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August 10, 2018

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

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

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-138-14 (the PBR Plan)

Annual Review for 2019 Rates

In accordance with the PBR Plan and Commission Order G-142-18 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2019 Rates Application materials.

Should further information be required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FBC's Annual Review for 2018 Rates Proceeding

FORTISBC INC.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review for 2019 Rates

Volume 1 - Application

August 10, 2018

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (the Commission) Order G-139-14, which approved a Performance Based Ratemaking Plan (PBR Plan) for FBC for the years 2014 to 2019. In accordance with the PBR Plan, an annual review process is required to set rates for each year of the PBR Plan. With the filing of this Application, FBC seeks to commence the fifth annual review of the PBR Plan and set FBC's rates for 2019.

The PBR Plan approved by the Decision attached to Order G-139-14 (PBR Decision) increases FBC's incentives to seek out savings while maintaining service quality.[1] Pursuant to the earnings sharing approved by the Commission, savings in formula-driven O&M and capital expenditures achieved by the Company are shared equally with customers, as discussed in Section 10 of the Application.

Under the PBR Plan, FBC projects savings in 2018 due to a continuation of its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling of vacancies and a number of initiatives that result in net O&M and capital savings. Overall, FBC proposes to distribute $0.345[2] million in earnings sharing to customers in 2019. FBC achieved these savings while maintaining a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed rates for 2019 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 1.55 percent decrease from 2018 rates; however, FBC is proposing to maintain 2019 rates at existing levels and to capture the revenue surplus in the deferral account approved to capture the 2018 revenue deficiency. This will avoid the volatility associated with a rate decrease in 2019 followed by a potentially larger rate increase in 2020 when certain large capital projects begin to enter rate base.

In the subsections below, FBC sets out the approvals it is seeking, provides an overview of the requirements for the annual review process, and provides an evaluation of the PBR Plan for 2018. This is followed by a summary of FBC's proposed revenue requirement and rate changes for 2019 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

[1] PBR Decision, p. 134.
[2] This amount is pre-tax and includes both the 2018 estimated earnings sharing and adjustments related to 2017 actuals.

1.2 APPROVALS SOUGHT

With this Application, FBC requests Commission approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act*:

1. Maintain 2019 rates at approved 2018 levels;
2. The following non rate base deferral account approvals, as described in Section 12.4 of the Application:
    - Creation of a deferral account for the 2018 DSM Expenditure Schedule application, to be financed at the Company's short term interest (STI) rate, with a one-year amortization period;
    - Creation of a deferral account for the Rate Design and Rates for Electric Vehicle (EV) Direct Current Fast Charging Service Application, to be financed at FBC's STI rate, with disposition to be proposed in a future application;
    - Creation of a deferral account for costs related to FBC's participation in British Columbia Hydro and Power Authority's (BC Hydro) Waneta 2017 Transaction application, to be financed at FBC's STI rate, with a one-year amortization period;
    - The addition of the 2019 revenue surplus of $4.204 million after tax to the existing 2018 Revenue Deficiency Deferral Account, which will be renamed to the 2018 – 2019 Revenue Surplus Deferral Account, and the financing of this account at FBC's weighted average cost of debt (WACD).
    - A four-year amortization period for the existing Multi-Year (2019-2022) Demand Side Management Expenditures deferral account, commencing in 2019.
    - A five-year amortization period for the existing 2017 Cost of Service Analysis and Rate Design Application deferral account, commencing in 2019.
    - Amortization of the existing Castlegar Office Disposition deferral account in 2019.
3. Z-factor treatment for the 2019 Employer Health Tax, 2018 and 2019 MSP premium reductions, and the 2018 incremental O&M and capital expenditures related to the Mandatory Reliability Standards (MRS) Assessment Reports No. 8 and No. 10, as described in Section 12.2 of the Application.
4. Approval to recognize cloud computing implementation costs to be capitalized consistent with traditional on premise hardware and software for 2019, as described in Section 12.3.1.2.

A draft order is included in Appendix E.

FBC notes that the approvals sought above will be impacted by one other regulatory proceeding in progress.

