves well to less complex experiences and interactions. To the extent that a more complex need is present or develops, the support for that customer must be in place to deliver on expectations. In addition, the more complex interactions handled via the phone channel may require more time on average to resolve and respond to as compared to the average time experienced today.
- Third, to the extent that channels such as email (and potentially text message and/or chat capabilities in the future) remain personalized and require some form of human

intervention, a customer service representative or billing analyst will continue to be required to respond to these channels on a real time basis.

- Finally, costs incurred within the contact centres are reflective of the resources required to meet service level expectations, most notably the Telephone Service Factor (TSF) and FCR. Ultimately, in order to result in reduced costs, the impact of digital channels would need to shift total interactions in such a way that the Companies were able to meet customer expectations with less overall FTEs. While FortisBC does not expect lower FTEs in the MRP term at this time, any reduction in FTEs would positively impact customers by reducing costs.

The Companies are pursuing increased adoption of digital channels primarily to enhance the customer experience and increase customer engagement. While cost reductions are a consideration, and the Companies will continue to pursue programs and targeted initiatives to provide high quality service at the lowest reasonable cost, the key driver is to meet customer expectations around the availability of various channels to support their needs.

92.7.2 Please fully explain why FBC and FEI shareholders should not pay for improved customer engagement in order to enhance productivity.

Response:

Please refer to the response to BCUC IR 1.96.1.

92.8 In Section 8.3.6, FBC discusses Growth in Electric Vehicle Transportation.

92.8.1 Please fully explain when FBC expects to propose targets.

Response:

Please refer to the response to BCSEA IR 1.16.1.

92.8.2 Please fully explain why FBC shareholders should not pay for this initiative.

Response:

Please refer to the response to BCUC IR 1.96.1.

93.0 Reference: Exhibit B-1-1, Appendix C2

93.1 Please fully explain the purpose of each benchmarking report. What information and conclusions are parties to draw from each report?

Response:

The following comments have been prepared by FortisBC.

Please refer to page B-48 of the Application referencing the BCUC's direction to FEI and FBC to prepare the benchmarking studies. In the direction, the BCUC indicated:

> A benchmarking study would provide the Commission with such 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.

FortisBC understands that, consistent with the BCUC directive, the benchmarking study along with other considerations were intended to inform the BCUC's decision on the relative efficiency of FortisBC for its next MRPs.

The following portion of the response has been prepared by Concentric.

The purpose of the benchmarking reports was to examine the efficiency of the FBC and FEI in terms of their O&M expense profile, capital investment, reliability, customer service, and other factors on a stand-alone basis as well on a relative basis against their peers.

93.2 Concentric, please confirm that for transmission and distribution, the costs of a utility do not significantly vary with the volume of energy shipped through the system. If not confirmed, please fully explain.

Response:

The following response has been prepared by Concentric.

Confirmed.

93.3 Concentric, please fully explain why measures that are based on peak demand are not included in the study.

Response:

The following response has been prepared by Concentric.

As stated in the benchmarking study, the metrics were chosen in consultation between the Company and stakeholders. While metrics utilizing peak demand can be potentially useful for purposes of benchmarking a utility's performance, Concentric's view is that the set of metrics analyzed in the study provides for a reasonably comprehensive overview of FortisBC's relative performance on both a financial and non-financial basis.

93.4 Concentric, please confirm that ATCO Gas Distribution and Enbridge Gas Distribution have no transmission function. If not confirmed, please fully explain.

Response:

The following response has been prepared by Concentric.

Confirmed.

93.5 Concentric, please confirm that ATCO Electric Distribution FORTIS Alberta do not include any transmission function. If not confirmed, please fully explain.

Response:

The following response has been prepared by Concentric.

Confirmed.

93.6 Concentric, please explain which of ENMAX is included, ENMAX Corporation, ENMAX Power Corporation, or ENMAX Power Corporation Distribution.

Response:

The following response has been prepared by Concentric.

ENMAX Power Corporation.

93.7 Concentric, please explain which of EPCOR is included, EPCOR Utilities Inc., EPCOR Distribution and Transmission Inc. (EDTI), or EDTI Distribution.

Response:

The following response has been prepared by Concentric.

EPCOR Distribution and Transmission Inc.

93.8 Concentric, for each of the comparators, please provide a discussion of the geographic area the utility operates in, including climate, density, compared to FEI and FBC.

Response:

The following response has been prepared by Concentric.

For the FEI study, the Province (or State) of operation for each comparator is provided in Figure 1 on page 5 of Appendix C2-1. Similarly, for the FBC study, the Province (or State) of operation for each comparator is provided in Figure 1 on page 5 of Appendix C2-2.

Concentric did not analyze the geographic area beyond the Province (or State) of operation. Concentric also did not study climate and density of the comparators. As stated in the benchmarking study, the industry peer groups used in the studies were selected according to criteria designed to produce peer groups with operating circumstances similar to FEI and FBC. The criteria were also determined to allow for a peer group size that would provide a sufficiently broad perspective for industry comparisons. While additional criteria such as climate and density may also provide useful information from a benchmarking perspective, the further refinement of the peer groups to reflect such criteria would likely result in an overly small peer group that would produce less meaningful benchmarking results.

93.9 Concentric, please fully discuss how different utilities use of technology, and the tradeoff between capital and O&M was factored into the benchmark.

Response:

The following response has been prepared by Concentric.

Concentric did not directly consider the impact of use of technology by various utilities in the benchmarking study. The tradeoff between capital and O&M was factored into the study by analyzing both O&M and net plant figures to provide a more complete review of FBC's (and FEI's) financial position and cost structure relative to the peer group companies.

93.10 Concentric, please fully explain what data normalization between peers was done. In the response, please discuss the Concentric normalization approach and method used.

Response:

The following response has been prepared by Concentric.

As stated in the Report, since the companies in the peer groups had different mixes of function within their operation profile, Concentric focused 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.

Since publicly available data for Canadian Utilities was insufficient to complete the Study, Concentric had to develop a data survey for use in the direct request of data from Canadian utilities. The steps taken to gather and normalize the data are provided in Appendix B of each of the reports.

94.0 Reference: Exhibit B-1-1, Appendix C3

94.1 On PDF page 360 there is a Map of Canada. The map indicates that the Yukon and Northwest Territories have Electric MRPs. Please provide the utility that has an MRP and the nature of the MRP for each utility.

Response:

The above referenced map is sourced from a study prepared by PEG for Edison Electric Institute titled "Alternative Regulation for Emerging Utility Challenges: 2015 Update" and can be retrieved from the following link: http://www.puc.pa.gov/pcdocs/1418301.pdf

Table 7 in the referenced report provides the following information regarding the MRP design in Yukon and NWT.

Jurisdiction	Company	Term	Services covered	Rate Escalation Provisions	Earning sharing provisions	Case Reference
Yukon	Yukon Electrical Company	2013-2015	Bundled power service	Revenue cap stairstep	None	Order 2014-06; April 2014
NWT	Northland Utilities	2011-2013	Bundled power service	Revenue cap stairstep	None	Decision 17-2011; Nov 2011

FortisBC has not done any further review of these rate plans.

95.0 Reference: Exhibit B-1-1, Appendix C4-3

In Appendix C4-3, there is a discussion of the fundamentals of rate setting, but a discussion of the origins and issues with the process is missing.

95.1 Please fully discuss the original intent of price regulation of natural monopolies. In the response, please fully explain how the initial intent was to protect customers from the market power of natural monopolies.

Response:

FortisBC agrees that a central consideration in the economic regulation of natural monopolies is to protect the customers of the regulated entity from the abuse of monopoly power. The nature of public utilities, as well as the legal, economic and theoretical rationale for the regulation of public utilities has been explained extensively in regulatory textbooks such as "Principles of Public Utility Rates, 2nd Edition" by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen ("Bonbright"), "The Regulation of Public Utilities, 3rd Edition" by Charles F. Phillips, Jr. and others. The regulation of public utilities in British Columbia has been carried out by the BCUC under the authority given to it by the *Utilities Commission Act* with consideration as appropriate of other relevant legislation, regulations and policy. The BCUC issues orders, decisions and reports, as well as guidelines and rules of practice in keeping with its jurisdiction under the UCA. While regulatory theory from textbooks and regulatory practice in other jurisdictions are referenced frequently in the BCUC regulatory processes, the BCUC must make its determinations based on the particular legal and policy framework it is subject to in British Columbia, as well as the factual circumstances presented in a particular process.

96.0 Reference: Exhibit B-1-1, Appendix C6-1

96.1 Please provide an exhaustive list of Concentric clients.

Response:

The following response has been prepared by Concentric.

Concentric's clients include a broad range of North American utilities (gas, electric and water), electric generation companies, midstream natural gas companies, wholesale and retail energy marketing companies, large energy consumers, financial investors, law firms, industry organizations, governmental and regulatory agencies. A specific client listing is confidential.

96.2 Please identify the sponsors of the report.

Response:

The following response has been prepared by Concentric.

The report was sponsored by the Canadian Gas Association and the Canadian Electricity Association.

96.3 Please provide a detailed discussion of the successes and failures of ratepayer-funded innovation.

Response:

The following response has been prepared by Concentric.

Page 6 of the report notes, "Given the relatively new nature of utility funded innovation, it is difficult to measure success," thus, Concentric's report did not focus on program results. Some notable and more established programs are Ofgem's, which estimate benefits in the 4.5-6.5 times funding level range. There are also general benefits and drawbacks to ratepayer-funded innovation that may be noted. As discussed in the report, utility ratepayer-funded innovation may provide cleaner, less expensive energy services to customers, while also boosting economic development. Innovations may help to avoid costly infrastructure investments, or aid customers in managing their energy use and saving money on their bills. With this in mind, regulators must weigh program costs, and may find benefits difficult to quantify. Still, as cited in the report, some studies estimate the potential consumer benefits from innovation activity outweigh the costs by up to 5:1 multiples.

96.4 Please provide a detailed discussion of how the benefits of ratepayer funded innovation were apportioned between customers and shareholders. Did customers gain access to intellectual property rights for inventions that had commercial value? Were customers compensated when innovation was successful and had commercial value?

Response:

The benefits of investment in innovation are multi-faceted and dependent on the outcomes of the investment. Successful innovation leads to three broad and mutually interdependent outcomes:

i) advancement in technological development and/or application to practical use-cases;
ii) lowering costs and increased experience with new technologies and practices; and
iii) expanding market share and adoption of technologies and practices.

Along these outcomes, the benefits of innovation could be categorized in the following categories:

1. Social benefits • GHG reductions • Spillovers to other sectors • Macroeconomic	**2. System operator benefits** • Resiliency and supply security • Increased system efficiency and management • Lower costs and consumer retention and/or growth
3. Privatized benefits • Intellectual property development • Financial: market share, revenue and earnings	**4. Gas consumer benefits** • Avoided costs • Resiliency and supply security • Enhanced technologies and/or services

1. **Social benefits** are typically non-exclusionary by nature. For example, society as a whole enjoys the avoided costs that come with greater GHG reductions. Furthermore,

innovation spillovers to other sectors are difficult to predict but can lead to growth, employment, and/or lower costs to other sectors outside of the regulated utility. Should these factors be significantly large, then macroeconomic outcomes would be greater and enjoyed by a large section of society. In this sense the benefits are split more-or-less evenly across society as a whole.

2. **System operator benefits and gas customer benefits** are closely tied. For example, should innovation improve the system's resilience and supply security, the network operator would benefit from lower risks and improved system management while the consumer would benefit from otherwise lower system and network costs and lower risk of disruption. System operators also could benefit from improved and more efficient system management. Lower costs would see greater consumer retention and possibly growth on the system. The system operator would benefit from greater utilization of its infrastructure under carbon reduction goals. In addition to lower costs, innovation could bring enhanced products and services to gas consumers. As an example, innovation that would drive down the costs of gas heat pumps could offer higher-quality services for consumers with lower overall bills.

3. Finally, **privatized benefits** are borne by those who develop and successfully market the technologies that receive innovation funds. Privatized benefits are essential to ensure there are incentives for innovators to take on risk and develop products or services.

A detailed evaluation of the benefits of Low Carbon Networks Fund (LCNF) was conducted for Ofgem in the UK which estimated the scale and share of benefits of a fund designed to stimulate innovation by distribution network operators. The LCNF was a GBP $250 million fund open to six electric distribution operators to explore new technologies and develop alternative operating regimes and commercial arrangements. The LCNF's stated objects were to incentivise operators to include innovation as a part of their core businesses and to facilitate low-carbon and energy saving initiatives. The evaluation estimated that the longer-term net-benefit of the LCNF was 4.5 to 6.5 times the cost of funding the scheme and that over half of the value of benefits flowed outside of the distribution network operator. This justified the use of the LNCF as a means to incentive operators to invest in innovation even though much of the benefit does not accrue to them.[10]

Please also refer to the responses to BCUC IR 1.70.6, 1.71.4, 1.81.1 and BCOAPO 1.85.3.

[10] Poyry (2016). An Independent Evaluation of the LCNF, https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf Pages 2, 84.

96.5 Please confirm that customers have no way to opt out of these programs if they disagree with the way the money is spent. If not confirmed please fully explain.

Response:

All customers within a rate class pay under the same tariff. If the Clean Growth Innovation Fund rate rider is approved as proposed, all customers will pay the same amount toward the fund.

97.0 Reference: Exhibit B-1, pages D-35 to D-36

97.1 Please explain how the results of the Lead-Lag Study will be used during the 2020-2024 MRP period to calculated cash working capital (i.e., will the 9.5 net lead-lag days value be applied to the total forecast expenditures for each test year (2020-2024) or will the proposed lead-lag day values for each individual revenue and expense item be applied to the forecast test year values for each and a new net lead-lag value derived for each test year?

<u>Response:</u>

Consistent with current practice, the proposed lead-lag day values for each individual revenue and expense item will be applied to the forecast test year values for each, and a new net lead-lag value derived for each test year.

98.0 Reference: Exhibit B-1-1, Appendix D3-2, pages 3 and 8

98.1 With respect to Table I-1, please provide the equivalent table as used to determine the approved Lead-Lag Days for each customer class as set out on page 3.

Response:

Please see the table below summarizing the Lead-Lag Days associated with Sales Revenues based on the previously approved method. The Billing to Collection and Proportion Billed in the calculation of the previously approved method were based on high level assumptions compared to actual data used (2017 data) in the 2018 Lead-Lag Study.

	Service Period to Meter Read		Proportion Billed		Service	Meter Read to Billing	Billing to Collection		Proportion Billed		Collection	Total
Customer Class	Monthly	Bimonthly	Monthly	Bimonthly	Lag	Billing Lag	Monthly	Bimonthly	Monthly	Bimonthly	Lag	Lag Days
	a	b	c	d	e=a*c+b*d	f	g	h	i=c	j=d	k=g*i+h*j	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

98.2 Why has the Residential Lead-Lag Days increased from 50.5 to 56.0?

Response:

As discussed in the response to BCUC IR 1.134.3, the updated 2018 Lead-Lag Study used actual 2017 data, which provided 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 Residential lag has been increased by 5.5 days from 50.5 days to 56.0 days and is further explained as follows.

Collection Lag:

Residential collection lag has been increased by 5.1 days due to:

- A 5.3 days increase due to longer collection lags in the 2018 Lead-Lag Study than the previously approved method (22.2 and 27.3 versus 17.0 and 22.0 for monthly and bi-monthly billings, respectively), the latter which assumed that payments were received on the due date;

partially offset by

- A (0.2) days decrease due to a higher proportion of monthly billings compared to bimonthly billings in the 2018 Lead-Lag Study, as monthly billings have a lower collection lag than bimonthly billings.

Billing Lag:

Residential billing lag has been increased by 1 day, from 1 day in the previously approved method, to 2 days in the 2018 Lead-Lag Study. Please refer to the response to BCUC IR 1.134.3 for details on this change in billing lag.

Service Lag:

Residential service lags were assumed to be 15.2 and 30.4 for monthly and bimonthly billings, respectively, which resulted in no change from the 2018 Lead-Lag Study compared to the previously approved method. However, Residential service lag has been decreased by (0.6) days due to a higher proportion of monthly billings compared to bimonthly billings in the 2018 Study (monthly billings have a lower service lag than bimonthly billings).

98.3 In Table I-1, does the "Proportion Billed" refer to the proportion of customers or the proportion of revenue in each class?

<u>Response:</u>

The "Proportion Billed" refers to the proportion of the revenue in each class.

98.3.1 If based on proportion of customers please recalculate Table I-1 using the proportion of revenue received from monthly vs. bi-monthly billing.

<u>Response:</u>

Please refer to the response to BCOAPO IR 1.98.3.

98.4 What initiatives, if any, does FBC have to in place to encourage customers to adopt monthly billing?

Response:

Monthly billing is offered to customers when the opportunity arises. Examples include when a customer calls to set up an account and when a customer contacts FBC about bill payment challenges they may be facing.

99.0 Reference: Exhibit B-1-1, Appendix D3-2, pages 4 and 8

99.1 Please confirm that Late Payment charges are effectively interest charges on overdue accounts.

Response:

While the determination of Late Payment charges involves an interest rate, Late Payment Charges are more appropriately considered a revenue stream pursuant to the applicable rate schedule under the current FBC Tariff, as well as under US GAAP. As a result of implementing Accounting Standards Codification 606 revenues with customers, effective January 1, 2018, Late Payment charges are considered other revenue and are recorded as income within trade receivables for external financial reporting purposes.

With respect to the payment of interest on debt, it is not a function of a utility's operations like the other operating expenditures included in FBC's lead-lag study. Rather, interest forms a component of the rate of return and, therefore, is appropriately excluded from the calculation of the cash working capital allowance.

