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September 25, 2018

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)
Project No. 1598967
Annual Review for 2019 Rates (the Application)
Response to the Industrial Customers Group (ICG) Information Request (IR) No. 1

On August 10, 2018, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-142-18 setting out the Regulatory Timetable for review of the Application, FBC respectfully submits the attached response to ICG IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-2, p. 8, lines 16-1

FBC also "bundled" some projects together to reduce logistical costs during the competitive bid process when outsourcing work.

1.1 Please identify projects that have been "bundled" together to reduce logistical costs in 2017 and in 2018?

Response:

Please refer to the response to CEC IR 1.6.3.

1.2 Please identify such projects by reference to Appendix B2?

Response:

Please refer to the response to CEC IR 1.6.3.

2. Reference: Exhibit B-2, Section 3.5.7, Losses, page 28

> **3.5.7 Losses**
>
> System losses consist of:
>
> - Losses in the transmission and distribution system;
> - Company use;
> - Losses due to wheeling through the BC Hydro system; and
> - Unaccounted-for energy (meter inaccuracies and theft).

2.1 Please proved an estimate of losses for each of the identified categories, and expressed as both percentages and energy quantities. Please identify the methodology used to quantify the losses in each category, and show the linkage back to the 2012 loss study.

Response:

The following table provides a breakdown of system losses in GWh and as a percentage of gross load, through the end of June 2018. Losses are forecast on an aggregate basis, and therefore the breakdown beyond June 2018 is not included in the table below. Note that the table represents actual system losses, as FBC does not have a breakdown of normalized losses. For the method and linkage to the loss study, please refer to the response to BCUC IR 1.12.1.1.

(GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	YTD June 2018
Gross Load	3,399	3,478	3,324	3,452	3,414	3,488	3,450	3,384	3,387	3,596	1,785
Station Service Plants 1-5	6	5	6	6	6	6	6	6	5	6	3
Company Use	6	7	6	7	6	6	7	7	7	7	4
BC Hydro Losses (ARWA)	30	51	41	49	50	55	51	46	46	58	40
FortisBC T&D Losses (including meter inaccuracies and theft)	271	258	227	245	208	210	207	209	208	218	98
% of Gross Load											
Station Service Plants 1-5	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Company Use	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
BC Hydro Losses (ARWA)	0.9%	1.5%	1.2%	1.4%	1.5%	1.6%	1.5%	1.3%	1.4%	1.6%	2.2%
FortisBC T&D Losses (including meter inaccuracies and theft)	8.0%	7.4%	6.8%	7.1%	6.1%	6.0%	6.0%	6.2%	6.1%	6.1%	5.5%
Total	9.2%	9.2%	8.4%	8.9%	7.9%	7.9%	7.9%	7.9%	7.9%	8.0%	8.1%

2.2 The 2012 loss study submitted as part of last year's process contained several errors. Please resubmit the corrected 2012 loss study.

Response:

The corrected 2012 loss study is provided in Attachment 2.2 as requested.

The 2012 January and February billing numbers in cells N4 to O7 did not match the January and February values in cells B13 to C16 in the loss study submitted in the 2018 Annual Review. This has been corrected in the attached file. There was no material impact to the losses.

FBC is currently in the process of updating the loss study using AMI information and intends to use the new study for its 2020 revenue requirements.

3. Reference: Exhibit B-2, Section 4.5, 2019 Power Purchase Expense Forecast, Table 4-3, page 26

3.1 Please provide Table 4-3 expressed as energy quantities from each source for both years, and provide the energy unit costs for each energy quantity expressed as cost dollars megawatt-hour. Include also FBC's owned electricity supply.

Response:

Please refer to the response to BCOAPO IR 1.12.2 for a break down of energy quantities from each source.

The following table provides the energy unit costs for each line item in Table 4-3 expressed as $/MWh. FBC Generation costs are not applicable as they are not included in Power Purchase Expense. Waneta Expansion contract rates are confidential pursuant to Commission Order E-15-12. Loss Recovery refers to the physical delivery of losses from transmission customers and is not associated with a $/MWh rate. The Independent Power Producers and Self Generators costs have been aggregated in the table for confidentiality reasons.