1.2.1 2019 – 2022 Demand Side Management Application

On August 2, 2018, FBC filed its Application for Acceptance of Demand Side Management Expenditures for 2019 – 2022 (DSM Application). Approvals sought within the DSM Application include an increase in expenditures and a change to the amortization period of DSM expenditures, both of which will impact the 2019 forecasts within this Application. When a decision is issued for the DSM Application, FBC will incorporate the DSM Application decision in its compliance filing to this Application.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On pages 179 and 180 of the PBR Decision, the Commission set out its expectations for the Annual Review component of the PBR Plan, with one further directive on page 17 of Order G-120-15 in the Capital Exclusion Criteria compliance filing. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application:

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.	Section 1.4
2	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 2(a) to 2(g) below
2(a)	Customer growth, volumes and revenues;	Section 3
2(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
2(c)	Expenses (determined by the PBR formula plus flow-through items);	Section 6
2(d)	Capital expenditures (as determined by the PBR formula plus flow-through items);	Section 7
2(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;	Sections 7 and 12
2(f)	Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and	Section 10
2(g)	Any proposals for funding of incremental resources in support of customer service and load growth initiatives.	FBC does not have any proposals at this time

Item	Description	Response or Reference
3	Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives.	FBC has not identified any efficiency investments with a payback beyond the end of the PBR period that it is not pursuing
4	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers.	Section 12.2
5	Review of the Companies' performance with respect to SQIs. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service.	Section 13
6	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.	FBC does not have any recommendations for new SQIs or the discontinuation of SQIs at this time
7	Assess and make recommendations to the Commission on the scope for future Annual Reviews.	FBC does not have any recommendations at this time
8	Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the 1-X mechanism.	Dead band is projected to be exceeded for 2018. See section 1.4.3.

1.4 *EVALUATION OF THE PBR PLAN*

FBC has continued its productivity focus in 2018 and initiated additional projects to enhance the customer experience and improve productivity, in addition to the continuing initiatives from prior years. As a result of this focus and these initiatives, FBC was able to continue to realize savings in O&M expenditures above those embedded in the formula. FBC continues to be challenged to meet growth and maintain the system within the capital formula amount. Overall, the savings achieved result in $0.345[3] million of earnings sharing that will be returned to customers in 2019, serving to reduce overall rates for FBC's customers. FBC's performance with respect to SQIs, as reported in Section 13 of the Application, demonstrates that FBC achieved these net savings while maintaining a high level of service quality.

[3] This amount is pre-tax and includes both the 2018 estimated earnings sharing and adjustments related to 2017 actuals.

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

provided to customers. Customers and other users (e.g. potential customers, contractors, businesses, media, government, etc.) usually visit the FortisBC website with a specific objective in mind. They seek answers to "How do I… ?" questions. Redesigning the website to be more customer centric with self-service options will make it easier for customers to quickly interact with the Company and find answers to their questions. Additionally, operational efficiencies will result from the use of a new content management technology platform and workflow functionality with content authoring and publishing becoming more streamlined. Estimated annual savings are forecast to be $0.15 million shared between FEI and FBC. The project is currently underway with completion expected in 2019.

1.4.3 Overview of Capital Expenditures

FBC is projecting that capital expenditures will be above the formula in 2018.

1.4.3.1 Capital Spending Results

FBC's capital spending has been above the formula amount in each year of the PBR term to date, and this trend is expected to continue. Table 1-3 below shows the capital spending from 2014 to 2018.

Table 1-3: Capital Expenditures 2014 to 2018 ($ millions)

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 42.665	$ 42.193	$ 0.472	$ 44.791	$ 42.384	$ 2.408	$ 45.838	$ 42.874	$ 2.964
Pension/OPEB	6.396	6.396	-	4.253	4.253	-	3.674	3.674	-
Total	$ 49.061	$ 48.589	$ 0.472	$ 49.043	$ 46.637	$ 2.408	$ 49.512	$ 46.548	$ 2.964
Variance			0.97%			5.16%			6.37%

	2017			2018			Cumulative		
	Actual	Formula	Variance	Forecast	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 59.053	$ 43.254	$ 15.799	$ 55.212	$ 43.818	$ 11.394	$ 247.558	$ 214.523	$ 33.035
Pension/OPEB	3.539	3.539	-	3.630	3.630	-	21.492	21.492	-
Total	$ 62.592	$ 46.793	$ 15.799	$ 58.842	$ 47.448	$ 11.394	$ 269.050	$ 236.015	$ 33.035
Variance			33.76%			24.01%			14.00%

As shown in Table 1-3, Projected 2018 capital expenditures excluding items forecast outside of the PBR formula, are $11.394 million higher than the formula amount. There are a number of contributing factors which are discussed below.

One set of contributing factors consists of reductions to the capital formula envelope. Specifically, in the Commission's PBR Decision, the approved PBR capital formula included the following decreases to the allowed spending as compared to what had been proposed:

1. The growth factor for net customer additions was reduced by one-half,[5] resulting in an impact of $0.3 million in 2018 and $1.0 million cumulative; and

[5] In addition, the lag in timing of when customer growth is reflected in the formula as compared to when customers are actually added causes pressure on the formula in years of higher customer growth.