99.2 Please explain why Late Payment charges (interest revenue) are included in the Lead-Lag Study when interest expense is not (per page 4).

Response:

Please refer to the response to BCOAPO IR 1.99.1.

100.0 Reference: Exhibit B-1-1, Appendix D3-2, page 11

100.1 With respect to Table III-1, please explain what "Power Purchase-Return on Capital" represents and how the Service Lead and Payment Lead values were determined.

Response:

Power Purchase-Return on Capital represents the purchase for energy provided by the Brilliant plant. These Return on Capital purchases are pursuant to a 60-year agreement beginning April 1996 (Brilliant Power Purchase Agreement) which allows FBC to take all the entitlement from the Brilliant plant, in exchange for Return on Capital payments made every May and November. The Service Lead of 182.5 days is calculated as the mid-point of a year (365/2), assuming equal daily service throughout the year. The Payment Lead of (129.2) days is the dollar weighted number of days between the deemed receipt of service and the payment dates. Please see the table below for the calculation of the Payment Lead.

	Amount ($000s)	Dollar Weighting	Deemed Receipt of Service	Payment Date	Payment Lead	Weighted Lead Days
	(a)	(b)	(c)	(d)	(e)=(d)-(c)	(f)=(b) x (e)
Power Purchase - Return on Capital 1	15,929	50.5%	31-Dec-17	22-Nov-17	(39.0)	(19.7)
Power Purchase - Return on Capital 2	15,644	49.5%	31-Dec-17	24-May-17	(221.0)	(109.5)
Total	**31,573**	**100.0%**				**(129.2)**

101.0 Reference: Exhibit B-1, page D-38

Preamble: At page D-38 the Application states: "Compared to the existing Timesheet Approach, the Cost Driver Approach is more efficient to administer while providing an allocation methodology that reasonably represents the sharing of resources. A Cost Driver Approach would require minimal timesheets / journal entries to be processed, and the cost drivers would require only annual updating with a broader review of the shared services model on a longer-term basis".

101.1 Which approach is more accurate in terms of identifying the actual cost of service shared between FEI and FBC? If the Cost Driver Approach is considered more accurate please explain why.

Response:

As indicated by results in the study based on 2018 actuals, the Cost Driver approach generates similar results as the Timesheet approach, suggesting both are "accurate".

FortisBC is recommending the adoption of the Cost Driver approach as it is simpler to understand, easier to administer and more efficient and more stable over time, while providing an allocation methodology that reasonably represents the sharing of services.

101.2 What are the estimated efficiency gains for each of FEI and FBC as a result of adopting the Cost Driver Approach (e.g., $ savings in staff time)?

Response:

FortisBC expects some labour related efficiencies from the implementation of a Cost Driver approach due to less administrative time required for preparing and processing timesheets and journal entries. At a high level, FortisBC estimates the savings to be approximately 0.25 to 0.50 FTE annually spread across various departments. FortisBC notes no FTE reductions are anticipated and instead the additional labour resources available will be redirected to support other activities, consistent with the Companies' focus of "doing more with what we have".

102.0 Reference: Exhibit B-1, page D-39 (Table D4-2)

Exhibit B-1-1, Appendix D4, pages 4 and 9

Preamble: Appendix D4, page 4, Footnote 4 states: "Given their specific nature, costs related to resources provided in support of Capital Projects and Other activities (Deferral – Demand Side Management) will continue to be allocated using the existing timesheet cross charge methodology. Additionally, only labour costs for the Shared Services is subject to the Cost Driver approach as non-labour expenses (i.e., travel expenses) may be charged directly to each company instead".

102.1 Do the costs set out in Table D4-2 include: i) the costs related to resources provided in support of Capital Projects and Other activities or ii) non-labour expenses as referenced in Footnote 4?

Response:

The costs set out in Table D4-2 are for FEI and FBC shared O&M labour costs and do not include costs related to labour provided in support of capital projects and other activities and also do not include non-labour expenses.

102.1.1 If yes, do the allocations shown in Table D4-2 reflect the fact that the allocation methodology for these costs has not changed?

Response:

Please refer to the response to BCOAPO IR 1.102.1.

102.1.2 IF yes, please provide a revised version of Table D4-3 that separates out those costs that will continue to be allocated using the existing timesheet cross charge methodology from those to which the new methodology will be applied.

Response:

Please refer to the response to BCOAPO IR 1.102.1.

102.1.3 If no, please reconcile this response with the fact that the total shared costs set out for FEI and FBC in Table D4-2 match the total of all shared costs for each utility as set out in Appendix D4, Table A:D4-2.

Response:

FortisBC clarifies that Table A:D4-2 in Appendix D4 shows the shared 2018 O&M labour costs for FEI and FBC as indicated in the columns Shared, FEI (25,392) and FBC (7,459) and does not include other costs such as non-labour expenses which may be directly charged to each company instead. Provided in the table also is the total 2018 O&M costs not subject to sharing between FEI and FBC.

Similarly, the same shared 2018 O&M labour costs are shown Table D4-2 as indicated in the columns, 2018 Identified Shared Costs, Gas (25,392) and Electric (7,459).

For clarity, FortisBC notes that the proposed Shared Services approach applies only to O&M related shared labour services between FEI and FBC.

103.0 Reference: Exhibit B-1, page D-39 (Table D4-2)

103.1 Please explain why for Regulatory and Operations the split of Shared Costs between FEI and FBC is different under the current vs. proposed approach when the proposed approach also used time estimates – similar to the current approach.

Response:

Table D4-2 on page D-39 of the Application is not comparing the difference between the current Timesheet Approach (i.e. cross charge) to the proposed Cost Driver Approach. Instead, it is summarizing the identified shared costs of $32.851 million and showing the calculation of the allocations in the proposed Cost Driver Approach. For example, the changes in the Regulatory and Operations functions as reflected in the columns titled "Difference – Gas and Electric" on Table D4-2, are showing how shared costs are allocated using the proposed Cost Driver approach. The result is a net allocation of costs from FBC to FEI of $1.045 million.

A comparison of the current Timesheet Approach and the Cost Driver Approach is provided in Table A:D4-4 in Appendix D-4 of the Application. In the table, FortisBC notes there is no change in the Operations function allocation between the current Timesheet Approach and the proposed Cost Driver Approach, as shown in the columns titled "Difference, Overall Impact – Gas and Electric". The Regulatory function sees a minor change of $83 thousand due to the Cost Driver Approach using a time estimate allocation basis of 80 percent Gas and 20 percent Electric. Under the current Timesheet Approach, the time estimate allocation basis is 76 percent Gas and 24 percent Electric. When FortisBC undertook its review of the allocation basis for the Regulatory function, it was concluded that an 80/20 split was a more accurate representation of the level of shared services on an ongoing basis. This is now included as part of the proposed Cost Driver Approach.

As shown in Table A:D4-4, the overall net difference between the Cost Driver Approach as described above (net allocation from FBC to FEI of $1.0.45 million) and the current Timesheet Approach (net allocation from FBC to FEI $1.382 million) is a $0.338 million reduction in the allocation from FBC to FEI.

104.0 Reference: Exhibit B-1, pages C-44, C-110 and D-41

104.1 Please confirm that, apart from the initial adjustment to the 2019 O&M (per page C-44) the Corporate and Shared Services Studies have no impact on the forecast O&M that will be used for rate setting for FEI and FBC over the 2020-2024 period. If not confirmed, please explain why not.

Response:

Confirmed. The forecast 2019 Base O&M, which includes the forecasted effect of implementing the new Corporate Services and Shared Services Studies, will be utilized to set index-based O&M, and revenue requirements for 2020 through 2024.

104.2 Please confirm that the Corporate and Share Services Studies will have an impact on the actual O&M costs for FEI and FBC over the 2020-2024 period and therefore impact the Earnings Sharing Mechanism calculations. If not confirmed, please explain why.

Response:

The forecast 2019 Base O&M, which includes the forecasted effect of implementing the new Corporate Services and Shared Services Studies, will be utilized to set index-based O&M and revenue requirements for 2020 through 2024. Therefore, should there be any variances between the actual charges and the amounts embedded in the index-based O&M (whether related to Corporate and Shared Services Studies or otherwise), such variances will be subject to the earnings sharing mechanism.

105.0 Reference: Exhibit B-1, page D-44 to D-45

105.1 Are FEI's and FBC's regulated capital structures and regulated return on equity based on FEI's/FBC's or FI's risk profile?

<u>Response:</u>

The widely accepted Stand-Alone Principle provides that the utility must be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. As such, FEI's and FBC's regulated capital structure and authorized return on equity are set based on FEI's and FBC's standalone risk profile and not that of Fortis Inc.

105.2 Is FI able to obtain equity at a lower cost than FBC or FEI would incur if they operated separately? If yes, how do FEI's and FBC's customers benefit from this ability?

<u>Response:</u>

Accessing equity indirectly through FI is more cost effective for FBC and FEI customers than accessing equity independently. In order for FEI and FBC to directly access equity markets efficiently, they would need to be listed on the Toronto (TSE) and/or New York (NYSE) stock exchanges, which would require significant regulatory and reporting requirements with associated costs. FI is registered and listed on the NYSE and the TSE with a market cap of approximately CAD$21.9 billion with daily trading volume of approximately 400,000 shares. It is more cost-effective for FBC, FEI and FI's other utility subsidiaries to utilize this broad centralized platform while sharing the costs related to maintaining the capital market and investor relations functions at FI.

106.0 Reference: Exhibit B-1, page D-45

106.1 Please provide specific examples of how/where over the past three years each of FEI and FBC have benefitted from the strategic oversight and sharing of best practices across the group of FI companies.

Response:

In addition to accessing the capital markets to enable equity financing for the regulated entities, including FEI and FBC, FI provides strategic oversight and sharing of best practices as described in MRP Sections D5.3.2.2 *Benefits of Strategic Oversight and Sharing of Best Practices from FI* and D5.3.2.3 *Benefits from FI Administered Company-wide Group Insurance Program*. Examples of benefits received through FI and the FI group of companies over the last three years include the following:

- Determining sustainability reporting requirements beginning in 2017, which was the culmination of a joint effort across the FI group of companies and FI. Although sustainability activities have previously been incorporated in FortisBC's business, working within a broader group helped to define FortisBC's four sustainability pillars: Customers, Partners & Communities, Environment and Employees.
- Collaboration between FortisBC and FI on developing a Fortis-wide Cybersecurity Risk Management Program and Framework in 2018 for implementation at the subsidiaries beginning in 2019.
- The FI group of companies' procurement departments have leveraged the economies of scale to enter into competitive purchasing agreements for transformers, wires, poles and other materials. In 2017, a new agreement to procure transformers was entered into and the pricing was based on the bargaining power of the entire FI group of companies, which was enabled through FI's best practices and collaboration of the operating subsidiaries.
- Sharing of best practices and experiences amongst the FI group of companies for financial reporting, internal audit, information systems, customer service, legal, tax and operations & engineering.
- Sharing of expertise and interpretation amongst the FI group of companies around the implementation of new accounting standards, for example the new revenue standard, Accounting Standards Codification (ASC) 606 effective 2018, and the new lease standard, Leases ASC 842 effective 2019.

107.0 Reference: Exhibit B-1, pages D-43 and D-46

Exhibit B-1-1, Appendix D5, pages 13-14

107.1 Please provide schedules that set out the derivation of the 21.9% Asset Allocation factor and the 19.9% Controllable Cost Allocation factor for FortisBC Subsidiaries.

<u>Response:</u>

Please refer to the response in BCUC IR 1.141.2.

108.0 Reference: Exhibit B-1, page D-47

Exhibit B-1-1, Appendix D5, pages 15 and 16

108.1 Please provide a schedule that sets out: i) FI's total 2018 costs based on the categories used in Table 5.5 (Appendix D5); ii) the portion of each that is excluded from recovery and iii) the portion allocated to FortisBC Subsidiaries.

Response:

FI's total 2018 costs based on the categories used in Table 5.5 of Appendix D5 can be back-calculated based on using the 21.4 percent allocation to the FortisBC Subsidiaries as shown in the table below. The FI costs are net of the specified exclusions, since FI did not recover all its costs from its subsidiaries. As discussed in Section 5.3 on pages 12 and 13 of Appendix D5, there are various specified exclusions that are not passed on from FI to their regulated utilities in the form of a management fee.

2018 FortisBC Subsidiaries and FI Costs Eligible for Allocation

FI Recoverable Cost Categories	FortisBC Subsidiaries Portion of FI Costs 2018 ($) Forecast
Salaries (Excl EVPs, Western & Eastern Utility Ops) Operations)	$3,993,593
Directors' fees and costs	726,480
Trustees and DRIP administration	128,109
Consulting	485,009
Legal	703,729
Audit	291,306
Listing and filing	312,094
Annual meeting and report	206,915
Other fees	91,373
Insurance	223,172
Office related	666,432
Investor Relations	151,225
Communications	61,262
Miscellaneous	10,689
Travel	291,452
Telephone	39,668
Recoverable Amount	$8,382,508
2018 FI Costs Eligible for Allocation to Subsidiaries	$39,170,598
FortisBC Subsidiaries Proportion	21.40%

108.2 Please clarify whether the costs used in Tables 5.5 and 5.6 are forecast (as per the title) or actual 2018 costs.

Response:

FortisBC confirms that the costs used in Tables 5.5 and 5.6 are forecast.

108.2.1 If forecast costs were used, please re-do both tables using actual 2018 costs.

Response:

Please refer to the response in BCUC IR 1.142.1.

108.3 Are 100% of FI's Board of Directors costs included for recovery and subject to the 21.4% allocation factor?

Response:

As discussed in Section 5.3 on page 12 of Appendix D5, with the exception of meals and entertainment, all other costs of FI's Board of Directors are included in FI corporate services allocated to FI subsidiaries.

FI's Board of Director costs are allocated to both FI's regulated and non-regulated operations through the asset and controllable operating cost allocation methodology. The rationale for allocating these Board of Directors costs to the subsidiaries rests not only on the governance and oversight of the operating subsidiaries, but also on securities requirements. Having a competent and independent Board of Directors is a compliance requirement pursuant to the Ontario Securities Commission and the U.S. Securities and Exchange Commission and is therefore necessary to enable FI to participate in the public capital markets in support of FI's regulated subsidiaries maintaining their approved regulated capital structures.

108.3.1 If yes, please explain why since the Board of Directors is also responsible for oversight of the excluded shareholder related activities.

Response:

Please refer to the response to BCOAPO IR 1.108.3.

109.0 Reference: Exhibit B-1, pages D-48 to D-49

109.1 What is the difference between the Risk Management and Insurance services provided by FHI and those provided by FI (per page D-45)?

Response:

The nature of the FI and FHI insurance and risk management corporate services are different from one another and consistent with previously approved corporate service studies.

Section 5.3.2.3, Benefits from FI Administered Company-Wide Group Insurance Program, in Section D5 of the Application describes the corporate services provided by FI's risk and management and insurance services department:

> the FI corporate services include FI's cost to manage and administer the insurance program. The FI risk management department is responsible for group property and casualty insurance policies renewal processes, determining and developing risk transfer strategies, determining policy limits and optimal retention levels, handling and administration of FI group first party property damage claims and third party claims and overseeing risk and loss control inspections including the management of recommendations and subsequent response.

Section 5.5, Description of FHI Corporate Services, in Section D5 of the Application describes the corporate services provided by FHI's risk management and insurance services department:

> for managing the insurance program on a day-to-day basis. The insurance and risk management department is responsible for the renewal of all third party insurance and the cost of the premiums paid for those policies.

The FHI insurance and risk management department handles day-to-day insurance inquiries from various departments at the FortisBC subsidiary level, including contract review, project insurance, Certificates of Insurance requests and claims management.

109.2 Do FEI and FBC have their own internal audit functions?

Response:

FEI does not have its own internal audit function. Instead, FHI provides internal audit services to FEI. FBC does have its own internal audit function, which also receives internal audit services from FHI that are directly charged to FBC under the current allocation methodology. Currently, both FHI and FBC internal audit functions are managed as one group.

Under the proposed allocation methodology, the FBC internal audit function will be pooled in FHI with the FHI internal audit function. This pooled FHI internal audit function will then be allocated to FEI, FBC and ACGS based on the Massachusetts Formula effective 2020.

109.2.1 If yes, how do the services provided by these functions differ from those provided by FHI's internal audit function?

Response:

Please refer to the response to BCOAPO IR 1.109.2.

109.3 Are 100% of FHI's Board of Directors costs included for recovery from FEI, FBC and ACGS?

Response:

The Board of Directors costs that are pooled in FHI are included for recovery from FEI, FBC and ACGS.

The excluded activities are discussed in Appendix D5 in Section 6.4 FHI Specified Exclusions on pages 20-21. The Board of Directors costs included in Table 6.4 – FHI 2018 Allocation Eligible Corporate Costs are related solely to the FortisBC Subsidiaries and do not reflect governance costs for FHI operations. Therefore, there are no excluded activities to remove from the FHI Board of Directors costs in Table 6.4 in Appendix D5.

The recovery of the FI Board of Directors costs, included in Table D5-2: Projected 2018 FI Eligible Corporate Service Costs Allocated to FortisBC Subsidiaries, is described in the response to BCOAPO IR 1.108.3.

109.3.1 If yes, please explain why since the Board of Directors is also responsible for oversight of the excluded activities set out in Appendix D5 at pages 20-21.

Response:

Please refer to the response to BCOAPO IR 1.109.3.