Line No.	Description	Projected 2018	Forecast 2019
1	FBC Generation	N/A	N/A
2	Brilliant	$ 43.18	$ 45.98
3	BC Hydro PPA	$ 70.41	$ 68.72
4	Waneta Expansion	N/A	N/A
5	Market and Contracted Purchases	$ 28.50	$ 31.09
6	Independent Power Producers and Self Generators	$ 83.06[1]	$ 49.83
7	Loss Recovery	N/A	N/A

[1] Please note that the Projected 2018 Independent Power Producers and Self Generators rate is artificially high due to the estimate that was used for June 2018 for accrual purposes. After being trued-up, actual 2018 IPP and Self Generator purchases YTD through June 2018 have an average cost of $55.50/MWh.

4. Reference: Exhibit B-2, Section 5.3, Transmission Access Revenue, page 41

4.1 Please provide the amount of transmission access revenue recovered in 2016 (actual), 2017 (projected and actual) and 2018 (forecast), broken out by each of the applicable tariffs under which the amounts are recovered. Please also include the energy recovered under Rate Schedule 109.

Response:

The historical and other amounts requested are provided below. FBC has also included the 2019 Forecast even though that amount was not requested.

($000s)	2016 Actual	2017 Projected	2017 Actual	2018 Approved	2018 Projected	2019 Forecast
Rate 110	895	807	803	816	816	836
Rate 103	188	182	190	173	173	193
Rate 104	195	190	197	181	181	201
Total Transmission Access Revenue	1,278	1,179	1,190	1,170	1,170	1,230
Rate 109 (GWh)	18	7	19	-	7	-

FBC does not forecast any loss recoveries, as is it is expected to offset the increased load as a result of providing that service.

5. Reference: Exhibit B-2, Section 6.3.3, AMI Project, page 45

5.1 Please provide the net impact of the AMI project on the annual revenue requirement in each of 2018 and 2019, showing separately the impact of the capital project and the forecast savings. Please include all AMI costs such as the AMI Sustainment Capital.

Response:

FBC is able to quantify the incremental revenue requirements components related to the AMI project related to the project capital expenditures, but is unable to quantify with confidence a number of other components, which must be evaluated in comparison to the hypothetical scenario in which FBC had not undertaken the AMI project. While FBC is able to forecast the loss reduction (including theft deterrence), it is unable to quantify the increased sales load due to the impact of voluntary theft cessation. The incremental revenue requirements also requires an estimate of capital spending on meters and meter compliance in the absence of AMI, which cannot be known with any degree of accuracy.

For the purpose of calculating the incremental rate impact, FBC used the actual capital expenditures (including sustainment capital), the forecast of AMI loss reduction as set out in the response to BCUC IR 1.13.1, and the net AMI savings as set out in section 6 of the Application. The avoided revenue requirements in the absence of AMI were calculated using the forecast capital expenditures in the “status quo” case from the CPCN application.

On this basis, FBC estimates the incremental net impact of the AMI project to be approximately (0.5) percent in 2018 and (0.8) percent in 2019.

6. Reference: Exhibit B-2, Section 6.3.4.4, 2018 MRS Compliance Audit, page 49

6.1 Was FBC found to be in possible violation of any Mandatory Reliability Standards (MRS) during the 2018 audit, and if so, which standards. Please include any violations which were self-reported or the subject of Open Enforcement Actions.

Response:

FBC has not been advised of any possible violation of any Mandatory Reliability Standards (MRS) during the audit and there were no Open Enforcement Actions in scope of the 2018 audit. During the three-year audit period, FBC had three self reports, none of which were confirmed violations and none were in-scope of the 2018 audit.

6.2 Has FBC paid any penalties und the MRS violation penalty matrix since 2016?

Response:

No.