2. The X factor was increased by 0.53 percent (from 0.5 percent to 1.03 percent), resulting in an impact of $0.2 million in 2018 and $1.2 million cumulative.

In addition to the formula related pressures noted above, FBC has continued to experience other capital cost pressures in 2018 due to work that had been re-prioritized from previous years of the PBR term into 2018 and to manage unforeseen urgent and higher priority activities in 2018.

In response to the capital directives on page 14 of Order G-38-18, capital variances are detailed by year in Appendix B2.

FBC has sought to mitigate the impact of the above factors through a combination of seeking out efficiencies in capital spending and re-prioritizing projects for further evaluation. As reported in the 2017 annual review, FBC initiated 2018 projects earlier in the planning process. Projects and programs were prioritized in such a manner to allow for early engineering and design, procurement of equipment, and comprehensive pre-job planning. The pre-job planning phase enabled FBC to schedule work outside of flooding and fire season avoiding unnecessary costs. FBC also "bundled" some projects together to reduce logistical costs during the competitive bid process when outsourcing work. FBC continues to find efficiencies in the execution of condition assessment programs

FBC has been successful in mitigating some of the cost pressures through efficiencies and work prioritization. However, the cost pressures have exceeded the Company's ability to re-prioritize further work within the formula capital spending. As well, previous work that was delayed is now considered essential or mandatory work and cannot be deferred further. To mitigate this risk exposure, FBC has increased its sustainment activities in 2018. This, combined with growth capital pressures, has resulted in FBC forecasting its capital expenditures to be $11.394 million above the formula for 2018, which is over the one-year capital dead band and the two-year cumulative 15 percent dead band.

1.4.3.2 Treatment of Capital Spending outside of the Dead Band

In the Annual Review for 2018 Rates in Section 1.4.3.2, FBC reviewed the regulatory history for the capital dead band. Based on that regulatory history and as further explored during the review proceeding for that application, the functioning of the approved capital dead band is summarized below.

- The capital dead band places a limit on the extent to which there is earning sharing on variances from (either above or below) the capital formula amount;
- The threshold for the capital dead band is a one year 10% variance or a two-year cumulative 15% variance from the capital formula amount;
- If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and

the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount;

- The result of exceeding the capital dead band is that there is no earnings sharing for amounts outside of the dead band;
- If the capital dead band is exceeded, FBC will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

This treatment was approved by Order G-38-18[6]:

> ***The Panel approves FBC's proposal to remove the capital expenditures in excess of the cumulative dead band from the earnings sharing calculation and add it to FBC's opening 2018 plant additions balance.***

In the same paragraph, the Panel stated the following regarding rebasing of the capital formula:

> …it is the Panel's view that initiating a process to determine any adjustments to base capital is not an efficient solution to the capital expenditures in excess of the dead band given the short time remaining in the current PBR term. The current PBR term is 2014–2019 and the Panel acknowledges that any adjustments to base capital may not be determined until the final year of the PBR or later. Therefore, the Panel does not consider it appropriate to undertake a re-basing process during the current PBR term.

FBC agrees that re-basing of capital expenditures should not be undertaken during the remainder of the current PBR term. While FBC is continuing to experience capital cost pressures, the dead band mechanism remains a reasonable way to deal with capital cost pressures by ensuring no sharing of negative earnings impacts with customers for capital expenditures in excess of 10 percent of the formula amount or 15 percent over two years.

To calculate the 2018 dead band adjustment, FBC notes that its actual 2017 capital exceeded the formula by approximately 8.63 percent, after the 2017 dead band adjustment. FBC is further expecting to exceed the 2018 formula by 24.01 percent as shown in Table 1-3. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 32.64 percent. FBC must exclude from the Earnings Sharing calculation the greater of:

[6] G-38-18, page 14.

- The one-year capital dead band difference between the projected capital spending overage of 24.01 percent and the one year dead band limit of 10 percent, for a net adjustment of 14.01 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 32.64 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 17.64 percent.

Accordingly, FBC added 17.64 percent of its 2018 formula capital, or $8.372 million[7] to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two year dead band of 15 percent. FBC also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($8.372 million), such that the earnings sharing with customers is increased (see section 10 of the Application). In this way, there is no earnings sharing on the amount by which FBC exceeded the dead band.

FBC has also included a true-up to the 2017 dead band adjustment in this Application. In FBC's Annual Review for 2018 Rates FBC had projected a 2017 dead band adjustment of $11.268 million that was added to 2018 opening plant balance for rate making purposes. The actual 2017 dead band adjustment is $11.759[8] million due to additional growth capital pressures beyond what was forecast. Consequently, FBC has increased the 2018 opening balance plant for this Application by the actual 2017 dead band adjustment of $11.759 million. Both the 2017 Actual and the 2018 Projected dead band adjustments are included in rate base in calculating 2019 rates.