110.0 Reference: Exhibit B-1, page D-50 (Table D5-3)

Exhibit B-1-1, Appendix D4, page 24 (Table 6.6)

Exhibit B-1, pages C-19 and C-44

110.1 The amounts set out in Table D5-3 as recoverable from FEI and FBC differ from those set out in Table 6.6. Please reconcile.

Response:

Please refer to the response in BCUC IR 1.145.2.

110.2 Is either Table D5-3 or Table 6.6 based on actual 2018 FI and FHI costs?

Response:

Both tables are based on the forecast 2018 FI and FHI costs. Please refer to the response in BCUC IR 1.145.2.

110.2.1 If not, please provide a schedule that sets out the allocation of actual 2018 FI and FHI costs to FBC and FEI based on the proposed methodology

Response:

Please refer to the response to BCUC IR 1.145.1.

110.2.2 Please provide a schedule the sets out the allocation of actual 2018 FI and FHI costs to FBC and FEI based on the currently approved methodology.

Response:

Please refer to the responses to BCUC IR 1.139.1 for FBC and BCUC IR 1.139.3 for FEI.

110.3 Please provide derivation of the adjustments for the change in Corporate Services allocation methodology used for FEI {($0.117) M per Table C2-1} and FBC {$0.367 M per Table C2-14)}.

Response:

The change in Corporate Services allocation methodology of ($117) thousand for FEI per Table C2-1 and $367 thousand for FBC per Table C2-14 is based on the 2020 variances determined in Table D5-4 on Page D-51 of the Application, discounted back to the 2018 value.

As discussed in the responses to BCUC IRs 1.24.1 for FEI and 1.34.1 for FBC, there will be an Errata filed in the near future for Table C2-1 and Table C2-14 to take into account the forecasted effect of the study in 2019 Base O&M for the term of the MRPs. However, as currently filed, below is a reconciliation of Table D5-4 showing the variances based on a forecast of 2020 management fees, discounted back to arrive at a 2018 Base O&M Adjustment. This reconciliation uses the 2019 Inflator per Table C2-1 for FEI and Table C2-14 for FBC in the Application, as well as an estimated 2020 Inflator of 2.0 percent for both Companies.

1 **Reconciliation of Corporate Services Allocation Adjustments in Base O&M**

Projected FI and FHI Corporate Services Allocated to regulated utilities	FEI	FBC
	($000s)	
2019 FHI Management Fee	12,030	
2019 FHI services direct charged to FBC		1,197
2019 FI services direct charged to FBC		1,544
Total 2019 Corporate services charged	**12,030**	**2,741**
2020 FHI Management Fee [1]	11,908	3,439
less: FBC costs now included in FHI corporate services [2]		(315)
Total 2020 Corporate services charged	**11,908**	**3,124**
Variance ($)	(122)	383
2020 Inflator	1.02000	1.02000
2019 Inflator	1.02198	1.02382
2018 O&M Base Adjustment	(117)	367

2

3

111.0 Reference: Exhibit B-1, pages D-53 to D-60

In Section 6, FortisBC discusses its Capitalized Overhead Policy

111.1 Please confirm that the formula O&M and Capital are after the allocation of capitalized overhead. If not confirmed, please fully explain.

Response:

The formula O&M is before capitalized overhead. Net O&M, as included in the annual calculation of the revenue requirement, will be after the allocation of capitalized overhead. Please see the equation below for clarity (as explained in Section 4.4 of the Application):

Net O&M for revenue requirement = index-based O&M + flowthrough items not included in the index-based O&M – capitalized overhead

Formula Capital under the proposed MRP only applies to FEI Growth capital. Capitalized overhead is added to the capital expenditures (growth, sustainment, and other, as explained in Section 3.3 and 3.4 of the Application) to be included in rate base additions.

DEPRECIATION STUDY

112.0 Reference: Exhibit B-1, Pages D-18 to D22

Based on a reading of Sections 2.2.4.2 to 2.2.4.4 – Average life Group versus Equal Life Group, it appears there is a "report" that was prepared by FEI, FBC and/or Concentric to examine the ALG versus ELG procedure for depreciation. The information provided in the above sections appears to be a summary of the report.

On page D-16, FEI stated it analyzed two options for converting to ELG and estimated the costs and feasibility of each option. On pages D-16 and D17, FEI discusses the first option. On page D-18, FEI states that in the case of Manitoba Hydro in its 2014/15 and 2015/16 General Rate Application where the ELG procedure was proposed and that: "…expert testimony was provided supporting the two different approaches to implementing ELG. [Footnote omitted] As a result of the proceeding, Manitoba Hydro was denied its request to implement ELG for rate setting."

In estimating the impact of converting to ELG shown in Table D2-6 on page D-21, FEI provides a comparison of the ALG and ELG procedure depreciation expense.

In Section 2.2.4.4, Table D2-7, FEI includes a list of utilities using either the ALG versus the ELG procedure with a remaining life basis.

112.1 Please provide a copy of the report done by FEI, FBC and/or Concentric that appears to have been used to prepare FEI's response to a direction from the BCHPA to examine the ALG versus ELG procedure. If unable to provide, please fully explain why not.

Response:

The IR refers to a direction from the BCHPA. The direction to examine the ALG versus ELG procedure was from the BCUC.

Provided below are the Life and Net Salvage tables that were developed by Concentric based on the ELG procedure and used in FEI's response to the direction from the BCUC to examine the ALG versus ELG procedure.

FortisBC Energy Inc.

SCHEDULE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
INTANGIBLE PLANT									
401.01	Franchises and Consents	40-SQ		297,252	212,425	84,827	3,208	1.08	19.90
402.01	Computer Software Application - 8 Years	8-SQ		114,130,181	65,227,079	48,903,102	6,112,888	12.50 *	3.44
402.02	Computer Software Application - 5 Years	5-SQ		20,602,390	8,282,646	12,319,744	2,463,949	20.00 *	3.05
402.03	Intangible Plant	40-SQ		1,906,591	1,073,775	832,816	20,820	2.50 *	20.99
402.11	Plant Acquisitions and Adjustments	40-SQ		62,457	62,457	-	-	-	32.00
TOTAL INTANGIBLE PLANT				**136,998,871**	**74,858,382**	**62,140,489**	**8,600,865**	**6.28**	
MANUFACTURING PLANT									
432.00	Structures	40-SQ		992,394	309,160	683,234	17,081	2.50 *	26.09
433.00	Equipment	20-SQ		516,348	236,230	280,118	14,006	5.00 *	11.68
434.00	Holders	40-SQ		2,954,888	584,808	2,370,080	59,252	2.50 *	32.39
436.00	Compressor Equipment	25-SQ		366,583	126,866	239,717	9,589	4.00 *	17.52
437.00	Measuring and Regulating Equipment	20-SQ		1,230,878	992,664	238,214	11,911	5.00 *	12.17
TOTAL MANUFACTURING PLANT				**6,061,090**	**2,249,728**	**3,811,362**	**111,838**	**1.85**	
LNG PLANT									
442.00	Structures	25-L2		5,209,412	3,670,131	1,539,281	143,750	2.76	9.90
442.01	Structures - Mt. Hayes	25-L2		19,038,721	4,618,064	14,420,657	945,820	4.97	15.24
443.00	Equipment	40-S4		16,713,755	12,310,410	4,403,345	218,844	1.31	16.58
443.05	Equipment - Mt. Hayes	60-R5		60,659,737	6,597,849	54,061,888	1,023,158	1.69	52.84
448.10	Piping	40-R3		12,433,032	1,887,707	10,545,325	350,420	2.82	30.08
448.20	Pre-Treatment	25-R3		29,241,933	7,555,227	21,686,706	1,284,252	4.39	16.88
448.30	Liquefaction Equipment	40-R3		28,883,117	4,718,462	24,164,655	811,286	2.81	29.78
448.40	Send Out Equipment	40-R2		23,555,076	3,782,268	19,772,808	721,533	3.06	27.40
448.50	Substation and Electrical	40-R2		21,790,943	3,553,200	18,237,743	665,698	3.05	27.40
448.60	Control Room	15-R3		6,354,097	2,613,477	3,740,620	438,730	6.90	8.50
449.00	Other Equipment	27-R3		25,739,908	16,141,911	9,597,997	821,714	3.19	10.58
449.01	Other Equipment - Mt. Hayes	33-R3		5,600,437	323,087	5,277,350	199,427	3.56	26.46
TOTAL LNG PLANT				**255,220,170**	**67,771,795**	**187,448,375**	**7,624,632**	**2.99**	

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
TRANSMISSION PLANT									
462.00	Compressor Structures	30-S4		31,562,024	16,731,361	14,830,663	1,124,775	3.56	13.31
463.00	Measuring and Regulating Structures	38-S2		15,076,202	7,107,561	7,968,640	375,615	2.49	20.30
464.00	Other Structures	30-R4		6,768,180	2,896,457	3,871,723	266,099	3.93	14.81
465.00	Transmission Pipeline	65-R4		1,371,509,954	395,481,214	976,028,740	21,630,941	1.58	44.75
465.11	Intermediate Pipe - Whistler	65-R3		42,295,869	5,134,387	37,161,481	746,738	1.77	49.76
465.30	Mains - Mt. Hayes	65-SQ		6,307,725	693,485	5,614,240	86,373	1.54 *	59.01
466.00	Compressor Equipment	37-R4		190,510,140	88,143,732	102,366,407	4,997,331	2.62	19.98
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5		5,340,973	1,313,881	4,027,093	166,734	3.12	24.15
467.10	Measuring and Regulating Equipment	37-R1.5		62,016,326	25,117,840	36,898,487	1,748,480	2.82	20.35
467.20	Telemetry Equipment	10-L1.5		17,220,938	8,190,973	9,029,965	2,041,794	11.86	4.29
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5		313,344	96,667	216,677	9,170	2.93	23.63
468.00	Communications Equipment	19-R3		3,765,245	4,779,395	- 1,014,151	-	-	5.00
TOTAL TRANSMISSION PLANT				**1,752,686,918**	**555,686,953**	**1,196,999,965**	**33,194,050**	**1.89**	
DISTRIBUTION PLANT									
472.00	Structures	38-R1.5		25,234,840	9,193,108	16,041,731	716,874	2.84	21.85
473.00	Services	47-R2		1,160,659,173	291,133,465	869,525,709	31,455,304	2.71	27.58
474.00A	Meter and Regulator Installations - Station Equipme	20-S0		24,885,593	17,678,848	7,206,745	1,023,956	4.11	6.63
474.00B	Meter and Regulator Installations - Meters	23-SQ		163,501,746	64,818,008	98,683,738	13,298,935	8.13	10.79
474.00	Meter/Regulator Installations	20-S0/23-SQ		188,387,340	82,496,856	105,890,484	14,322,891	7.60	**
474.02	New Meter Installations	22-SQ		132,111,279	16,651,984	115,459,295	5,248,150	4.55 *	19.46
475.00	Systems - Mains	65-R2.5		1,427,597,191	476,829,560	950,767,631	23,093,164	1.62	40.53
476.00	NGV Fuel Equipment	7-L0		613,588	2,149,456	- 1,535,868	-	-	3.22
477.10	Measuring and Regulating	33-R2		143,051,691	51,810,876	91,240,815	4,596,732	3.21	18.92
477.20	Telemetry	20-R3		14,930,538	6,075,041	8,855,497	633,811	4.25	11.65
478.10	Meters	18-R4		256,174,679	133,905,431	122,269,248	16,177,116	6.31	7.64
478.20	Instruments	35-R5		13,401,830	6,024,709	7,377,121	406,804	3.04	18.37
TOTAL DISTRIBUTION PLANT				**3,362,162,148**	**1,076,270,486**	**2,285,891,662**	**96,650,846**	**2.87**	
BIO GAS									
472.20	Structures and Improvements	36-R1.5		654,898	71,844	583,053	24,939	3.81	23.38
474.10	Meters/Regulator Installations	19-S0		226,054	28,936	197,117	17,352	7.68	11.35
475.10	Mains - Municipal Land	65-R2.5		1,655,815	68,413	1,587,402	32,277	1.95	49.18
477.40	Measuring and Regulating	30-R2		2,565,623	289,121	2,276,502	109,609	4.27	20.76
478.30	Meters	18-R2.5		35,277	8,734	26,543	2,092	5.93	12.54
418.10	Purification Overhauls	20-SQ		20,423	3,735	16,688	834	5.00 *	17.00
418.20	Purification Upgrader	20-SQ		9,794,870	1,381,044	8,413,827	420,691	5.00 *	17.36
TOTAL BIO GAS				**14,952,959**	**1,851,827**	**13,101,132**	**607,795**	**4.06**	

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Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
NG FOR TRANSPORTATION									
476.10	CNG Disp Equipment	20-SQ		12,897,495	1,832,791	11,064,704	553,235	5.00 *	17.44
476.20	LNG Disp Equipment	20-SQ		11,683,174	1,660,759	10,022,415	501,121	5.00 *	17.45
476.30	CNG Foundation	20-SQ		2,365,123	280,719	2,084,404	104,220	5.00 *	17.75
476.40	LNG Foundation	20-SQ		1,311,362	230,901	1,080,461	54,023	5.00 *	16.86
476.50	LNG Pumps	10-SQ		1,494,110	319,159	1,174,951	117,495	10.00 *	7.92
476.60	CNG Dehydrator	20-SQ		20,423	76,697	- 56,274	(2,814)	5.00 *	17.00
TOTAL NG FOR TRANSPORTATION				**29,771,686**	**4,401,026**	**25,370,660**	**1,327,281**	**4.46**	
GENERAL PLANT									
482.10	Stuctures (Frame)	25-R1.5		23,263,706	9,238,192	14,025,514	997,054	4.29	13.33
482.20	Structures (Masonry)	60-R2		114,701,266	27,102,987	87,598,278	2,216,595	1.93	39.31
483.10	Computer Hardware	4-SQ		36,928,213	16,894,852	20,033,360	5,008,340	25.00 *	1.78
483.20	Computer Software (12.5%)	8-SQ		7,197,065	3,274,486	3,922,579	490,322	12.50 *	4.57
483.25	RNG Computer Software (20%)	5-SQ		138,461	27,692	110,769	22,154	20.00 *	4.00
483.30	Office Equipment	15-SQ		3,377,105	1,713,206	1,663,899	110,927	6.67 *	6.88
483.40	Furniture	20-SQ		17,805,850	9,276,667	8,529,183	426,459	5.00 *	9.57
484.00	Vehicles	7-L1		20,521,572	7,712,662	12,808,910	3,226,410	15.72	3.72
485.10	Heavy Work Equipment	13-L0.5		905,623	485,649	419,974	66,348	7.33	6.04
485.20	Heavy Mobile Equipment	9-L1.5		5,384,508	2,856,060	2,528,449	457,804	8.50	4.72
486.00	Small Tools/Equipment	20-SQ		47,038,954	21,117,862	25,921,092	1,296,055	5.00 *	11.23
487.20	NGV Cyinders	15-SQ		12,336	8,375	3,961	264	6.67 *	4.25
488.10	Telephone Equipment	15-SQ		3,384,005	2,395,825	988,180	65,879	6.67 *	3.91
488.20	Radio Equipment	15-SQ		12,968,973	3,194,066	9,774,907	651,660	6.67 *	11.51
TOTAL GENERAL PLANT				**293,627,637**	**105,298,580**	**188,329,057**	**15,036,271**	**5.12**	
TOTAL DEPRECIABLE PLANT				**5,851,481,480**	**1,888,388,776**	**3,963,092,703**	**163,153,577**	**2.79**	

FortisBC Energy Inc.