7. Reference: Exhibit B-2, Section 6.3.5, Annual Inspection Costs for Upper Bonnington Old Units, pp. 49-50

7.1 Will annual inspection and maintenance costs for the refurbished Upper Bonnington Old Units be lower post refurbishment, and if not, why not?

Response:

The annual inspection and maintenance costs for the refurbished Upper Bonnington Old Units will not be lower post refurbishment. As explained in section 6.3.5, the O&M reduction related to the annual unit inspections is a one-time reduction to O&M Expense in the year that a unit is refurbished. A refurbished unit will once again undergo annual inspections following its refurbishment as the activities involved with the annual inspection and regular maintenance are required to maintain the operation of the unit at a safe and reliable level. Therefore, the level of Base O&M expenditures will not be impacted on an ongoing basis.

8. Reference: Exhibit B-2, p. 62

"FBC is a public issuer of long-term debt. In December 2017, FBC issued long-term debt of $75 million at a rate of 3.62% for a term of 32 years. The net proceeds were used to repay existing indebtedness."

8.1 Please describe the competitive process, if any, for this issue?

Response:

This issuance was completed via a private placement. A private placement was preferred given the issuance amount of $75 million was sub-optimal for a more broadly distributed issuance. The pricing of the private placement was based on secondary trading of FBC debt and discussions with market participants on expected demand. This process of establishing a reference price through market information is consistent with broadly distributed issuances, in which reference pricing is set and the levels of interest shift the pricing up or down marginally by +/- 3 basis points (+/- 0.03%). The competitive process involved approaching a limited number of investors to determine their interest in the private placement offering, at pricing which was consistent with a broadly distributed issuance. A number of the potential investors declined to participate in the issuance at the selected pricing levels; however, there was still sufficient interest to ensure that the issuance was completed at the desired amount, and at competitive pricing levels.

8.2 Please provide the calculation of the net proceedings accounting for all issue/transaction costs?

Response:

FBC incurred debt issue costs of approximately $500 thousand relating to this issuance, resulting in net proceeds of approximately $74.5 million. The debt issue costs included agent commissions, credit rating agency fees, and professional services fees. The BCUC approved the transaction in Order G-101-17. FBC has filed all required documentation with the BCUC subsequent to the issuance on a confidential basis.

8.3 Please identify the interest rate and the maturity date of the existing indebtedness that was repaid?

Response:

The proceeds from the issuance were used for general corporate purposes including financing of FBC's capital program and working capital requirements and the repayment of amounts drawn on FBC's short term credit facility, which carried an average interest rate of 2.36% for 2017.

8.4 Please file a copy of the Commission order that approved this long-term debt issue?

Response:

Please refer to Order G-101-17, available on the BCUC website at the following link:

https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/304743/index.do

8.5 Please identify the issuer and the security provided to the issuer?

Response:

The issuer was FortisBC Inc. (FBC), and the securities issued were medium term note debentures (MTNs) which rank equally with all other outstanding unsecured MTNs.

9. Reference: Exhibit B-2, p. 65

"FBC's capital structure and ROE have been forecast for 2019 at the same percentages as approved for 2018."

9.1 Please provide a comparison of actual vs deemed capital structure for year endings 2016 and 2017, and to the end of June, 2018?

Response:

FBC's actual regulated capital structure is equal to the approved capital structure of 60 percent debt and 40 percent equity for all of the time periods requested.

10. Reference: Exhibit B-2, p. 67

"Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year."

10.1 Please provide details of all property assessments appeals, if any, during the term of the PBR Plan?

Response:

The table below details property assessment appeals from 2014 to 2018. The list does not include pre-roll changes negotiated with BC Assessment, negating the necessity for an appeal. Over the period 2014 to 2018 tax savings directly from assessment appeals totaled $0.058 million.