1.4.3.3 Conclusion on Capital Spending

While FBC is continuing to experience capital cost pressures, the capital spending is required to add customers and limit increasing risk exposure in the system, and avoid unplanned and urgent capital work that reduces productivity and drives up project costs by reducing FBC's ability to plan and execute the work.

1.4.4 Summary

In summary, FBC's experience in 2014 through 2018 has resulted in the realization of earnings sharing on O&M with no rate increases for two of the six years. The experience during the PBR Plan term has also shown the challenges of the capital formula.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2019*

The proposed rates for 2019 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 1.55

[7] 2018 Actual expenditure of $58.842 million - $8.372 million = $50.470 million. This results in a revised capital spending variance of 6.37% over one year and 15% over two years.

[8] Section 10, Table 10-2, Line 28

percent decrease from 2018 rates; however, FBC is proposing to maintain 2019 rates at existing levels and to capture the revenue surplus in the existing Revenue Deficiency deferral account.

The following chart summarizes the items that contribute to the 2019 revenue surplus including the proposed credit to the Revenue Deficiency account so that rates are maintained at existing levels. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2019 surplus, $5.759 million, is then the sum of all of the previous bars and is shown at the end of the chart in blue, to bring the total revenue deficiency or surplus to zero.

Figure 1-1: 2019 Revenue Surplus ($ millions)

Each of the categories is discussed briefly below.

1.5.1 Load Forecast (Section 3)

In 2019, sales load is forecast to increase by 106 GWh from 2018 Approved primarily due to higher residential usage on a per customer basis and to higher commercial loads. Wholesale and Industrial loads also increased compared to 2018 Approved. Based on 2018 rates, FBC's 2019 revenue forecast at existing rates is $370.534 million.

1.5.2 Power Supply (Section 4)

Power Supply expense is forecast to increase in 2019 by $12.315 million, primarily due to an increased gross load and increased purchases under the Company's power purchase agreement with BC Hydro.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase in 2019 by approximately $0.852 million. The main driver of this increase is Late Payment Charges, which relates to the interest earned from utility customers paying invoices past their due date and which were not included in the 2018 forecast.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the bulk of its O&M costs by formula during the PBR term. For 2019, the formula incorporates an inflation factor (I Factor) of 2.505 percent, a productivity improvement factor (X Factor) of 1.03 percent and a customer growth factor of 0.888 percent for a total increase in formula O&M of 2.376 percent. O&M forecast outside of the formula is $0.693 million lower than Approved 2018. Overall the increase in Gross O&M Expense from 2018 to 2019 is 1.039 percent. The increase in net O&M expense is $0.517 million.

1.5.5 Depreciation and Amortization (Section 7)

Depreciation expense has increased by $1.748 million as a result of additions to rate base. Amortization expense decreased by $5.920 million, primarily due to amortization of the credit balance in the 2018 Flow-through deferral account and the true-up of the 2017 Flow-through deferral account. In total, the 2019 Forecast depreciation and amortization expense is lower than 2018 Approved by $4.172 million.

1.5.6 Financing and Return on Equity (Section 8)

FBC issued long-term debt of $75 million at a rate of 3.62 percent for a term of 32 years and does not plan to issue any long-term debt in 2018 or 2019. FBC is forecasting a short-term debt rate for 2019 of 3.55 percent, a slight increase over the 3.45 percent rate embedded in the 2018 approved. Overall, interest expense is forecast to increase from 2018 approved by $0.884 million.

Increases in rate base increase the equity return by $0.741 million. In calculating 2019 rates, FBC has utilized its 2019 approved capital structure and return on equity of 40 percent and 9.15 percent, respectively.

1.5.7 Taxes (Section 9)

Property taxes are forecast to increase 0.2 percent or $0.029 million from 2018 Approved. Increases are driven by changes in property tax rates and assessed values and changes in revenues to calculate grants in lieu of taxes.

There has been no change in the income tax rate of 27 percent from 2018. Income taxes are forecast to decrease in 2018 by $1.922 million, primarily due to the amortization of the regulatory flow-through accounts refunded to customers, in addition to the generally offsetting impacts of higher before-tax earnings and other tax timing.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC's 2017 and June 2018 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2017, for those SQIs with benchmarks, seven performed at or better than the approved benchmarks with one exceeding the threshold. In 2018 June year-to-date, performance is similar to 2017, with seven of the eight SQIs with benchmarks performing better than the benchmark and one exceeding the threshold. For the three SQIs that are informational only, performance generally remains at a level consistent with prior years. Details of the SQIs are included in Section 13.