SCHEDULE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017

DEPRECIATION RELATED TO RECOVERY OF COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LNG PLANT									
442.00	Structures	25-L2	-10	5,209,412	107,124	413,817	43,100	0.83	3.59
442.01	Structures - Mt. Hayes	25-L2	-10	19,038,721	77,894	1,825,978	120,240	0.63	5.60
443.00	Equipment	40-S4	-20	16,713,755	404,216	2,938,535	201,890	1.21	2.52
443.05	Equipment - Mt. Hayes	60-R5	-20	60,659,737	210,393	11,921,554	225,643	0.37	2.06
448.10	Piping	40-R3	-10	12,433,032	31,019	1,212,285	40,341	0.32	3.14
448.20	Pre-Treatment	25-R3	-10	29,241,933	132,082	2,792,111	165,461	0.57	4.96
448.30	Liquefaction Equipment	40-R3	-20	28,883,117	155,053	5,621,570	188,750	0.65	3.46
448.40	Send Out Equipment	40-R2	-10	23,555,076	61,993	2,293,515	83,696	0.36	3.42
448.50	Substation and Electrical	40-R2	-20	21,790,943	116,877	4,241,311	154,815	0.71	3.77
449.00	Other Equipment	27-R3	-10	25,739,908	609,578	1,964,413	232,356	0.90	4.10
449.01	Other Equipment - Mt. Hayes	33-R3	-10	5,600,437	17,818	542,226	20,494	0.37	3.93
TOTAL LNG PLANT				**248,866,073**	**1,924,047**	**35,767,315**	**1,476,786**	**0.59**	
TRANSMISSION PLANT									
462.00	Compressor Structures	30-S4	-3	31,562,024	460,094	486,767	38,604	0.12	3.69
463.00	Measuring and Regulating Structures	38-S2	-15	15,076,202	220,661	2,040,769	108,626	0.72	3.21
464.00	Other Structures	30-R4	-5	6,768,180	44,193	294,216	21,537	0.32	4.25
465.00	Transmission Pipeline	65-R4	-20	1,371,509,954	11,189,760	263,112,231	6,237,742	0.45	2.03
465.11	Intermediate Pipe - Whistler	65-R3	-20	42,295,869	143,778	8,315,396	167,096	0.40	2.16
465.30	Mains - Mt. Hayes	65-SQ	0	6,307,725	20,156	- 20,156	(310)	(0.00)	1.54
466.00	Compressor Equipment	37-R4	-3	190,510,140	2,625,925	3,089,379	151,163	0.08	2.70
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	-7	5,340,973	11,218	362,650	15,014	0.28	3.40
467.10	Measuring and Regulating Equipment	37-R1.5	-5	62,016,326	488,524	2,612,293	130,075	0.21	3.03
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5	-7	313,344	(689)	22,623	958	0.31	3.23
TOTAL TRANSMISSION PLANT				**1,731,700,735**	**15,203,618**	**280,316,169**	**6,870,505**	**0.40**	

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
DISTRIBUTION PLANT									
472.00	Structures	38-R1.5	-15	25,234,840	198,267	3,586,959	168,079	0.67	3.51
473.00	Services	47-R2	-70	1,160,659,173	22,727,803	789,733,618	29,573,238	2.55	5.26
474.00	Meter/Regulator Installations	20-S0/23-SQ	-20	188,387,340	(7,465,341)	45,142,809	6,437,406	3.42	11.02
475.00	Systems - Mains	65-R2.5	-25	1,427,597,191	22,972,831	333,926,467	8,390,525	0.59	2.21
477.10	Measuring and Regulating	33-R2	-12	143,051,691	2,478,559	14,687,643	803,539	0.56	3.78
477.20	Telemetry	20-R3	-5	14,930,538	18,319	728,208	82,086	0.55	4.79
TOTAL DISTRIBUTION PLANT				**2,959,860,773**	**40,930,438**	**1,187,805,705**	**45,454,873**	**1.54**	
BIO GAS									
418.20	Purification Upgrader	20-SQ	0	9,794,870	20,996	- 20,996	(1,050)	(0.01)	5.00
472.20	Structures and Improvements	36-R1.5	-10	654,898	2,261	63,228	2,705	0.41	4.22
474.10	Meters/Regulator Installations	19-S0	-25	226,054	3,355	53,158	4,683	2.07	9.75
475.10	Mains - Municipal Land	65-R2.5	-25	1,655,815	17,279	396,674	8,066	0.49	2.44
TOTAL BIO GAS				**12,331,636**	**43,892**	**492,065**	**14,404**	**0.12**	
GENERAL PLANT									
482.10	Stuctures (Frame)	25-R1.5	-4	23,263,706	(282,314)	1,212,862	103,544	0.45	4.73
482.20	Structures (Masonry)	60-R2	-4	114,701,266	257,818	4,330,233	110,683	0.10	2.03
484.00	Vehicles	7-L1	15	20,521,572	569,350	- 3,647,586	(1,006,766)	(4.91)	10.82
485.10	Heavy Work Equipment	13-L0.5	5	905,623	1,162	- 46,443	(8,028)	(0.89)	6.44
485.20	Heavy Mobile Equipment	9-L1.5	15	5,384,508	(169,259)	- 638,417	(113,618)	(2.11)	6.39
TOTAL GENERAL PLANT				**164,776,676**	**376,757**	**1,210,649**	**(914,185)**	**(0.55)**	
TOTAL DEPRECIABLE PLANT				**5,117,535,893**	**58,478,752**	**1,505,591,903**	**52,902,383**	**1.03**	

112.2 From page D-16, please indicate and list how many companies FEI, FBC and/or Concentric examined either as an expert witness or through reviewing regulatory decisions related to those utilities primarily have regulatory approval for use of the straight line whole life or remaining life methodology (separately) and the ALG versus ELG procedure for developing depreciation rates and the subsequent depreciation expense. Please indicate for the companies that use the ELG procedure, which ones use option 1 versus 2. Please provide in table format. As part of the response, please also indicate whether the remaining life is based on an ALG or ELG remaining life calculation.

<u>Response:</u>

The following response has been prepared by Concentric:

Concentric had appeared either as a witness or entered testimony for each of the utilities listed in the table below.

Utility	Whole Life (W/L) or Remaining Life (R/L)	ALG Or ELG	Option 1 Or Option 2
Pacific Northern Gas (PNG)	R/L	ALG	N/A
AltaGas Utilities Inc.	W/L	ELG	Option 1
FortisAlberta Inc.	W/L	ELG	Option 1
ATCO Electric	W/L	ELG	Option 1
ENMAX Power Corporation	W/L	ELG	Option 1
ATCO Gas	W/L	ELG	Option 1
AltaLink L.P.	W/L	ELG	Option 1
SaskEnergy	W/L	ELG	Option 1
SaskPower	W/L	ALG	N/A
Manitoba Hydro	W/L	ALG	N/A
Centra Gas Manitoba	W/L	ALG	N/A
Enbridge Gas Inc.	R/L	ALG	N/A
Gazifere	R/L	ALG	N/A
Gaz Metro (Energie)	R/L	ELG	Option 1
NB Power	R/L	ELG	Option 1
NS Power	R/L	ELG	Option 1
Newfoundland Power	R/L	ELG	Option 1
NALCOR	R/L	ALG	Option 1

FortisBC notes that Manitoba Hydro is using ALG for regulatory accounting and ELG with componentization for external financial reporting under IFRS.

112.3 Please provide relevant excerpts from the decision related to the Manitoba Hydro 2014/15 – 2015/16 application as described at page D-18, showing the position of each of the parties involved in the application and relevant excerpts from Commission decision that denied the use of the ELG procedure.

Response:

The following response has been prepared by Concentric.

Please refer to Attachment 112.3.

112.4 Please explain if there is any inherent reason(s) why FEI, FBC and/or Concentric did not examine or expand its research on ELG to include any or all gas pipeline utilities and any electric distribution and transmission utilities.

Response:

FEI reviewed the depreciation method used by other utilities which consisted of a sample of major Canadian gas utility companies as explicitly directed in BCUC Order G-119-16 which stated "*FEI is also directed to include a discussion of the group depreciation method used by each of the major regulated gas utilities in Canada*."

112.5 For either of FEI or Concentric, please confirm that in Alberta, which primarily uses the straight-line whole life method, equal life group procedure for most of the assets of the gas and electric distribution and transmission utilities regulated by the Alberta Utilities Commission. If unable to confirm, please fully explain why not.

Response:

Confirmed by Concentric. In Alberta all regulated utilities with the exception of EPCOR use the equal life group procedure to develop the depreciation rates for the gas and electric distribution and transmission utilities regulated by the Alberta Utilities Commission. FEI also understands that the many of the Alberta utilities have been using equal life group method for many years, similar to how the BC utilities have utilized average life group for many years.

For the qualitative and quantitative reasons described in Section D2.2.4 Average Life Group versus Equal Life Group in Section D2 of the Application, FortisBC is not of the view that it should simply adopt the same depreciation methodologies as the Alberta utilities.

112.6 For either of FEI or Concentric, please explain why there appears to be a "requirement" with the use of option 1 to do annual examinations, as noted in page D-17 to potentially use an adjustment to depreciation expense if there is a variance in forecast and actual retirements. Please also indicate if this "adjustment" is the same as or similar to the annual technical update that has been used in the past for Alberta based utilities regulated by the Alberta Utilities Commission. If this annual examination described by FEI is not the same or similar to the annual technical update used in the past for Alberta based utilities, please explain the difference between the two approaches (i.e. option 1 annual examination versus annual technical update). If the two approaches are different, please explain if FEI or Concentric examined whether a technical update approach could or should have been recommended as part of an ELG Option 1 recommendation for annual review.

Response:

The "adjustment" referred to in Option 1 is the same as the annual technical update that has been used in the past for Alberta based utilities regulated by the Alberta Utilities Commission.

112.7 Please explain why FEI and/or Concentric did not include ATCO Gas (the distribution component of ATCO Gas and Pipelines Limited and largest gas distribution utility in Alberta) in its list of companies shown in Table D2-7.

Response:

This response has been prepared by Concentric.

Exclusion of ATCO Gas from table D-7 was an oversight. For completeness of record, ATCO Gas uses the Equal Life Group Procedure applied on a Whole Life Basis. This ATCO Practice has been approved by the AUC since the 1980's and was most recently approved by the AUC in Decision 2011-450.

113.0 Reference: Exhibit B-1, pages D-23 to D-30; Exhibit B-1-1, Appendix D2, Section 6, Retirement Rate Analysis, commencing pdf page 1032

113.1 **FEI and/or Concentric discuss the deprecation study for FBC starting page D-23 and further the retirement rate analysis in Section 6 shows the retirement analysis and visual Iowa curve reviews.** Please provide all the underlying data used to construct the retirement analysis and resulting Iowa curves in Section 6. Please provide the data in a text and excel file format and include a list of the codes used by Concentric (i.e. addition code, retirement code, adjustment code, whether dollars are shown including or excluding "cents", etc.). Please provide the information in CD format.

Response:

Please refer to Attachment 113.1 for the requested Excel spreadsheet provided by Concentric that was used to construct the retirement analysis and resulting Iowa curves in Section 6 of the FBC Depreciation study.

- Account Number represents the Account Number as used in the development of the Average Service Life and Detailed Depreciation Calculations.
- Trans code represents the transaction type of the specific transaction as follows:
  - "3" represents a transfer
  - "9" represents an addition to plant
  - "0" represents a retirement transaction
  - "8" represents an aged surviving balance as at the date of the transaction year
- Trans Year represents the year in which the transaction was booked in to the plant accounting system. In the circumstances of a transaction type "8" the transaction year represents the year of the aged surviving balance.
- Installation Year represents the year in which the investment was placed into service.
- Amount represents the amount of the transaction
- Adjusted transaction year represent a move of the year of the transaction for life analysis purposes only within the depreciation study database.

113.2 Please indicate if FEI, FBC and/or concentric conducted either a full or partial (of any size) Causes of Retirement Study to help Concentric determine from an objective perspective the reason or cause why assets have been retired in the past. These reasons could include wear and tear, technical obsolescence, acts of nature, municipal and/or government requirements. If study was done, please provide a copy of it. If not, please explain why not.

<u>Response:</u>

There was no full or partial Causes of Retirement Study prepared by either FEI, FBC or Concentric. A cause of Retirement Study would take a significant amount of time and effort and would involve researching each individual account in each year. Since FEI does not track the causes of plant retirements in its SAP system, FEI is not able to provide such information.

Please refer to the response reproduced below from BCOAPO IR 1.10.1 submitted on May 4, 2016 as part of the FEI Proposal for Depreciation and Net Salvage Rate Changes Application.

10.0 Reference: Exhibit B- 1, Gannett Fleming (GF) Additional Evidence, Attachment 2, Group Accounting.

10.1 Starting on PDF page 35 of 73, GF discusses the nature of retirements, including, third party strikes, and forces of nature including storms and soil erosion, and other. Please provide an analysis of all retirements in the study splitting the number of retirements and cost of retirements for each year and each account by each of the causes listed by GF.

Response:

The requested analysis is often referred to as a "Cause of Retirement Study". Provided that the information is available, a Cause of Retirement Study would take a significant amount of time and effort and could not be completed within the time allotted for responding to IRs in this proceeding. Using account 473-00 - Distribution Services as an example, a Cause of Retirement Study would involve researching each individual asset retirement in each year from 1963 to 2014. This would then be replicated for each of the 68 asset accounts studied. Since FEI does not track the causes of plant retirements in its SAP system, FEI is not able to provide such information.

113.3 Please indicate if FEI, FBC or Concentric examined any retirements used for the retirement analysis shown in Section 6 because they appeared to be unusually large or non-recurring and were believed to be unusual or extraordinary. If there was an examination, please provide a copy of the study and/or results including copies of emails and paper discussions between FEI, FBC and Concentric and whether that resulted in certain retirements being excluded from the depreciation study. If there was no examination, please indicate why not and what criteria, if any, would be used by FEI, FBC and/or Concentric to determine if certain retirements should be considered unusual or extraordinary and excluded from a retirement analysis. Please include comments on whether one-time large events (i.e. retirement amounts that are relatively large) that are not expected to recur on a regular basis.

Response:

There was no examination undertaken as described in the IR, and other than noted further in this response, there were no unusual, extraordinary retirements or one-time large retirement events that occurred since the 2014 Depreciation studies were updated for either FEI or FBC. The one exception was the disposition of the Castlegar District Office, referred to in the response to BCUC IR 1.121.1, for which the net book value and proceeds were captured in a deferral account as approved pursuant to Order G-153-17.

113.4 As part of any analysis conducted on the retirements prior to examining the results of the retirement analysis, please explain if FEI, FBC and/or Concentric would have examined retirements caused by wildfires, floods, tornadoes and other acts of nature should be examined and possibly excluded from the depreciation analysis. If not, please explain why not.

Response:

The following response has been prepared by Concentric

FEI, FBC and/or Concentric do not exclude acts of nature from the applicable depreciation analyses. Concentric views that with the increasing frequency of forces of nature events, retirements associated with these events are expected to have a probability of re-occurrence. As such, retirements caused by forces of nature are, on their own, a force of retirement to be considered.

113.5 Please explain why there only appears to be one type of placement and experience band analysis conducted for each of the asset accounts. That is, why were different sizes of placement band analysis conducted? Why were there not different sizes of experience bands examined other than what appears to be full depth experience bands.

Response:

The following response has been prepared by Concentric:

Concentric views that the full depth bands analyzed were applicable for each of the accounts studied and produced reasonable results. As such, subsets of the full depth bands were not required or utilized.

114.0 Reference: Exhibit B-1-1, Appendix D2-2, Section 3.2.2, page 3-3, pdf page 1013 and Section 10, Estimation of Net Salvage, page 10-1, pdf page 1190

114.1 Please provide a copy of all the historical net salvage data used by FEI, FBC and/or Concentric for each asset account in excel format. The information should be provided on CD.

Response:

Please refer to Attachment 114.1 for the requested Excel spreadsheet.

114.2 Please explain if FEI, FBC and/or Concentric examined any net salvage or related retirement entries used for the net salvage analysis because they appeared to be unusually large or non-recurring and were believed to be unusual or extraordinary. If there was an examination, please provide a copy of the study and/or results including copies of emails and paper discussions between FEI, FBC and Concentric and whether that resulted in certain net salvage or related net salvage entries being excluded from the net salvage study. If there was no examination, please indicate why not and what criteria, if any, would be used by FEI, FBC and/or Concentric to determine if certain net salvage and related retirement should be considered unusual or extraordinary and excluded from a net salvage analysis. Please include comments on whether one-time large events (i.e. net salvage amounts that are relatively large) that are not expected to recur on a regular basis. Please include comments on how FEI, FBC and/or Concentric handled net salvage entries with no corresponding retirement entries in the same year or very large net salvage percentages as a result of not all retirement entries being included in the same year.

Response:

The following response has been prepared by Concentric:

FEI, FBC and/or Concentric did not examine any unusually large or non-recurring retirements that were believed to be unusual or extraordinary. Concentric views that all net salvage transactions should be included and analyzed in a net salvage analysis. Concentric utilizes 1, 3, 5 and full depth banding to deal with retirement and salvage entries occurring in different years.

The following response has been prepared by FortisBC:

While FortisBC corroborates that there were no unusual or extraordinary retirements, the disposition of the Castlegar District Office (CDO), referred to in the response to BCUC IR 1.121.1, was not a transaction that will occur on a regular basis. The net book value and proceeds associated with CDO were captured in a deferral account as approved pursuant to Order G-153-17.

114.3 Please explain how FEI, FBC and/or Concentric examined re-use net salvage. As part of the response in part (a) and (b), please separately show entries that would have included re-use net salvage. Please also provide a copy of the accounting treatment for re-use net salvage as applied by FEI and FBC.

Response:

FortisBC provides the following response:

The IR is asking for the accounting treatment for re-use net salvage. However, page 10-1 of Appendix D2-2, 2017 FBC Depreciation Study, states: "In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized". FortisBC generally does not re-use its assets and therefore does not have separate journal entries for net salvage associated with the re-use of assets. Any salvage proceeds received from an asset disposition are recorded against the net salvage account as described in the response to BCUC IR 1.124.3 for the accounting treatment of net salvage.

Concentric provides the following response:

Concentric indicates that there is analysis of all net salvage entries whether re-use or terminal. If large or unusual entries are noticed they are investigated to determine the cause and may result in a possible different treatment in the net salvage analysis and recommendation.

114.4 Please provide a copy of FEI and FBC's accounting treatment for retired items sold to third parties and whether the proceeds are always credited or debited to the accumulated depreciation account (versus some Revenue account) and indicate if there are instances where the proceeds for sale of retired assets are shown as Revenue, what the specific entries were for each year and asset account and the amount of the revenue.

Response:

In the normal course of business, FEI and FBC receive proceeds from the sale of vehicles or proceeds received from scrapped assets. In FEI, it is usual practice to record the proceeds received from the sale of a fixed asset as a credit to the net salvage deferral account. In FBC, it is usual practice to record the proceeds received from the sale of a fixed asset as a credit to accumulated depreciation. Proceeds received from scrapped assets are recorded the same way as proceeds received from sold assets.

There have not been any recent instances of proceeds for sale of retired assets shown as revenue. However there have previously been non-recurring type transactions, which were approved by the BCUC, that recognized proceeds as revenue. Specifically, the sale of assets to municipalities under the Lease-In Lease-Out transactions in 2001 through 2005, and the Lochburn land sale in 2007 and 2008. However these transactions would not be considered asset retirements in the normal course of business.

Please also refer to BCUC IR 1.124.3 for the detailed journal entries related to net salvage activities, including proceeds of disposal, in the normal course of business.