Property Tax Appeals 2014 to 2018

Year	AA	Jur	Folio	Folio Description	Reason for Appeal	Change in Taxes
2014	17	222	01167.000	Huth Substation	Protective Appeal: Waiting for decision on 2013 Appeal. MV of land with significant archeologial findings. Board found for Assessor	
2014	17	232	00008.100	Trail Esplanade	Value	(10,140)
2014	17	547	00601.000	TL - Within Midway	Removed all TL from Midway - Converted to DL	(21,729)
2014	17	547	00601.050	DL - Within Midway	Added Previous TL inventory to DL	9,793
2014	17	556	00443.010	Osoyoos Substation	Land Value	(510)
2014	17	562	01113.905	RW	Remove Duplicate folio	(37)
2014	17	712	04931-000	RW	Confirm Land Area - Withdrawn	
2014	17	712	11503-005	RW	Confirm Land Area - Withdrawn	
2014	17	713	02796-283	RW	Confirm Land Area - Withdrawn	
2014	17	713	03537.005	RW	Assessed Area too High (SB 0.0741 ac not 13.33)	
2014	17	713	03537.010	RW	Correct Legal	
2014	17	713	03538.005	RW	Duplicate of 03537.010 / Area Incorrect	(225)
2014	17	713	04001.007	RW	Area too High / LFB 4401780 belongs to Telus	(773)
2014	17	713	06735-410	RW	Delete Fully Exempted Folio - Fortis has no interest in land	
2014	17	713	07196.630	RW	Land Values	(45)
2014	17	713	08015.500	RW	Reduced Land Value - Correct RW Area	(301)
2014	17	714	02507.015	RW	FEI Right of Way	(2)
2014	17	714	02507.020	RW	FEI Right of Way	(2)
2015	17	222	01167.000	Huth Substation	Protective Appeal: Waiting for decision on 2013/2014 Appeal.	
2015	17	714	01960.020	RW	Verify RW Area - Withdrawn	
2015	17	714	06580.020	RW	Verify RW Area - Withdrawn	
2015	17	714	11518.070	RW	Verify RW Area - Withdrawn	
2015	17	714	11518.070	RW	Verify RW Area - Withdrawn	
2015	19	723	06860.018	RW	Area too High	(125)
2015	19	723	15249.501	RW	Area too High	(502)
2016	21	232	05000.720	Stoney Creek Sub	Correct Reassessment	(7,314)
2016	21	413	00713.575	Creston Sub	Correct Reassessment	(878)
2016	21	547	00314.050	Midway Sub	Correct Reassessment	(2,113)
2016	21	707	05627.110	RW	Correct RW Area	(528)
2016	21	711	17015.100	Glenmerry Sub	Correct Reassessment	(2,723)
2017	21	707	05695-100	RW	Correct RW Area	(564)
2017	21	709	01575-000	RW	Correct Classification	(4,646)
2017	21	709	01575-000	RW	Correct Classification	(7,572)
2017	21	711	05695-100	Fruitvale Sub	Land Value Reassessment	(1,252)
2018	21	219	05000.000	South Slocan Dam	Value Increase & Classification- Office No longer used	(1,152)
2018	21	219	05000.500	South Slocan Office	Value Increase & Classification- Office No longer used	(2,099)
2018	21	707	1698.18	South Slocan Dam	Classification	(2,774)

11. Reference: Exhibit B-2, p. 104

"The savings are forecast at $0.350 million in 2018 and 2019, which exceeds the materiality threshold of $0.301 million."

11.1 Please provide sources references to the calculation of and approval of the materiality threshold of $0.301 million?

Response:

The Commission directed at page 95 of the PBR Decision that "materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate". FBC provided the following calculation in its Compliance filing to the PBR Decision:

Table 8: Exogenous (Z) Factor Materiality Calculation

($000 unless otherwise stated)

2013 Base O&M	$	60,159
Materiality Threshold		0.5%
Exogenous Factor Threshold	$	301

The 2013 Base O&M pursuant to the PBR Decision was also provided in the Compliance filing:

Table 2: Revisions to 2013 Base O&M

	$000		Directive
Base O&M, Table C4-2		59,848	
Formulaic O&M:			
First and third party liability expense	140		88
Non-specific adjustment	(200)		91
Executive STIP limited to 70% of target	(193)		page 213
Reclass of software upgrades from capital	564		105
		311	
Base O&M, G-139-14		**60,159**	

12. Reference: Exhibit B-2, Section 12.3.1.2, Cloud Computing, pp. 108-110

12.1 Please identify the forecast 2019 and 2020 costs for the cloud computing initiative.

Response:

Please refer to the response to BCUC IR 1.31.5.