115.0 Reference: Exhibit B-1-1, Appendix D2, FEI Depreciation Study, Page 3-3, pdf page 766; Account 443.05-LNG Plant – Equipment – Mt. Hayes

On page 3-3 of the Depreciation Study for FEI, with respect to the net salvage for Account 443.05, Concentric states in the last paragraph: "As there have been no recorded retirement, there has not been any recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 20 percent salvage rate at this time."

115.1 Please indicate why the net salvage recommended by Concentric for Account 443.05 should not be set at 0% given the lack of any net salvage or retirement data instead of the negative 20% being proposed. If the response is that it is the same as that approved last time, please provide all information related to the approval of the negative 20% from the last depreciation study.

Response:

FEI consulted with Concentric to provide the following response.

Account 443.05 referred to in the IR relates to Mt. Hayes LNG equipment and it is a relatively new account (original capitalization of 2011). As such, there has been no interim retirement activity and thus, no removal activity. Therefore this particular account is different from other asset accounts where the net salvage costs are composed of typically smaller interim removal costs throughout the life of an asset and those retirements can affect the estimate of the net salvage rate over the life of the asset. As this LNG equipment ages, there is an expectation of some future interim retirement and removal activity and there will be final disposal costs at the end of its life. The determined negative salvage percentages of 20 percent are a component of depreciation rates, and are calculated as the expected cost to remove the asset today divided by the cost to install that asset originally. Therefore, if current users benefit from the use of the asset, they should pay their pro rata share of the cost that will be involved in the retirement of the property.

116.0 Reference: Exhibit B-1-1, Appendix D2, FEI Depreciation Study, Pages 3-3 to 3-4 pdf pages 766 – 767; Account 448.20-LNG Plant – Pre-Treatment

On page 3-4 of the Depreciation Study for FEI, with respect to Account 448.20, Concentric states in the last paragraph discussing the net salvage proposed: "As there have been no recorded retirement, there has not been any recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 10 percent salvage rate at this time."

116.1 Please indicate why the net salvage recommended by Concentric for Account 448.20 should not be set at 0% given the lack of any net salvage or retirement data instead of the negative 10% being proposed. If the response is that it is the same as that approved last time, please provide all information related to the approval of the negative 10% from the last depreciation study.

<u>Response:</u>

FEI consulted with Concentric to provide the following response.

Please refer to the response to BCOAPO IR 1.115.1. The previous study recommendation of negative 10 percent was a conservative estimate of future interim and final disposal expectations based on Concentric's judgement.

117.0 Reference: Exhibit B-1-1, Appendix D2, FEI Depreciation Study, Pages 3-4 and 3-5 pdf pages 767-768; Account 448.30-LNG Plant – Liquification Equipment

On page 3-5 of the Depreciation Study for FEI, with respect to Account 448.30, Concentric states in the last paragraph discussing the net salvage proposed: "As there have been no recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 20 percent salvage rate at this time."

117.1 Please indicate why the net salvage recommended by Concentric for Account 448.20 should not be set at 0% given the lack of any net salvage or retirement data instead of the negative 20% being proposed. If the response is that it is the same as that approved last time, please provide all information related to the approval of the negative 20% from the last depreciation study.

Response:

Please refer to the response to BCOAPO IR 1.115.1. The previous study recommendation of negative 20 percent was a conservative estimate of future interim and final disposal expectations based on Concentric's judgement.

118.0 Reference: Exhibit B-1-1, Appendix D2, FEI Depreciation Study, Pages 3-13 to 3-14 pdf pages 776 – 777; Account 478.10-Distribution Plant – Meters

On page 3-14 of the Depreciation Study for FEI, with respect to Account 478.10, Concentric states in the last paragraph discussing the net salvage proposed: "This study recommends maintaining no net salvage estimate. Inclusion of data from the last three years shows a trend to higher positive net salvage rates. The last ten three-year rolling bands are both more positive than one percent, as are the last ten five-year rolling bands. The historical net salvage rate is one percent. Peer utilities have estimates ranging from zero to five percent. Concentric views that it would be reasonable to maintain no net salvage estimate at this time, however, this account requires careful monitoring in the future."

118.1 Please indicate why the net salvage recommended by Concentric for Account 478.10 should not be set at some percentage greater than 0% such as 1% or 2% given the historical indications for FEI are greater than 0% and the peer analysis is between 0% and 5% (with 0% being the lower bound of the range).

Response:

The following response has been prepared by Concentric:

As detailed on page 7-21 of the FEI Depreciation Study, the historical indications are showing a small increase in the recorded net salvage to small positive values for the past three years; however, the indications from 2009 to 2014 were small negative values. As the total value indicates a negative 1 percent, Concentric views that at this time, the current 0 percent is appropriate and will be evaluated at the next depreciation study for possible adjustment.

119.0 Reference: Exhibit B-1, page D-29, Table D2-12 Net Salvage Rates by Asset Class for FBC

Table D2-12 shows the 2014 net salvage percentages and the proposed 2017 net salvage percentages. FBC has not provided any detail about the proposed 2017 proposed net salvage percentages.

119.1 Please provide all justification for the proposed 2017 net Salvage rates for FBC shown in Table D2-12. Please include the historical net salvage (gross salvage and cost of removal) and corresponding retirements by year for each asset account in the table; copies of all correspondence, notes and emails between FBC and Concentric. Please also include Concentric's peer analysis for each asset account and the weighting, either qualitative or quantitative, of each of the historical analysis, FBC operational and management views and peer analysis in forming Concentric's recommended 2017 net salvage percentages.

Response:

The historical net salvage data is detailed in Appendix D2-2 of the current FBC 2017 Depreciation study in Section 7 "Net Salvage Calculations". Discussion of the selection process is detailed in the current depreciation study in Section 10 "Estimation of net salvage". Provided below is the peer analysis prepared by Concentric, as well the interview notes with FBC, which include discussions regarding net salvage.

FortisBC Peers for Salvage

	Currently Approved	Recommended	FortisAlberta	ENMAX	Manitoba Hydro	Northwest Territories Power Corporartion	Yukon Electric Company Limited	Newfoundland and Labrador Hydro
Distribution Plant								
360.20 Surface and Mineral	0	0	0	0	0	0	0	0
362.00 Substation Equipment	(25)	(30)			0		(10)	
364.00 Poles, Towers and Fixtures	(30)	(35)	(45)	(30)	0	(25)	(75)	(20)
365.00 Conductors and Devices	(30)	(35)	(60)			(25)	(80)	(14)
368.00 Line Transformers	(15)	(25)	(5)	(40)			(10)	(8)
369.00 Services	0	0				(10)	(10)	
370.10 AMI Meters	0	0	0	0			0	0
373.00 Street Lighting and Signal Systems	(10)	(15)	(15)		0	(20)	(10)	(6)
General Plant								
391.00 Office Furniture and Equipment	0	0	0	0		10	0	0
391.10 Computer Hardware	0	0			0	0	0	0
391.20 Computer Software	0	0			0	0		
392.10 Light Duty Vehicles	25	15	50	12	20	10	25	0
392.20 Heavy Duty Vehicles	25	15	15	12	7	10	25	0
394.00 Tools and Work Equipment	0	0	0	0			0	0
397.00 Communication Structures and Equipment	0	0	0				0	

FBC Operational Interview meeting notes

I. Generation Assets - Senior Engineer, Generation Assets, Generation

There are four FortisBC regulated hydro generation sites, located within five kilometres of one another along the Kootenay River. Vintages go back as far as 1960 and they undertook an "Upgrade / Life Extension Program" from 1997 to 2013. While procurement started in 1997, rehabilitation began in 1999. The purpose of the program was to modernize and increase equipment reliability and to increase electrical output of the certain units. It was the first major sustaining upgrade since the assets were originally installed. With an appropriate maintenance program, there is no reason to expect that all major components with the exception of Governor and Exciter will not last another 50 years. Governor and Exciter are controlled with digital controllers which will definitely need to be replaced prior to 50 years of service. The next two years have concrete gate work planned.

Currently instrumentation is mostly standardized throughout the plants. Schweitzer -the control system standard. BC Hydro controls the flow rates and Fortis receives revenues as if the generating units are fully utilized.

Account 331.00, Structures and Improvements was changed to 60 - S1.5 to capture more of the interim retirements reinforced in the intervening years since the last study. Salvage costs are increased to -10% and in line with much higher costs of removal due to asbestos removal and risk of contamination. The volatility in the salvage data as well as the apparent gaps between retirements and cost of removal in calendar years represents lag time between when something is taken out of service and retired and when it is ultimately removed in the field.

Account 332.00, Reservoirs, dams and waterways. Some retirements are showing up after 50 years, but these are interim in nature. Some wing dams need replacement in the future. Changing net salvage to -25% is appropriate given the large historic cost of removals. Larger retirements coming up will likely reduce cost of removal as a function of retirements.

Fortis BC Inc. does not have an abandonment retirement obligation (ARO) account and so a net salvage adjustment to depreciation does not present double counting.

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. FortisBC 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.

Account 336.00 Roads, railways and bridges. There are not as many retirements in this account and operations expressed that there were not too many changes that may occur in this account. An R curve with the mode to the right of average life, would likely be more representative that an S, or symmetric curve.

II. Conductors, Devices, Poles and Lines - Manager, Electric Network Assets, Engineering Services

The condition of the poles is checked every eight years, once they are 16 years in service. Condition assessments are visual, and drill tests the bottom portions of the poles. Typically, pole life is 55 years on average. If more than five poles are replaced, it is called a rebuild.

Once they get access to the right of ways, they may choose to replace any conductors that are no longer viable. Conductors are typically 80-year average life (manufacturer's standard). Conductors are strength tested in a lab after a visual check.

There is a gradual program to replace copper # 6 and copper # 8, to copper ASCR # 2 which is safer and has higher conductive capacity. Most of the conductor failures are around the connections to the poles (clamps, eyebolts). There are new materials being introduced in the industry, namely fibreglass cross arms but these come with a high cost. Steel poles are standard for streetlighting. Transmission has some steel poles, but they continue with mostly wood A frame poles while proceeding with testing of some lattice type structures. In all cases, they follow CSA and FortisBC standards which apply to lines 230 kV and above.

Account 355.00, Transmission Plant - Poles, Towers and Fixtures. Shorter lives can occur when they put in temporary services for a construction project but are removed after a few years. That would explain why over 99% of exposures remain after three years. The replacement program goes for a minimum of 40 years. Second generation poles may be poorer quality than earlier vintages. It seems like they are increasing the number of steel stub supports to allow new poles to last as long as the older poles with no supports. This may not be due to service life but rather a more active maintenance program. Poles are not failing as much as the insulators in account 355.00.

Removing a transmission pole can be as little as $1,000 if it is in a convenient location or as much as $8,000 if it is isolated. There was a suggestion of determining constant dollar net salvage to calculate a theoretical cost of removal as a function of retirement.

Account 364.00 Distribution Plant Poles, Towers and Fixtures. Large retirements at ages 53.5 to 56.5 are reasonable and may relate to the feeder lines they had to retire in the Kootenay. The curve estimates changing from R2.5 to R3 may reflect the more abrupt retirements because of the PCB standards for transformers. Data that operations is gathering shows that costs are approximately 15% of original costs on an average urgent pole replacement and approximately 10% on a planned replacement. Salvage costs adjusted to reflect these discussions to -35%.

Account 365.00 Distribution Plant, Conductors and Devices. The data containing the $17.65 million entry that was out of service in its first year of service in 1993 will be sent to Fortis. Fortis' estimate is that only 10% of the conductors were underground and their maximum life was 40 years. Overhead conductors had a lifespan as long as 80 years although the group also includes switches with a maximum 50-year life. It was discussed to try to increase the life estimate to catch the 50-year retirements and not worrying too much about the residual measure.

Account 356.00, Transmission Plant, Conductors and Devices. There are no buried transmission conductors. They have retired a lot of 'hemcor' conductor in the last few years because of handling issues. The manufacturers allow for an 80-year life estimate and Fortis assumes 65 years on average. They have done a lot of retirements in the last few years, especially rebuilding short lines. Based on the better residual measure and to reflect the shorter rebuilds, it was decided to fit a 51-R1.5 for the average life curve. Salvage costs were brought to -30% in keeping with gradual increases from previous approved salvages.

III. Stations Transmission and Distribution - Senior Engineer Station Assets, Engineering Services

The difference between transmission and distribution substation assets is that transmission serves a broader area at a higher voltage. The Generator Step Up (GSU) transformer has the lower voltage side on the generation area and the high voltage side is in transmission area. Station service assets belong to generation even though they are in the same yard as the substation. There is no direct demarcation between transmission and distribution. Some transmission stations have distribution assets.

The average age of FBC transformers is approximately 38 years. The decision to replace a transformer or to repair it is based on a Condition Assent Review and / or Net Present Value Calculations. Transformer lives expectancy is a function of voltage and load levels. Other factors are the maintenance program, the transformer or subcomponent type, manufacturer and the year of manufacture.

Newer transformers are not expected to last as long as older ones. Better, more modern protection and control systems will allow for longer transformer life as they prevent sustained faults. Next year, FBC anticipate replacing the last of the old circuit breakers designed in the 1920s. All FBC protection and control equipment is digital, with only few electronic or electro mechanic relays. Industry is moving toward technology that is more reliable (accurate) but not necessarily designed to last longer.

FBC provides equal attention to transmission and distribution assets maintenance. Operating expenses are reduced with properly directed capital expenditures and by replacing aging equipment or equipment not supported by the Original Equipment Manufacturer (OEM).

New systems and technology do not necessarily add life to the assets. A smart grid may desensitize the system while distributed generation adds direct current which may impact the harmonics at the substation.

As per CIGRe 12-05 survey the rate of failures is uniform for early life assets but then has higher probabilities for greater than 40 years of life.

Account 353.00, Transmission Plant – Substation equipment has a 50-R4 estimated life while account 362.00, Distribution Plant – Substation equipment, has a 50-R3 estimated life. The difference may be attributable to the higher voltages in transmission that have a sharper decline after the average age is achieved.

Account 390.20, Operations buildings.

Buildings were only retired if they had to in cases of issues with a neighbourhood or if they had to expand it and could not find room. Chose to make the average life estimates 50 years.

IV. Roads and trails, land rights - Property Services Supervisor, Governance

The current FBC policy is not to own roads. Where rights are required, Statutory Right of Ways (SRWs) are the preferred vehicle. SRWs are perpetuity agreements which makes them less amenable to a depreciable life. The land rights account will be amortized over the longest life of the accounts. In very limited circumstances, temporary access may be acquired for the construction period.

Some road maintenance will have to be budgeted in order to repair/upgrade roads to meet the needs of the project (construction, condition assessment, rehab or emergency). Depending on the type of road access acquired, there may be some ongoing maintenance contribution required. FBC has managed to avoid this scenario to date but, going forward, it may become necessary. Roads account may either be blended in with cost of the line or land rights or depreciated quicker.

V. General Plant – Asset Accounting Manager

General plant accounts were mostly square accounts, except for vehicles. In the cases of some general plant accounts, there was discussion to explore options as to how to amortize the original costs.

VI. Electric Buildings - Facilities Planning Manager, Facilities

There are a total of 14 sites, and all buildings are rolled into the same account. There are virtually no retirements in this account. The Trail building was purchased in 2013ish and accounts for approx. half of this account. The other half of the assets are related to a bunch of small buildings. There have been retirements in 2017 but there were none prior to that.

The majority of the buildings are masonry and are all smaller than the gas buildings.

The Trail building was bought at 20 years old. It was bought by FBC recently. They leased it as needed for a number of years and then bought it back. It needed a ton of work when they bought it back.

There needs to a way of managing all the assets in both sets of accounts because they are being built and managed under the same philosophy.

We need to look into the breakdown between building classes in FortisBC Electric.

VII. Electric Meters – account 370.00 - Manager, Measurement, Measurement Services

AMI completed deployment last year – early 2017. The oldest AMI meters are 4 years old.

The meters are part of the meter data management system. Usage is tracked and fed into the network operations center. ICON meters.

There is not a sharing of technology and information between the various Fortis Groups.

FBC is a radio frequency based system between meters, and then cellular system between the collectors and the office. It is on a star network. Meters talk to the meters which collect to a central collector and is sent to the customer center in Trail. Even if the system went down, there are data cards in each collector which could be brought back to the office and read. There is no fear that they will need to retire the meters because the technology for the collectors have changed.

Old meters on the electric side were scrapped. There should be almost no meters older than 4 or 5 years old. There are a few customers who opted out of the AMI meters, but they are almost negligible.

All meter bases were inspected and changed out as needed. The intent was to keep the old ones, but some did need to be retired. The bases are owned by the homeowners.

We need to consider the experience bands for this account because anything older than 5 or 6 years old is gone. As of right now there is no retirement history for the newer meters and the account should only have newer meters in it. Legacy meters were all taken out of service and the account is running out over time.

Electric meters follow location life accounting. There is a desire to move to cradle to grave accounting but it is not happening just yet.

The life of electric meters should be a very steep curve. They should last about 18 years with a steep drop off. There is an assumption that the meters should last for the first test period but it will be very unlikely to last much longer than that.

Post meeting notes.

On September 27, 2018, further discussion with Fortis management was able to incorporate the changes to salvage values on the overall deprecation rates. This affected accounts:

- 333.00 Waterwheels, turbines and generators (-25%),
- 334.00 Accessory electrical equipment (-20%),
- 364.00 Distribution Poles, Towers and Fixtures (-35%),
- 365.00 Distribution Conductors and Devices (-35%),
- 368.00 Line Transformers (-25%),
- 373.00 Street Lighting and Signal Systems (-15%),

In addition, Structures, Masonry (390.10) and Operations buildings (390.20) were assessed a -5% salvage in light of recent costs of removal and more anticipated by management.

120.0 Reference: BCUC Information Requests – 107.3 and 107.4; Exhibit B-1, Page C-80 of Application

BCUC Information requests 107.3 and 107.4 request information requests on the impact of the AMI Major Project program

120.1 Please explain if FEI and/or FBC are proposing approval of depreciation rates for AMI for incorporation into FEI and/or FBC's depreciation expense in the event that AMI devices and infrastructure are installed and operating prior to FEI and/or FBC's next rate application and/or next depreciation study.

Response:

Please refer to the response to BCUC IR 1.107.3 for a discussion of the potential impact of a future AMI Application on FEI's depreciation rates.

FBC's electric AMI was completed in 2016 and the 2017 FBC Depreciation study included in the 2020-2024 MRP reflects depreciation rates specific to the capital costs of that project.

121.0 Reference: Exhibit B-1-1

121.1 Please provide a copy of all correspondence including but not limited to notes, minutes, records of discussion and emails between FEI, FBC and Concentric where staff of FEI and/or FBC provide operational and management views on the lives and net salvage expectations for each account included in the depreciation study. Please also include any correspondence from and to Concentric related to the above that provides further context in how Concentric came to its various conclusions regarding depreciable lives and net salvage in terms of the weight Concentric used from the FEI and/or FBC operational and management views

Response:

Please refer to the response to BCOAPO IR 1.119.1 for a copy of the FBC interview notes.

Provided below are the interview notes in regard to the FEI Depreciation study.

FEI Operational Interview meeting notes:

Rates from last study were implemented in 2017. Study was done as at 2014.

Biogas stations are no different than any other stations. They are the exact same assets as distribution accounts.

Account 473.00 – Distribution Services - Assets & Improvements Manager, Engineering Services & Asset Sustainment Planning Manager, Engineering Services

Previously using 45 – R1

Services should have a life that is shorter than the mains. Operations agrees that a service life should be above 50 years, however the financial records indicate services are retired before they are able to reach a 50 years life.

Service lines are replaced upon a) third party damage b) discovery of the service line being in poor condition c) third partly alteration requests. The service are also proactively replaced when mains are done to prevent leaks. These tend to be older assets anyways, typically past 60 years and are done based on the material of the mains.

There are no major trends to increasing gas service line sizes in residential and small commercial.

New services installed are ¾ inch service which is the new typical standard service size for residencies. As homes are getting bigger and the trend is to more gas fired appliances, so a bigger service is needed. There is no difference in the life of services based on the size.

The max life seems theoretically possible.

There are no plastic pipe renewals occurring within FortisBC. There is no cast iron, no early plastics, so there are no large retirement programs on the horizon.

Plastics did not start until 1981.

Mains proactively retired – approx. 7 km per year – the services related to these mains are replaced at the same time. Mains run parallel to the property – as soon as the line branches off to go to the home it becomes the service.

50% steel, 50% plastic.

Move salvage to a -70% which is in line with the ongoing trend of cost of removal activities.

Municipalities have been imposing rules regarding cost of removal – things like must work at night, more flagging, more work is required to replace services as per municipalities. Almost all services are in urban centers. The trend to more municipal rules has been seen since approx. 2010.

Account 475.00 Distribution Mains - Assets & Improvements Manager, Engineering Services & Asset Sustainment Planning Manager, Engineering Services

Mains replacement program – approx. 7 km per year. Ramped up in 2013. This is a proactive program (that was previously reactive in nature) that targets mains that are deemed at risk of leaking due to specific characteristics/attributes associated with them. Older pipe is typically what is being replaced, due to the materials and installation techniques used at the time.

The pipe in this account is about 50/50 plastics and steel. There is no older era plastic pipe in the system. First plastic pipe installation was in 1981 in Kamloops.

Spot repairs (anything less than 6 meters) is typically considered O&M expense, anything more is capital.

The dollars of retirements in this account are pretty much stable long term.

Except for the mains replacement program, most main retirements are driven by third party requirements. Typically - through municipalities wanting to move a road, developers wanting to change the elevation of a road.

Reimbursed retirements – these are accounted through CIAC Distribution account.

Mains are typically abandoned in place.

Account 472.00 – Distribution Structures - Assets & Improvements Manager, Engineering Services

This account includes – buildings and concrete foundations around gate stations and large meter sets, meter protection cages, fences, etc. There is a large variety of assets with differing expected lives. It also includes site costs, security systems, etc.

The variety of asset types in here means that a low mode curves are necessary.

Typically the buildings tend to be framed aluminum side buildings, concrete slabs. These retire due to community aesthetic, some deteriorate due to the atmosphere, station being resized.

Sites are rarely sold but will be done on occasion when absolutely necessary. There may be 1 – 2 in the last decade that were sold.

System reconfigurations have not been such a huge issue in FEI.

There are some underground regulator stations in the lower mainland. These are big steel boxes alongside the roads.

The split between the station buildings and the mechanical components of the buildings are a best estimate of the Project Manager. There is not a concrete formula that is applied to every case.

There are not many retirements to assets in this account other than buildings. These typically get O&M costs.

The buildings are starting to be installed with sound deadening equipment – there is no need to retire due to noise.

The reason FEI is so much shorter than peers is because there is such a huge mix of assets in this account. There is such a densely developed service area that the buildings need to be retired more often due to community aesthetic concerns, the need to increase sizes due to customer demand.

Salvage – there are some years where the numbers are higher due to an incidental write off of a station. It is not unusual to have years with $0 COR and years with much higher COR due to the nature of the assets being retired.

There are very few sites with hazardous materials, it is not common to have to do environmental remediation when retiring. However, it does happen on occasion. The company has always kept the assets in very good shape, there is not a history of old leaky equipment that need to be cleaned up.

Keep the salvage at -15%

Account 477.10 – Measuring and Regulating - Assets & Improvements Manager, Engineering Services

This account includes all the measuring and regulating equipment in the Distribution System. There are no meters in this account, it is purely the equipment.

This account is regulators, valves, line heaters, filters, all the process flow piping. Historically the stations were built with equipment that was needed at the time. Now the equipment is more easily replaceable so there is the ability to size up as needed, and the practice is to build with the intention of being able to expand easily. This extends the life because there is not a need to retire the entire system when a bigger one is needed.

Line heaters – FBC has tried many different types of heaters to find one that works best. There is not a single type of heater that has worked well everywhere. These tend to be approx. $100-200K to replace. There are hundreds of line heaters in the system.

This account could continue to slowly stretch out over the foreseeable future. The future should continue to mirror the history.

The COR for this account is going in and taking out the actual equipment. Working in a very urban station would cost more than retiring in more rural areas. It is expected that the removal costs would be fairly low because most of the cost would go to the new equipment. There have been a few bigger retirement programs due to retirements associated with removing an entire building. 2016-2017 costs are most like what we expect to see in the foreseeable future.

Account 477.20 – Distribution Telemetry - Assets & Improvements Manager, Engineering Services

This is mostly just data going out, there is not a distribution SCADA system. Sensors and devices that allow data to leave a gate station site. This is mostly alarms and data collection systems to proactively deal with issues. Most is on regulating system assets and city gate systems.

There are no lease costs for access to the communication path. Equipment in this account. The paths are accounted for in O&M.

The telemetry systems are being installed to make it cheaper and easier to do upgrades as needed. The buildings and systems themselves are being built better and can be expected to last longer, however the technology part is seeing a shorter life.

This account likely includes the RTUs, the PLCs, etc. The life cycles on these assets are much shorter than they were even a few years ago.

Sensors are run to fail, these last much longer than the other assets in this account.

Run the experience/placement bands post 1994 for this account.

Account 476.00 – NGV Fuel - Assets & Improvements Manager, Engineering Services

Keep the same

Account 478.20 – Instruments - Asset Accounting Manager & Manager, Measurement, Measurement Services

This account is the signal sender for the meters for commercial and industrial clients

Account 467.20 – Transmission – Telemetry - Assets & Improvements Manager, Engineering Services & Gas Control & SCADA Manager, Energy Supply

This is the SCADA account. This is really both; simple telemetry and SCADA. Telemetry being a information gathering system while SCADA being the ability to take the data, analyze it and then make changes to the operation of the system. Thus most work/devices undertaken in the field is deemed to be telemetry while the work/devices/equipment in Gas Control is referred to as SCADA. This account includes the control room in its entirety, including software and hardware.

The control room is currently being expanded to facilitate increased staffing levels, and includes an enlarged footprint as well as peripheral equipment. The SCADA system is also being replaced and expected to be online in late 2019; the last replacement was done in 2010 so the life cycle is about 8-9 years, however at the current pace of technology this is expected to grow shorter as we go forward. These changes are driven by technology obsolescence (both hardware and software), increased security measures, industry best practices, and moving towards alignment with industry regulatory benchmarks that currently exist in the U.S.

The new software is Honeywell.

The control room uses WAN, wireless cell systems, dial up phone systems, long and short range radios for communication between SCADA and field devices. FBC owns most of the hardware to these communications but bandwidth is provided by third-parties.

Technological changes are driving lives shorter. The cell phone systems are currently operating on the 4G platform. In recent years FBC has diversified its use of wireless communications with multiple service providers to provide redundancy, so that in the event of a loss of one provider's network will not cause a system-wide communication blackout.

The remainder of the cost in this system are the field assets that communicate with SCADA; these include Remote Terminal Units and communication modems installed on site. These equipment relay statuses and information of individual stations to SCADA and allows real-time monitoring and control of FBC assets. Operators in Gas Control constantly monitor this information, and respond to alarm conditions and system warnings. Due to the complex possibilities behind alarm conditions, human interpretation and intervention are desired and the system is specifically designed that way; automatic "smart" responses require programming logic that cover numerous possibilities, and in FBC's experience is practically impossible to achieve without introducing substantial risks.

There is not full implementation of remote valve opening/closing – there are still a large number that require manual opening/closing. When moving manual valves to remote operated, the entire valve doesn't need to be replaced; existing valves can be retrofitted with actuators and ancillary equipment to enable remote operation, as well as potential addition of power and communications if these do not already exist at each location.

The SCADA system is capable of 2 way communication. Inbound traffic receives information from field devices as described above; outbound traffic allows Gas Control to remotely operate compressor stations, flow control valves, mainline valves, and odorant systems.

Through the SCADA system FBC is able to monitor gate and building security, as well as fire alarms, hazardous H2S concentration alarms and Emergency Shut Down alarms at select sites. These include compressor stations, LNG sites, and transmission stations.

Odorization is monitored and controlled at custody transfer locations with interconnecting pipelines, to ensure that proper odorant is injected. All gas receipts into the FBC system are odorized this way.

Sending/receiving devices located on the actual equipment – some are capitalized as part of the equipment, but some others are part of the telemetry equipment. If the equipment comes with the telemetry equipment already attached then it is part of the equipment account, if it is purchased separately then it is part of the telemetry account.

The SCADA equipment and communication channels are not run to failure. However many telemetry sensor devices are. Control devices on equipment that responds to a command from Gas Control would not be run to failure if they require reliability. The control device would always be part of the equipment

The majority of the expense in this account is the SCADA system, which is replaced every 8-9 years or so but as noted above, SCADA system life cycles are declining due to rapid technology changes.

Replacement of the Control Room does not require hardware change in the field typically. There are some assets that will need to be replaced (ie dial up may not be carried by the SCADA control room systems in the next go round).

This account may need to be cleaned up as there may be assets in the data that should be retired.

Check EGD for the peer analysis

COR – There is not a history of positive or negative COR in this account.

Account 468.00 – Transmission Communications Equipment - Assets & Improvements Manager, Engineering Services & Gas Control & SCADA Manager, Energy Supply

There are some towers which are owned and some are leased.

Digital radios – Planning on using them going forward, no plans to eliminate the radios.

Towers are typically in remote areas and have a longer life than the other assets in this account.

The radios in here are both fixed and handheld.

The 19 year life is about right on this account.

There is no positive salvage on this account. By the time it is retired, there is no value left in the equipment.

Account 462.00 – Transmission Compressor Structures - Assets & Improvements Manager, Engineering Services & Specialist Engineer, Plant Systems, Engineering Services

There are 8 compressor sites on the mainland and 3 on the island. Each site has multiple buildings, some sites only have single unit.

We will be touring a compressor site tomorrow at Langley.

They are large aluminum sided or galvanized steel buildings with concrete pads. Steel beam inside. There are channels on the concrete so that the pipes can run under the floor. If a site is decommissioned, then the site would be demolished. If it is replaced with another compressor package, then the site remains but modified to fit the new equipment. If it is sold, then nothing changes as it would probably be sold as is. A site hasn't been sold in a very long time. There are also environmental concerns regarding the land underneath the buildings. There are no functional basements on site. Site has secondary containment where required and managed responsibly.

The buildings do not require a ton of maintenance. They are large well-built structures which don't need a ton of work to maintain. The auxiliary equipment such as cranes, and large equipment in the buildings are considered part of the structure account. This equipment was typically added later and has likely not had a full life cycle yet.

There are a lot of HVAC, fire detection systems, etc that need to be replaced and repaired on a fairly regular basis. There is currently a more efficient electrical lighting system being implemented, and the fire suppressor systems are being upgraded or added for the first time. The new fire systems will likely have foam and nitrogen suppressors.

Maintenance items are O&M and upgrades are capitalized. There are currently no plans for major refurbishment in the foreseeable future, though there are plans to add fire suppression systems.

No environmental concerns with these buildings.

Keep this account to a 30-R4. Leave the salvage at -3.

Account 463.00 – Measuring and Regulating Structures - Assets & Improvements Manager, Engineering Services

These are TP/TP stations; Lower Mainland – 4 (75% have structures). Vancouver Island System – 20 (all the former PCEC stations, all have structures) Interior - 12 (50% with structures). The life on this should be similar to the compressor structures. Transmission changes have historically followed a 20 year trend, major changes have occurred approx. every 20 years. That may mean that there may be changes coming up in the next few years.

Make the salvage -15%

Account 464.00 – Other Structures - Assets & Improvements Manager, Engineering Services

This account is the fencing, landscaping, small buildings associated with a transmission line. It is the miscellaneous expenses that go with the buildings. Mostly fencing.

Leave this account where it is.

Account 466.00 – Compressor equipment - Assets & Improvements Manager, Engineering Services & Specialist Engineer, Plant Systems, Engineering Services

No recip units, all have been retired by now. All compressor units are electric and gas turbine fleet now. There was a big retirement in Coquitlam #1 (went from wet seal units to dry seal units) which required an entire compressor change. Units are maintained at 5K hours. 40 years seems about right as per SME for a life estimate.

There should be some negative COR for this account, but it shouldn't be a huge amount. -3 is about the right account.

Major overhauls are done based on manufacturer's recommendation – typically at 30K hours.

The smaller ones are not capitalized but the major ones are. These are done based on the individual unit, there is not a set schedule. However a logical average would be about 5 years.

Inspections – every 7 – 10 years all assets are dealt with, accounted for in a separate account.

Account 467.10 – Measuring and Regulating Equipment - Assets & Improvements Manager, Engineering Services

Use 37-R.1, good residual measure but not as much of a change in life.

This is where gas is taken from very high transmission pressure (ie from a source gas line) to the normal operating pressures. Many of these act like distribution gate station, where they limit or reduce the downstream gas pressure. The 37-R1.5 makes sense.

2016 & 2017 legitimately do not have COR

Make this account -5%

Account 484.00 – Vehicles/392.10 Vehicles (Electric) - Manager, Fleet Services, Safety, Training & Fleet

Policies are very similar between gas and electric for vehicles, maybe less so for the heavy and light power operated equipment.

The replacement policies were rewritten approx. 5 years ago to be the same across FortisBC.

Replacement policies fell behind as the PBR period happened. General Plant assets were not targeted for replacement unless really necessary. The change in the Canadian dollar also has really impacted the ability to replace vehicles as needed. When the dollar was over par there was more budget to replace units, given that it is currently way under par there are simply fewer dollars to spend.

Vehicles include any type of vehicle, regardless of weight. From cars, half tons, one tons, a tractor, etc. for gas. There are break outs between light and heavy duty for electric company.

We need to look into the electric retirements to ensure that all the proper retirements are being done. We should only look at the last 5 years of experience for the retirement rate analysis.

Vehicles are budgeted to be replaced every 7 years or 200K Km.

All replacements are evaluated on an individual basis, feedback from end users and CVIP safety inspections are used to determine if any trailers need to be replaced. They are only replaced when necessary. They are part of the heavy duty group for electric and the light duty for gas.

Electric – move to an 8 or a 9 year life.

Gas – 7 years sounds right.

The salvage costs associated with this account are for both the owned vehicles and leased vehicles. When a leased vehicle is retired, any amount of gain on the lease is recorded in this account but the retirements are associated with only owned vehicles. This is how we have years where the salvage amount is more than the amount retired.

Make the salvage +15%

Heavy Work Equipment – 485.10 - Manager, Fleet Services, Safety, Training & Fleet

These are heavy work equipment such as tractors, bobcats, etc. assets are replaced as required, there is no firm replacement policy.
This is kind of a miscellaneous account – stuff that doesn't fit in 484 or 484.20 goes in here.
The 13 year life makes sense for this account.
There is no expectation of salvage for the assets in this account. The equipment is used to failure so there is no value left in them. Make +5% salvage to account for some small dollars that are received.