12.2 Were there any 2018 costs for cloud computing, and if so, how were these costs treated?

Response:

Please refer to the response to BCUC IR 1.31.1.

12.3 Please identify which IS functions and expenses are currently included in O&M.

Response:

IS costs incurred to develop or obtain internal-use software and cloud computing hosting arrangements that are not capitalized under Subtopic 350-40 are recognized in O&M and include training, support, maintenance and licensing costs.

12.4 Please identify those IS functions which are being considered for transfer to a cloud computing solution.

Response:

The transfer of traditional on-premise IS software and hardware to cloud computing solutions is based on the type of solution, availability and effectiveness of cloud solutions for each particular IS solution that is evaluated. Each IS project takes into consideration the possibility of a cloud solution for all or part of the project. The decision to use a cloud solution is based on overall benefits and is measured against all viable alternatives, including on- premise or internal

1 solutions. As described in Section 12.3.1.2 of the Application, the form in which the solution is
2 offered, either through traditional on-premise software or through cloud computing, is not known
3 until discussions occur with the external vendor.

4

13. Reference: Exhibit B-2, Section 12.4.1.2, Rate Design and Rates for Electric Vehicle (EV) Direct Current Fast Charging Service Application, page 114

"FBC is seeking approval of a deferral account attracting a STI rate of return to capture the external costs of this application, estimated at $0.060 million ($0.44 million after tax). FBC will propose the disposition of this account in a future application."

13.1 Please confirm the correct amounts.

Response:

Please refer to the responses to BCUC IRs 1.32.2 and 1.32.2.1.

14. Reference: Exhibit B-2, Section 12.4.1.3, BC Hydro Waneta 2017 Transaction, page 114

"The Waneta 2017 Transaction involved issues of importance to FBC's future expenses and customer rates. The Company incurred external legal costs of $0.124 million ($0.091 million after tax) for its participation in this proceeding."

14.1 Please explain how the Waneta 2017 Transaction had the potential to affect customer rates.

Response:

Please refer to the response to BCUC IR 1.33.1.

15. Reference: Exhibit B-2, Section 13.2.3, Reliability, SAIDI, pp. 130 – 131

"As recorded on page 7 of the November 21, 2014 minutes for the SQI Workshop, FBC stated that "with AMI, the company may need to assess the impact on the SAIDI measure as the company would be notified of outages earlier than previously"."

15.1 Please provide the annual SAIDI performance for the years 2015 to 2018 (YTD), both with and without qualifying major events.

Response:

Listed below are the annual SAIDI results, both as measured and after removing qualifying major events (the normalized SAIDI). The 2018 August YTD results are based on only eight months of data and as a result are not directly comparable to the previous annual results

	SAIDI	Normalized SAIDI
2018 August YTD	3.23	2.50
2017	5.41	4.05
2016	2.51	2.10
2015	4.53	2.13

15.2 When did the implementation of the OMS system occur? Does this imply that the actual SAIDI performance was underreported in prior years?

Response:

The implementation of the OMS occurred in January of 2017.

SAIDI performance was not under reported in prior years as the benchmark and the actuals prior to implementation of the OMS were both calculated using the same methods.

15.3 Please quantify FBC's estimated impact of the OMS system for the 2017 and 2018 (YTD) annual SAIDI performance.

Response:

Please refer to the response to BCSEA IR 1.2.4.

16. Reference: Exhibit B-2, Section 13.2.3, Reliability, SAIDI, pp. 130 – 131

16.1 Please provide the annual actual operating hours, idle hours, and forced outrage hours for each of FBC's generating units for 2017 and 2018.

Response:

The annual actual operating hours, idle hours, and forced outage hours for each of FBC's generating units for the year 2017 and for June 2018 year-to-date are presented in Tables 1 and 2 below. Please note that FBC calculates the yearly Operating and Idle hours in the April to May period of the following year and as a result the June 2018 year-to-date hours are not available at this time.

Table 1: 2017

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	7489.80	1156.53	10.08
Lower Bonnington - 02	4948.02	3710.88	0.00
Lower Bonnington - 03	8510.73	131.80	4.30
Upper Bonnington - 01	2719.78	5691.27	236.15
Upper Bonnington - 02	3174.33	5403.42	71.13
Upper Bonnington - 03	2446.42	1119.62	1.17
Upper Bonnington - 04	2717.20	5629.85	36.38
Upper Bonnington - 05	7322.98	587.02	18.42
Upper Bonnington - 06	4526.58	3615.67	20.63
South Slocan - 01	5363.33	3028.65	0.00
South Slocan - 02	7176.72	1380.30	0.00
South Slocan - 03	8409.93	115.02	0.80
Corra Linn - 01	6331.68	2374.08	2.48
Corra Linn - 02	8618.62	1.30	32.70
Corra Linn - 03	5757.02	2902.43	100.43

Table 2: June 2018 YTD

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	-	-	0.00
Lower Bonnington - 02	-	-	0.70
Lower Bonnington - 03	-	-	0.00
Upper Bonnington - 01	-	-	0.00
Upper Bonnington - 02	-	-	1.77
Upper Bonnington - 03	-	-	15.92

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Upper Bonnington - 04	-	-	0.00
Upper Bonnington - 05	-	-	81.88
Upper Bonnington - 06	-	-	0.00
South Slocan - 01	-	-	3.32
South Slocan - 02	-	-	0.00
South Slocan - 03	-	-	2.33
Corra Linn - 01	-	-	0.55
Corra Linn - 02	-	-	0.18
Corra Linn - 03	-	-	0.13

17. Reference: Exhibit B-2, Appendix A2, Load Forecast Tables, Table p. 5

17.1 Please describe the relative increases in summer and winter peaks? On a percentage basis is the summer peak increasing faster than the winter peak, and if so, please describe any steps taken by FortisBC in response, and any analysis undertaken of the different rates of growth of summer vs. winter peaks, if any?

Response:

The annual growth rates for the normalized summer and winter peaks from 2008 to 2017 are below. The average normalized summer peak growth from 2008 to 2017 is 1.7 percent while the winter peak growth over the same period is 0.3 percent. For convenience, the winter peak and summer peak rows are reprinted from Appendix A2, Table 5.1.

Annual Normalized Winter and Summer Peak Growth from 2008 to 2017

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Average
Winter Peak (MW)	707	704	726	702	723	698	693	685	755	717	
Winter Peak Growth Rate (%)	0.5%	-0.4%	3.1%	-3.3%	2.9%	-3.4%	-0.8%	-1.1%	10.2%	-5.0%	0.3%
Summer Peak (MW)	502	496	566	537	589	600	620	611	593	605	
Summer Peak Growth Rate (%)	-3.4%	-1.3%	14.1%	-5.2%	9.8%	1.9%	3.2%	-1.4%	-2.9%	2.0%	1.7%

FBC recently completed a Demand Response (DR) potential study as part of the BC Conservation Potential Review additional scope services. Although the focus of the study was on mitigating winter peak periods that continue to set FBC's annual peak system load, some measures (e.g. direct load control of hot water tanks) are applicable to offsetting summer peaks. FEI filed the DR potential study as Appendix A-1 of its 2019-2022 DSM Expenditure Schedule application.