Heavy Mobile Equipment – 485.20 - Manager, Fleet Services, Safety, Training & Fleet

Backhoes, John Deere, etc

There has been an increase in the maintenance costs because the guys use these as much as possible. In the interior a 10 year life is reasonable, but in the lower mainland they are used far more because the weather is warmer and they can work year round.

Make this account a 9 year life.

There haven't been any sales in this account so there are not any historical calculations. Expect to see about 15 – 20% positive salvage

Account 430s – Manufacturing Plant - Assets & Improvements Manager, Engineering Services

This is the Revelstoke propane site. Propane is purchased and transported in by train, or truck. This system is 100% propane system. There is no compression here at all. It is part of the distribution system.

The last work was done in 2010. Towers are in structures. Piping is equipment. Tanks are in equipment. Line heating is in equipment. Holders are tanks – these are 60 foot bullet tanks.

Structures seems right at 40 years.

Equipment – 20 years seems about right.

Holders – 40 years seems about right.

Compressor Equipment – 25 years seems about right.

Measuring and Regulating Equipment – 20 years seems about right.

IT Assets – Gas and Electric assets - Director, Infrmtn & Infrastrut Security, Information Systems

Hardware – Still own all equipment, no leases anymore even for printers

Computers are replaced about every 4 years, desktops are slightly longer, laptops are slightly shorter

Tablets are a small amount of hardware (2-3%) but do not last as long.

Cell phones are included in this account – only last about 3 years.

Printers last about 5 years.

Monitors in the conference rooms are large monitors that last at least 5 years.

4 years is more reasonable for hardware accounts because there has been a huge move away from servers and to portable devices.

Has moved to cloud based servers where possible. 5-8 year plan to be 50% cloud based.

Accounting principles are slowly changing to allow cloud based assets to be capitalized.

There is no directive to match Fortis Inc policies for IT policies.

ERP systems are 8 year assets. Only large software packages.

GIS should be 8 year asset.

Billing is SAP on gas, CIS Plus on the electric side. Both get full reimplementation every 8 years. Systems are completely retired and then reissued at 8 years.

Application software (Microsoft, Sharepoint, etc) – are 5 year assets.

General Plant Structure - Facilities Planning Manager, Facilities

Buildings, framed or masonry. Includes head office, service centers, offices, contact centers, warehouse, muster, any non-plant type building that staff are housed in. More for human comfort than for equipment. List is the same for gas and electric. Assets are managed similarly but will not have the same life.

Large buildings – corporate office buildings. There is constant movement, particularly on the gas side (because it is a more centralized group). Constant renovations need to fit more people in the space. Infrastructure additions are capitalized when appropriate.

Newer buildings are being built on a partition system so that renovations are easier. No plans currently in consideration to move to a hoteling system where people are without a dedicated desk.

Currently – Kootenay's just built a new electric building. Kelowna needs a new building but it is still a couple of years away from being resolved. Lower mainland sites are getting to capacity, but it will be a few years away yet. There are 3 contact centers – Willington is leased in Burnaby, Prince George is Owned, ¾ of a floor in Trail Esplanade. Willington may eventually migrate to an owned facility but it is still a few years away yet.

Yards – There are no major concerns with soil contamination. There is a potential for something undiscovered yet, but it is not something that is a high risk by any means.

Account 482.10 – Frame Buildings - Facilities Planning Manager, Facilities

The major retirement at age 12.5 was the retirement of two separate buildings to move into the current Surrey building. The older buildings were demoed because they had significant structural issues. They were located on a bog and the pilings were sinking.

The older buildings would have been expected to live for 20 years. They were not being built as well, they were often on a double wide trailer type base. The current expectation is that assets being built today are being built better. This will extend the maximum life of the building however there is still a lot of interior renovations that need to occur in order for the building to survive. Things like HVAC systems, carpets, windows need to be replaced regularly for basic maintenance.

This needs a 25-R1.5 with -4% salvage.

The salvage amount in 2015 and 2016 relates to some cleanup of assets between masonry and frame. There were some retirements in Fort Nelson and Burnaby that relate to building retirements. The buildings are getting to an age where they need things like roof replacements, windows replacements, etc.

Account 482.20 – Masonry Buildings - Facilities Planning Manager, Facilities

These are bigger buildings, such as head office. There is a $52M asset at 2005 – that was the Surrey and Burnaby purchases.

Current buildings are lasting longer because they are more utilitarian design. The concrete finishes lasts longer.

This should be a 60-R2 to account for a higher level of interim retirement. COR at -4%

The economic life of buildings – There is currently a building that is approx. 90 years old. It is way past its prime and it is time to let it go. Code changes have rendered it unusable practically.

Account 483.30 - Facilities Planning Manager, Facilities

Includes the odd fax machine, shelving, older IT equipment (like large monitors), fridges and stoves, fitness equipment.

15 years is about right.

Account 483.40 – Furniture - Facilities Planning Manager, Facilities

Chairs do not last nearly 20 years, but it is offset by conference tables, desks, etc that last at least 20 years.

Keep this account at 20 years and check it again in a few years to see how the newer stuff is working.

Account 465.00 – Transmission Mains - Assets & Improvements Manager, Engineering Services & Manager, System Integrity Programs, Integrity Management

Transmission system is completely steel (100%). It is all cathodically protected using anode bed, rectifier, or anodes. All is coated.

1950s lower mainland – coal tar enamel, interior is asphalt enamel

No issues with hand wrapped joints. There is a lot of hand wrapped or shrink sleeve joint coatings in the system and as of right now there have not been any problems. The primer is holding up well.

The largest size is 42", to ¾" at the smallest.

Internally anything over 2100kPa (300psi) is currently tagged as transmission, regardless of what size or material the pipe is made out of.

The larger pipes are pigged down to most 8" pipes. Trying to convert all 6-8" pipes to ILI capable. Part of the problem is that not all the pipes have enough pressure to move the pigs through them effectively. Working on a plan to get all pipelines are pigged every 7 years. Anything over a 30% stress level needs to be pigged on a recurrence based on the condition of the pipe. Right now anything over 30% is inspected or mitigated by some way (digging in, replace the pipeline, reducing the pressure). Almost all of the pipes that are being replaced are approaching or exceed 61 years old. 100s of meters at a time are being replaced. There is also an issue with the number of people living in areas with transmission pipes – in order to maintain the design safety factor the pipes need to be either lower pressure or replaced. Because new homes require more pressure it makes more financial sense to replace the pipes than to turn down the pressure.

The 70-R3 seems to be the right estimate according to SME, though 65-R4 is a better fit.

There has been some work on the older valves, approx. 1957s era.

2009 – 2011 was retirements on newer pipe in a very costly area. There was a new highway being built over a newer pipe which required very costly line moves. The ground was difficult to work in and this drove costs way up.

The cost to retire pipe is very dependent on the location of where the pipe is. If it is being retired in an expensive area that requires pipes to be completely removed then this costs way more. If it can be abandoned in place then it is far cheaper.

There are a very small amount of pipes (about 200m) that are subject to LMCI. This is such a small amount that it is not a concern.

Thus far the majority of retirements are interim retirements. There haven't been any terminal retirements yet.

Keep the salvage at -20%

There is an upcoming study to figure out how to change the operating pressure easily to account for raising and lower the pressure as needed. This may be a large expenditure but has not been approved yet.

Still in talks with the plant at Woodfiber. The owner and FBC are in discussions to figure out if the plant will go forward. LNG plants were initially built as peak shaving plants. The mainland facility is now used for trucks. FBC fuels the BC ferries fleet. Mt Hayes plant goes predominately to the ferry terminal.

Distribution Meters – Account 478.10 - Manager, Measurement, Measurement Services

Electric meters are really new, the AMI program went into place 3 years ago.

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.

Electric seal periods – 10 years, 8 years, 6 years. This is after conditional approval.

FBC 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

The subject matter expert believes that the 18-R2.5 is a reasonable life. 1% salvage is reasonable for this account.

Account 474 is for the installations and removal of meters. Any COR is recorded in this account.

Meters are scrapped when they are taken out. They are not allowed to resell them as meters, however they do have scrap value.

Bigger meters do have a longer service life. There are approx. 8,500 rotary meters and cost $3K each. The turbine meters are 300-400 and cost approx. $25K. Approx. 90% of the meters are residential, so these are a tiny fraction of the original cost in this account.

The meter readers use ITRON guns that read the meters. There are a handful of customers that have inaccessible meters and there is an ITRON ERT that sends the meter read to the gun. There is currently no plan to go drive by meter reading at this point.

Gas meters follow cradle to grave accounting.

There has been a change in how residential meters are installed. Meters are installed with a bicast valve so that they can be replaced without any interruption to customers at all.

Account 474.00 – Meter/Regulator installation costs – Asset Accounting Manager & Manager, Measurement, Measurement Services

The cost of removal should be compared to the actual cost of the meters. The retirements are taken out over a 20 year life and are retired on a SQ curve. The COR has no relation to the actual dollars retired out the account. The COR are all abandonment costs, there are no install costs embedded in. The COR needs to be booked against this account, it does not fit in the 478.10 account as the 478.10 account is purely the actual physical meter. The 474 account is the actual labour for meters. We need to add the retirements for 478.10 and 474.00 to get the retirements for the 474 COR calculations. Account 474 needs to be amortized. Should be amortized over 20 years.

BioGas assets - Manager, RNG, NGT & Regional LNG

Raw gas comes out of a landfill/wastewater treatment plant/agri waste. Has a low heating value. It goes through the upgrader and has a high heating value. The output product is pure biomethane (called "renewable natural gas" in FBC but call it biomethane in report). Interconnect station looks like a typical distribution compression/regulation station. It is a collection of pipes, meters, regulators, etc with extra monitoring. It connects from the interconnect system into the normal gas stream. The collection assets to collect the raw biogas is owned by other entities.

First assets went into service in 2010.

Upgrader compresses, removes contaminants (water, etc). It looks like a smaller version of a purifier plant from an LNG. Typical scrubber.

There are currently five biogas stations in service. BCUC has given an allowance of up to 5% of all gas can be biogas due to rate constraints. There are no plans to move to this many biogas stations as the cost would be prohibitive.

Using biogas does not dilute the typical natural gas. The molecule is the exact same.

Contracts for the plants are 20 years typically, except Surrey which is 25 years.

There is no reason why these assets should have lives or curves that are any different from the same assets in different groups.

The assets are most similar to distribution, not transmission. There are mains up to 4" (plastic in most cases) but they are considered distribution.

Costs to remove will be lower because they are skid mounted and easy to move. The COR should not match the comparative assets in distribution.

Post meeting notes.

Account 449.00 –LNG – Other equipment – Asset Accounting Manager & Specialist Engineer, Plant Systems, Engineering Services

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.

Attachment 1.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 23.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 29.1

1.4.1 Overview of O&M Savings

In 2018, FBC is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $1.0 million lower than the formula amount. 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 the cumulative formula O&M savings to the end of 2018 that are shared with customers total to approximately $6.1 million, and the cumulative PIF savings to the benefit of customers total to approximately $2.8 million.

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

	Actual	Formula	Variance	1.03% PIF
2014	$ 52.0	$ 52.7	$ 0.7	$ 0.5
2015	51.9	53.0	1.1	0.5
2016	51.8	53.6	1.8	0.6
2017	52.5	54.1	1.6	0.6
* 2018	53.8	54.8	1.0	0.6
Cumulative Savings			$ 6.1	$ 2.8

In 2018 FBC continues to be faced with the 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. As a result, the 2018 projected O&M savings of $1.0 million is lower than recent years, recognizing the impact of the PIF factor in the allowed annual O&M funding available. Contributing also to the productivity challenge are new cost pressures the Company is experiencing.

1.4.2 Initiatives Undertaken

The following are updates to the efficiency and cost savings examples discussed in last year's Annual Review and new opportunities initiated recently.

1. ***Sharing of Gas and Electric Contact Centre Staff***

   In 2018, FBC continued to leverage gas and electric contact centre staff to achieve three goals: to reduce operating costs, to maintain or improve service levels to customers, and to provide learning and development opportunities for staff.

   In total, the integration of activities is forecast to produce annual savings for FBC of approximately $0.300 million.[4]

[4] This may fluctuate slightly year to year depending on the number of electric calls answered by representatives in Prince George.

2. Interactive Voice Response Enhancements

In 2017, new functionality was introduced into the Interactive Voice Response (IVR) system in support of self-service channel options for customers. Basic transactions including obtaining the due date and the balance due as well as the amount and date of last payment are now available for customers 24 hours a day, 7 days a week without the need to speak to a representative. This new channel is more convenient for customers, and will reduce operating costs in the contact centre starting in 2018. The estimated annual savings are approximately $0.055 million.

3. SAP Integration

SAP Integration is an initiative to integrate the FBC and FortisBC Energy Inc. (FEI) SAP systems, moving towards a common SAP platform for both companies. It primarily includes the integration of the Human Resources, Supply Chain, and Finance systems in SAP. The benefits will include a simplified support model, alignment of processes, simpler business processes (i.e. employee expense processing and single sign-on), reduced licensing costs and integrated payroll. Reduction in support costs will be achieved through reduced annual contractor costs because internal resources will be able to displace the contractor support due to the simplified support requirements.

The project is in progress, with completion expected in the third quarter of 2018. The total cost of the project remains on budget, estimated at $4.5 million. Based on the number of employees between the two companies which is currently projected at approximately 77% FEI and 23% for FBC, approximately $3.5 million of the implementation costs will be allocated to FEI with the remaining $1.0 million to FBC. Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million in FBC. The savings will start being realized in 2019.

4. Advanced Distribution Management System

This project implements an Outage Management System (OMS) and replaces the existing Dispatch system with a Mobile Workforce Management System (MWM), enabling the Company to improve its outage response through fault location prediction using customer calls and AMI meter messages, as well as update outages from the field using the MWM. Customers are provided with access to an outage map that is updated automatically from the OMS. The project was completed in late 2017 with benefits including streamlining of the manual outage management processes and the manual dispatch processes, with estimated annual savings of $0.2 million starting in 2018.

5. Redesigning FortisBC Website

FortisBC is redesigning its website (www.fortisbc.com) in order to meets its evolving business needs and the needs and expectations of its customers. Redesigning the website by changing the functionality to be more task oriented will enhance the service

Attachment 41.1

FORTISBC INC.

Compliance Filing G-246-18 March 15, 2019

Section 11
Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Reference	2014	2015	2016	2017	2018	2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Cost Drivers for Formulaic Capital and O&M**								
2	CPI		0.473%	0.879%	0.980%	1.627%	1.979%	2.345%	
3	AWE		2.277%	1.646%	2.050%	1.250%	1.473%	2.646%	
4	Labour Split								
5	Non Labour		45.000%	45.000%	45.000%	45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	55.000%	55.000%	55.000%	55.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	1.465%	1.301%	1.569%	1.420%	1.701%	2.511%	
8	Productivity Factor		-1.030%	-1.030%	-1.030%	-1.030%	-1.030%	-1.030%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.435%	0.271%	0.539%	0.390%	0.671%	1.481%	
10									
11	Average Customer Growth		0.326%	0.181%	0.613%	0.494%	0.629%	0.888%	
12	Inflation Factor	(1 + Line 9) x (1 + Line 11)	100.758%	100.452%	101.155%	100.886%	101.304%	102.382%	

Attachment 65.1

FILED CONFIDENTIALLY

(Provided in electronic format only due to document size and in order to conserve paper)

Attachment 66.1

FILED CONFIDENTIALLY

(Provided in electronic format only due to document size and in order to conserve paper)

Attachment 66.2.1

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(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 66.3.2

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(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 66.4.2

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(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 66.5

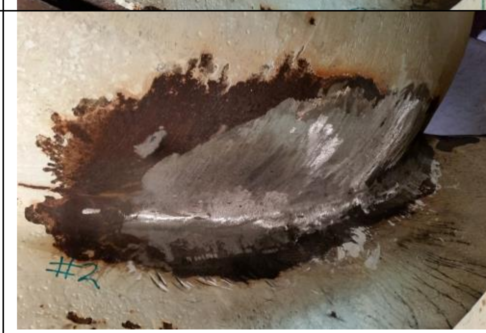
FILED CONFIDENTIALLY

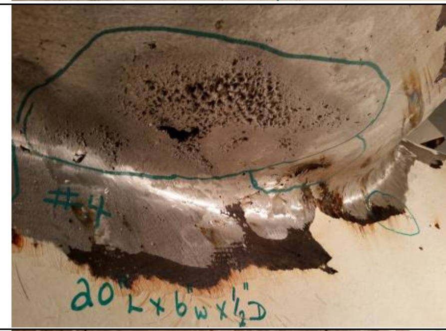
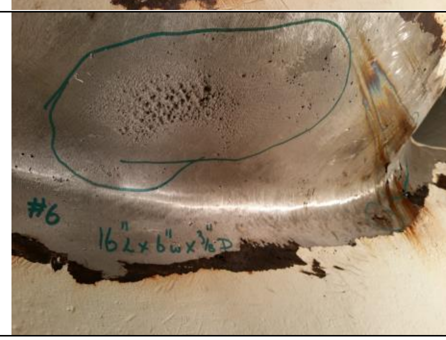
(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 68.1