Currently FBC is undertaking a more detailed DR assessment for the Kelowna region that will quantify both summer and winter peak offsets. The target is larger commercial customers to enable the subsequent pilot phase that is anticipated to test both summer and winter DR. FBC considered assessing a primarily residential area that experiences summer peaking, but elected to proceed with the commercial customer assessment to get the additional benefit of testing winter peak clipping.

17.2 Please breakout MWh for the system between the same summer and winter months used in the System Peak table and for the same period as used in the System Peak table?

Response:

The normalized gross loads during the peak months from 2008 to 2017 are shown below. The 2018 and 2019 values are not included since the Winter and Summer peaks are derived based on load growth and escalated Winter and Summer peaks not monthly peaks. In addition, the 2018 Gross Load Winter Peak is an estimate. Winter peak is either the December or November peak of the current year or the January or February peak of the next year. The Winter Peak for 2017 was in January of 2018 and therefore the load can only be estimated at this time since the 2018 actual load will not be available until February of 2019.

Normalized Gross Load during Peak Month 2008 to 2017 (GWh)

Peak Monthly Energy (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Winter	358	361	366	354	363	380	366	363	361	331
Summer	277	277	274	274	272	291	285	286	281	289

Consistent with the Application and past practice the above table is presented using units of GWh instead of MWh.

17.3 Please calculate add the load factor for the summer and winter months for the period used in the System Load Factor table found on p. 12?

Response:

The requested table is below.

Normalized Summer and Winter Peak Load Factor

	Summer Peak				Winter Peak			
Year	Peak Month	Normalized Monthly Gross Load (MWh)	Normalized Peak (MW)	Load Factor	Peak Month	Normalized Monthly Gross Load (MWh)	Normalized Peak (MW)	Load Factor
2012	Jul	272,143	589	0.62	Dec	362,555	723	0.67
2013	Jul	291,183	600	0.65	Dec	380,406	698	0.73
2014	Jul	284,643	620	0.62	Jan	365,681	693	0.71
2015	Jul	286,189	611	0.63	Jan	363,248	685	0.71
2016	Aug	280,588	593	0.64	Jan	361,265	755	0.64
2017	Aug	288,941	605	0.64	Jan	331,328	717	0.62
2018	N/A	N/A	608	N/A	N/A	N/A	754	N/A
2019	N/A	N/A	616	N/A	N/A	N/A	764	N/A

FBC is unable to provide the forecast for the 2018 and 2019 Monthly Gross Loads associated with the forecast peak since it is unknown which months the winter and summer peaks will occur in.

18. Reference: Exhibit B-2, Appendix A2, Load Forecast Tables, Table p. 6

18.1 Please explain the forecast of customer additions for lighting and irrigation in 2019?

Response:

FBC does not forecast changes in the Lighting and Irrigation customer count. FBC forecasts the Lighting and Irrigation load itself using historical load data and therefore does not use the Lighting or Irrigation customer counts to forecast the respective loads. Lighting and irrigation customer count changes would not have a significant impact on the overall customer count forecast accuracy.

19. Reference: Exhibit B-2, Appendix B2, Unanticipated transmission projects to address safety and reliability issues, p. 4

"Improvements to the Right of Way conditions along the 30L transmission line (63kV line) from South Slocan substation to Coffee Creek substation to mitigate the potential for fires related to vegetation growth and to reduce the number tree-contact related outages."

19.1 Please explain why these improvements are treated as capital rather than part of normal O&M activities?

Response:

Part of the improvements that have been identified are for acquiring additional Rights of Way, which are registered easements granting the right for FBC to use certain areas of land for utility operations to construct and maintain transmission networks, for the right of entry to ensure safety and dependability of the network, and for emergency purposes. Acquiring Rights of Way is considered an asset because it provides economic benefits for more than one year.

Part of the planned acquisition of Rights of Way will include clearing of vegetation to assist with improving the number of tree-contact related outages on 30L. While brushing is generally an operating cost when it relates to the sustainment of minimum clearances on existing Rights of Way, when new Rights of Way are secured the initial clearing of vegetation is capitalized. This is due to the initial clearing being a requirement to establish the Right of Way minimum clearances and part of the cost of bringing the Right of Way to the condition necessary for its intended use.

19.2 Please provide a breakdown of costs and activities that comprise the improvements.

Response:

The projected capital cost for 30L Right of Way improvements in 2018 is $0.200 million. The capital expenditures will be split between the following activities:

- Patrol and helicopter reconnaissance to determine areas outside of the existing Right of Way and typically upslope that are a priority for harvesting based on tree related outages;
- Acquisition of additional land rights outside of the existing Right of Way in these high priority areas;

- Tree harvesting in high priority areas with newly acquired land rights; and
- Improvements to Right of Way access.

A cost breakdown of expenditures is not available at this time as scope definition is ongoing.

20. Reference: Exhibit B-2, Appendix B2, Substation projects to address end of life equipment replacements, p. 4

20.1 Please explain why these replacements were not included as part of sustaining capital?

Response:

The replacements were recorded as sustaining capital actual costs in the years that they were executed.

20.2 Please identify the capital replacement projects and costs (forecast and actual) that were undertaken in 2017 and 2018. Were any planned projects deferred?

Response:

Please refer to the table below for a list of substation projects to address end of life equipment replacements.

Description	$(millions) 2017 Actual	$(millions) 2018 Projected
Lee T4 transformer Load Tap Changer Replacement	1.15	
Upper Bonnington Generating Station 63-kV switch replacement		0.23
Concrete structure remedial work at Upper Bonnington Generating Station		0.10
Grounding mitigation for personnel safety at Corra Linn Generating Station switchyard		0.35
Oil inhibitor treatment for generating unit transformers		0.02

One project, the replacement of the wood beams supporting the buswork at the Upper Bonnington station, was deferred. This $70 thousand project was deferred to coordinate with other projects required at this site in future years.

21. Reference: Exhibit B-2, Appendix C, Upper Bonnington Unit Refurbishment Project, Status Report, p. 4

"The proposals received either did not meet the objectives of the RFP or contained pricing that was considerably higher than budgeted.

As a result, FBC cancelled the RFP and individually bid each component."

21.1 Please confirm that FBC has accepted bids for each component that was within the scope of the RFP? If so, please provide a price comparison of the aggregate of the accepted bids and the RFP bids?

Response:

This response is being filed confidentially pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents established by Order G-1-16. The information is of a commercially sensitive nature, and significant harm or prejudice to FEI's vendors and to FEI's competitive or negotiating position are reasonably expected to result if the confidential information was made public.

21.2 Does FBC now expect to be on budget for the scope of work in the RFP?

Response:

The cost to refurbish and replace the Unit 4 mechanical components is higher than budget due to the equipment condition being worse than anticipated. The variances related to the Unit 4 mechanical work have largely been offset by savings elsewhere.

21.3 Please provide details of discussions, if any, between FBC and BC Hydro about this project since this project was approved? In particular, has BC Hydro confirmed that this work is required pursuant to the CPA? If so, please provide all relevant correspondence?

Response:

FBC has discussed this project with BC Hydro at the CPA Operating Committee meetings and as part of normal outage planning coordination. FBC has met all of its CPA contractual obligations with respect to this project and at no time did BC Hydro state any objections.

Under the CPA, FBC is responsible for maintaining its own units and there is no requirement for BC Hydro to approve such work. As such, there is no correspondence with BC Hydro stating BC Hydro's approval of the project. This project was approved by Commission in Order G-8-17.

21.4 Please identify consequences, if any, to the entitlement under the CPA that would be attributable to a delay in the commissioning date?

Response:

For any delays in the commissioning date, FBC would continue to take an entitlement reduction, as it would for any unit outage pursuant to the CPA. Actual costs will depend on the time of the year, and market and system conditions at the time. For a single UBO old plant unit outage, the average monthly cost of a delay would be about $38 thousand in 2019.

Attachment 2.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)