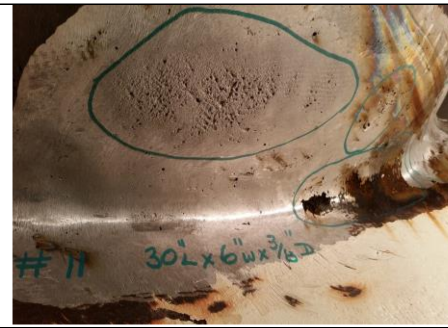
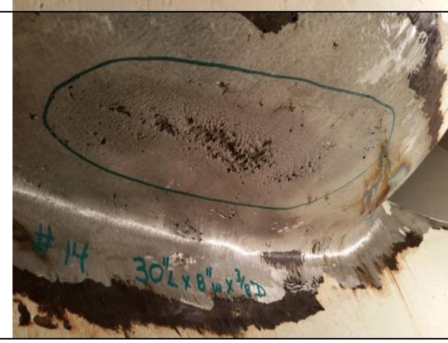
RUNNER INSPECTION P1 – P6 & P11		**JOB PLAN:**	**0300**
Date:	March 14/ 2017	Repetitive Job #	8133
Plant: 2 UBO	Unit: #6	Job Order #	115364

Number of Blades:______15____

Bucket	Comments (Current Condition)	Images (Prior to repair)	Images (Post repair)
w = width l = length d = depth			
#1	-Cavitation in Area A-B-C 8"w x 30"l x 3/4"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Hole in Area A-B 1"w x 1"l x 1/2"d (left as is) -Cav on vent edge 1/2"w x 12"l x 1/8"d (left as is)		
#2	-Cavitation in Area A-B-C 8"w x 30"l x 1/2"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Hole in Area A-B 1"w x 1"l x 1/2"d (left as is) -Cav on vent edge 1/2"w x 6"l x 1/8"d (left as is)		

#3	-Cavitation in Area A-B-C 6"w x 30"l x 3/4"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Hole in Area A-B 1"w x 1"l x 1/2"d (left as is) -Cav on vent edge 1/2"w x 3"l x 1/8"d (left as is)		
#4	-Cavitation in Area B-C 6"w x 20"l x 1/2"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		
#5	-Cavitation in Area A-B-C 8"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 3"l x 1/8"d (left as is)		
#6	-Cavitation in Area B-C 6"w x 16"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Hole in Area A-B 1"w x 2"l x 1/2"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		

#7	-Cavitation in Area A-B-C 6"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 3"l x 1/8"d (left as is)		
#8	-Cavitation in Area A-B-C 6"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 6"l x 1/8"d (left as is)		
#9	-Cavitation in Area B-C 6"w x 20"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		
#10	-Cavitation in Area A-B-C 6"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		

#11	-Cavitation in Area A-B-C 6"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		
#12	-Cavitation in Area B-C 6"w x 20"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 12"l x 1/8"d (left as is)		
#13	-Cavitation in Area A-B-C 8"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Hole in Area A-B 1"w x 2"l x 1/2"d (left as is) -Cav on vent edge 1/2"w x 2"l x 1/8"d (left as is)		
#14	-Cavitation in Area A-B-C 8"w x 30"l x 3/8"d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2"w x 3"l x 1/8"d (left as is) -Cav on vent edge 1/2"w x 8"l x 1/8"d (left as is)		

#15	-Cavitation in Area A-B-C 8”w x 30”l x 3/8”d -Cavitation was ground out to clean metal with grinder after carbon arc gouging, welded with Nitronic 60 to be above surface and finished ground to a smooth profile. Some weld marks remained due to time constrictions. -Cav in Area A-B 2”w x 3”l x 1/8”d (left as is) -Cav on vent edge 1/2"w x 12”l x 1/8”d (left as is)		

Comments/Recommendations:

Cavitation was repaired on low pressure side of all 15 blades using Nitronic 60 as filler material. . Total Nitronic used on this outage was 89 lbs of.030 wire. Turbine was repaired to a mediocre standard that will facilitate extra resources at the next scheduled runner weld. Cavitation at area A-B was not repaired on all blades and small holes in some blades were also left. These were not addressed due to safety concerns and time constraints. Next runner weld, time will be required to build a platform to access these locations safely from the top. Vent edges also require repair and require additional time to complete. Grinding finish was fair with some weld marks remaining due to time constrictions. Draft tube liner and hooks are in good condition. Base ring, wicket gates and scroll case have no visual issues other than where penstock meets scroll case there is a gap. Pics are on G> Generation> Pictures> P2 Inspection Outage Pics> 2017 Unit Outages> P2 G6 Mar 2017 Runner Weld

Was runner deck installed? ☒ Yes ☐ No

Runner deck condition: Mid-section pieces of deck were inspected by WK, CM in February 2017. Mid brace supports were cracked in several locations and were repaired before use. Outer P2 pieces are in need of having the wood replaced in the future. Visual inspection was done and no other abnormalities were found. Installation of deck required that the chain length be 37 links of Grade 8 chain with ring and hammer lock attached for G6.

Compare runner condition against previous report, describe wear increase over time:

Runner requires repair every two years and cavitation is aggressive. The 2014 runner weld was done with only one shift of 4 workers and a watch and upper cavitation was left making the erosion worse at this runner weld.

Sign Off:

FBC Tradesman ____________________________ Date: ______________ FBC Engineer ______________________________ Date: ______________

Attachment 72.1

FILED CONFIDENTIALLY

(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 73.2

FILED CONFIDENTIALLY

(Provided in electronic format only due to
document size and in order to conserve paper)

Attachment 74.1

FILED CONFIDENTIALLY

(Provided in electronic format only due to document size and in order to conserve paper)

Attachment 112.3

M A N I T O B A	)	**Order No. 73/15**
	)	
THE PUBLIC UTILITIES BOARD ACT	)	**July 24, 2015**

BEFORE: Régis Gosselin, B ès Arts, MBA, CPA, CGA, Chair
Richard Bel, B.A.,M.A.,M.Sc., Member
Hugh Grant, Ph.D., Member
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Member

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2014/15 and 2015/16 GENERAL RATE APPLICATION

Manitoba Hydro recommended that the Board should consider the combined overall impact of the collective depreciation changes for rate-setting purposes under the regulatory principle of fairness, rather than concentrating on any individual changes. According to Manitoba Hydro, the overall impact of the changes is to reduce Depreciation Expense and the associated revenue requirement.

Equal Life Group vs. Average Service Life

To date, Manitoba Hydro has used the ASL methodology of calculating Depreciation Expense. Gannett Fleming testified on behalf of Manitoba Hydro to recommend a switch to the ELG procedure. While the ASL methodology groups assets by type of asset and then depreciates the assets in the group according to their average service lives, ELG groups assets according to their lifespan, not the type of asset. According to Gannett Fleming, the ELG approach more closely tracks the actual depletion of the underlying assets. In Canada, both methods are in use by utilities.

Both the ELG and ASL methodologies are appropriate under International Financial Reporting Standards (IFRS). However, Gannett Fleming indicated that if ASL were to be utilized, the level of componentization into asset groups would have to be more granular than what is currently being presented. Gannett Fleming was of the opinion this additional componentization would significantly reduce the annual difference in Depreciation Expense between ASL and ELG.

Manitoba Hydro estimated that it would cost approximately $2.5 million to further componentize its plant assets to the degree required in order to be IFRS compliant using the ASL procedure. Gannett Fleming further submitted that changing to the ELG procedure would comply with the depreciation requirements of IFRS without the need to further componentize to the level of detail that using an ASL method would require.

Manitoba Hydro also noted that in applying the ASL method to an asset group with a wide dispersion in service lives, it can be expected that assets will retire at ages different than the average life used to depreciate the group resulting in gains and losses upon retirement. IFRS requires that these gains and losses be recognized immediately to net income. Manitoba Hydro submitted that such gains and losses are expected to be much smaller under ELG since this method calculates depreciation with consideration of the different service lives of the assets in a component group.

Manitoba Hydro acknowledged that the existing regulatory practice, whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group and then factored into future depreciation rate changes for the group, may be continued for rate-setting purposes if ordered by the Board pursuant to rate-regulated accounting.

Manitoba Hydro also indicated that if the ASL methodology was retained for rate-setting purposes, IFRS would require Manitoba Hydro to establish a regulatory deferral account and to maintain two separate sets of asset sub-ledgers to capture the differences between depreciation determined for financial reporting and depreciation determined for rate-setting purposes.

Manitoba Hydro initially indicated to the Board that it wanted to switch to ELG in its 2012/13 & 2013/14 GRA. In Order 43/13 the Board stated:

> *The Board also is concerned that not enough information has been provided to date to assess the true impact on ratepayers of a switch to Equal Life Group. As such, the Board will require Manitoba Hydro to file additional information, including a determination of depreciation rates and schedules based on the Average Service Life methodology, to provide a meaningful comparison between the two approaches. [Order 43/13 pg 18]*
>
> *The Board will require Manitoba Hydro to provide a comparison, for the next General Rate Application, of the impact on the Integrated Financial Forecast of an Average Service Life methodology (without net salvage) and an Equal Life Group methodology (without net salvage), where each of the accounting methodologies are applied to planned major capital additions in the Integrated Financial Forecast. Given the forecast to increase net plant by over $21 billion over a 20 year period, it will be important to understand the*

implications on ratepayers of using each approach at the next General Rate Application.

The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to support Manitoba Hydro's view that an Average Service Life methodology compliant with International Financial Reporting Standards requires increased componentization. As part of this information, the Board expects to see evidence as to what level of componentization would be required, and how such level of componentization would increase Manitoba Hydro's costs, if at all. [Order 43/13 pg 18- 19]

...

IT IS THEREFORE ORDERED THAT:

...

8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.

9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

Instead of preparing a depreciation study based on IFRS-compliant ASL, Manitoba Hydro submitted an extrapolation study prepared by Gannett Fleming, based on a sample of plant accounts representing approximately 20% of Manitoba Hydro's total asset base. The analysis was not based on a random statistical sample but based on plant accounts chosen collaboratively with Manitoba Hydro based on select criteria. A random statistically-based sample was not considered because of the time and effort required to evaluate the level of componentization of the selected accounts on this basis.

Based on the results of the study, Gannett Fleming determined a difference in depreciation expense of $700,000 on the plant accounts tested. Extrapolating the results of the analysis indicated that an ASL-based IFRS-compliant depreciation methodology would result in a depreciation expense $3.6 million lower than one based on the ELG procedure.

In cross-examination, it was demonstrated that the extrapolation study was sensitive to changes in assumptions. For example, one of the asset components analyzed was Manitoba Hydro's head office building, which represented less than three percent of Manitoba Hydro's total asset base. Exclusion of this account from the extrapolation analysis increased the difference between ASL and ELG to $4.4 million. Similarly, while the extrapolation study analysis included the Bipole III Transmission Reliability Project, it focused on synchronous condensers, which represent approximately 15% of the cost of the project, but not the metal transmission towers and conductors, which represent approximately 36%. In cross-examination, Gannett Fleming indicated that using the towers and conductors would increase the difference between ASL and ELG.

Both the Consumer Coalition (Coalition) and the Manitoba Industrial Power Users Group (MIPUG) recommended that the Board not approve Manitoba Hydro's proposal to change to the ELG procedure for rate-setting purposes, but retain the ASL methodology without including any net salvage in depreciation rates.

MIPUG submitted that ASL is appropriate for rate setting and is used by the vast majority of regulated North American utilities, particularly Canadian Crown utilities and hydro-based operations.

MIPUG submitted that the use of ASL benefits the intergenerational perspective and that a Crown-owned, hydro-electric utility, such as Manitoba Hydro, should take a consistent and properly matched long term approach to collection of depreciation which matches the use and usefulness of the assets. This is done by using ASL, which charges the same depreciation rate in each year of the asset's life.

MIPUG further submitted that ELG is not a more precise method of depreciation as the claims of ELG precision are linked to a theoretical construct of ELG that is not used in practice, where the theoretical purity of the method is significantly diluted.

Both the Coalition and MIPUG expressed concern related to the extrapolation analysis. An expert witness on behalf of the Coalition and MIPUG testified that the extrapolation study was not reliable and counterintuitive as ELG with a growing asset base will always lead to a higher depreciation expense. MIPUG submitted that the Board should not attribute any evidentiary weight to the extrapolation study.

Both MIPUG and the Coalition argued that the extrapolation study does not comply with the Directive given in Order 43/13 for an IFRS-compliant ASL study. The Coalition recommended the Board find that Manitoba Hydro has not complied with Board Directive 8 from Order 43/13, in which Manitoba Hydro was to file updated depreciation rates and schedules based on IFRS-compliant ASL methodology. The Coalition also recommended that the Board find that its response to Board Directive 9 is inadequate.

The Coalition recommended that the Board not accept ELG for rate-setting purposes on the grounds that Manitoba Hydro failed to comply with Board Directives 8 and 9. The Coalition further recommended that the Board direct Manitoba Hydro to provide a timeline by which it intends to comply with Directives 8 and 9 and, until then, set Manitoba Hydro's revenue requirement based on the traditional ASL methodology.

Removal of Net Salvage

Gannett Fleming advised that IFRS would no longer permit the inclusion of net salvage in the depreciation rate calculations for financial reporting purposes. Depreciation rates currently include a provision for net salvage, representing the cost of disposal of property, plant, and equipment when it is taken out of service. Under IFRS, the future cost to retire and salvage assets will become a cost of the replacement asset.

Manitoba Hydro plans on removing net salvage from depreciation rates when it implements IFRS in conjunction with its proposed change to the ELG methodology.

Manitoba Hydro indicated that it was a policy decision to not request the Board to allow Manitoba Hydro to establish a regulatory deferral account. Manitoba Hydro suggested that this choice was made to reduce the impact of switching to the ELG methodology of depreciation. Manitoba Hydro indicated the impact of removing net salvage from depreciation rates is to lower Depreciation Expense by approximately $60 million in 2015/16.

The Coalition supported MIPUG's recommendation that the Board approve Manitoba Hydro's request for the elimination of ongoing accumulation of net salvage charged through depreciation. MIPUG believes net salvage should be removed from annual calculations as a sound regulatory principle, as the assets are expected to be replaced upon retirement with a new generation of assets that benefits from the pre-existence of the original assets.

Book Accumulated Depreciation Surplus

The change in estimated service lives resulted in a book accumulated depreciation surplus of over $474 million. Book accumulated depreciation surplus is 'over-depreciation' that has resulted from an excess of collected Depreciation Expense on Manitoba Hydro's books. Removing net salvage from the current ASL methodology-based depreciation rates increases the accumulated depreciation surplus to over $1 billion. If depreciation is calculated based on the ELG methodology and no net salvage, the book accumulated depreciation surplus is reduced to approximately $603 million. Manitoba Hydro proposes an annual true-up to refund the balance over the remaining life of each asset account. This approach is consistent with the approach followed in prior depreciation studies.

Board Findings

The Board accepts the calculated book accumulated depreciation surplus based on the 2014 Gannett Fleming study.

The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates as of April 1, 2015, concurrent with Manitoba Hydro's implementation of IFRS. The Board notes that while the inclusion of net salvage creates a cash flow due to eventual asset removal obligations, any such cash flow is not sheltered in any reserve accounts and forms part of the general revenue requirement of Manitoba Hydro instead. The Board heard evidence that energy-generating assets are rarely decommissioned and removed entirely, and are most frequently replaced. In such instances, IFRS requires removal costs for the existing asset to form part of the overall capital cost of the new asset recovered from future ratepayers. In the Board's view, there are no compelling reasons to set up a deferral account to allow for the continued collection of net salvage.

However, the Board, at this time, is not prepared to determine Manitoba Hydro's revenue requirement for rate-setting purposes based on a switch from the ASL methodology to the ELG procedure.

Under either ASL or ELG, Manitoba Hydro is eventually made whole, since by the time an asset is decommissioned, the entire capital cost has been recovered by Manitoba Hydro from ratepayers. However, there is no doubt that over the next twenty years (the timeframe for Manitoba Hydro's integrated financial forecast), a switch to ELG would increase Depreciation Expense in every single year. Furthermore, Manitoba Hydro was unable to advise the Board at which point ratepayers should expect a "crossover point" at which the increased Depreciation Expense recovered in the early years reduces Depreciation Expense in the later years. As such, the Board must assume that during the entirety of the foreseeable 20 year planning horizon, a switch to ELG would increase the amount of Depreciation Expense consumers are expected to fund through their rates.

For purposes of rate-setting, the Board orders Manitoba Hydro to continue to determine Depreciation Expense based on its existing ASL methodology at this time.

This is not to say that the Board is rejecting outright an eventual adoption of ELG. However, to the extent that the choice is between IFRS-compliant ASL and IFRS-compliant ELG, the Board does not currently have sufficient information upon which to make a decision. As shown in the table above, a change in methodology leads to significant long term consumer rate consequences and is a decision which the Board cannot make on an incomplete record.

While the Board considers the extrapolation study filed by Manitoba Hydro to be illustrative, and the Board accepts that additional componentization would reduce the difference between ASL and ELG, the Board does not consider the extrapolation study reliable enough to base a rate-making decision on it. As such, the Board will order Manitoba Hydro to retain the existing ASL methodology for rate-setting purposes until Directives 8 and 9 from Order 43/13 have been complied with and the Board has been provided with an IFRS-compliant depreciation study based on ASL.

Accepting Gannett Fleming's testimony that additional componentization tends to reduce the difference between ASL and ELG, the Board requests that the IFRS-compliant ASL depreciation study, if and when filed by Manitoba Hydro, be based on the minimum level of additional componentization required by IFRS, but avoid optional additional componentization. The study should also demonstrate whether and when there would be a cross-over point at which time Depreciation Expense as calculated using ELG becomes lower than that calculated using ASL. If Manitoba Hydro is able to file such a study in time for the next GRA, as well as comply with Directive 9 from Order 43/13, the Board intends to make a final disposition with respect to the appropriate long term depreciation methodology for rate-setting purposes at the hearing of that Application.

Attachment 113.1

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 114.1

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