2. FORMULA DRIVERS

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2019 O&M and Capital formula amounts according to the PBR formula.

In the PBR Decision and Commission Order G-163-14, the Commission approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting, and a growth factor of 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as $[1 + ((AC_{t-1} – AC_{t-2})/ AC_{t-2}) \times 50\%)]$.

Further guidance on how to calculate the Inflation and Growth factors was provided in Commission Order G-182-14, which states:

1. FortisBC Inc. is approved to use inflation data from the most recent 12-month period (July through June) for the 2014 rate change calculations and future annual reviews.
2. FortisBC Inc. is approved to use Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.

The Inflation Factor and Growth Factor calculations utilize these inputs, but as applied to 2019. FBC has used July 2017 through June 2019 inflation data for the 2019 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2019 inflation factor based on prior year's BC-CPI and BC-AWE is 2.505 percent, and the AC Growth Factor is 0.888 percent.

2.1 *INFLATION FACTOR CALCULATION SUMMARY*

In the PBR Decision, the Commission approved an inflation factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting. Consistent with Commission Order G-182-14 regarding FBC's PBR Compliance Filing, FBC uses inflation data from July through June and CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC. The supporting Statistics Canada CANSIM Tables 326-0020 and 281-0063 are provided as Appendix A1. The latest available month of May 2018 has been used as a placeholder for the month of June 2018 for AWE-BC, as results for June have not been released by Statistics Canada. Once results for that period are available, the placeholder will be replaced with actuals and included in an Evidentiary Update.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing CPI-BC of 2.345 percent and AWE-BC of 2.635 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (2.345 percent x 45 percent) + (2.635 percent x 55 percent) = 2.505 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002=100	*CANSIM 281-0063*	12-Month Average		Year over Year % Change			
	BC CPI Index	BC AWE $	CPI Index	AWE $	CPI %	AWE %	I-Factor %	PBR Year
Jul-16	123.3	916.30						
Aug-16	123.4	922.72						
Sep-16	123.2	919.27						
Oct-16	123.1	918.42						
Nov-16	122.7	927.27						
Dec-16	122.7	931.13						
Jan-17	123.5	930.35						
Feb-17	123.6	930.17						
Mar-17	124.2	934.96						
Apr-17	124.4	936.88						
May-17	125.0	940.14						
Jun-17	125.2	944.40	123.7	929.33				
Jul-17	125.6	937.98						
Aug-17	125.9	941.65						
Sep-17	125.7	952.43						
Oct-17	125.6	952.38						
Nov-17	125.9	952.81						
Dec-17	125.2	957.62						
Jan-18	126.1	956.68						
Feb-18	127.0	958.80						
Mar-18	127.4	963.03						
Apr-18	127.7	952.75						
May-18	128.4	959.86						
Jun-18	128.6	959.86	126.6	953.82	2.345%	2.635%	2.505%	2019

2.2 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the Commission approved for FBC a growth factor of 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as $[1 + ((AC_{t-1} – AC_{t-2})/ AC_{t-2}) \times 50\%)]$.

The calculation for the Average Customer growth factor is provided in Table 2-2 below:

Table 2-2: Average Customer (AC) Growth Factor Calculation

	Customer Count	12 Month Average Customers	AC Factor @50%	PBR Year
Jul-16	132,421			
Aug-16	132,618			
Sep-16	132,682			
Oct-16	133,019			
Nov-16	133,140			
Dec-16	133,550			
Jan-17	133,452			
Feb-17	133,582			
Mar-17	133,543			
Apr-17	133,785			
May-17	133,862			
Jun-17	134,154	133,317		
Jul-17	133,938			
Aug-17	134,059			
Sep-17	134,573			
Oct-17	134,765			
Nov-17	135,444			
Dec-17	135,793			
Jan-18	136,067			
Feb-18	136,235			
Mar-18	136,488			
Apr-18	136,713			
May-18	136,856			
Jun-18	137,283	135,685	0.888%	2019

2.3 *INFLATION AND GROWTH CALCULATION SUMMARY*

Using the I-Factor and Growth Factor as calculated above, and the approved X-Factor of 1.03 percent, a summary of the factors used in the PBR formula for 2019 is provided in Table 2-3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2019
1	Cost Drivers	
2		
3	Customer Growth Factor @ 50%	0.888%
4		
5	Escalators	
6		
7	CPI	2.345%
8	AWE	2.635%
9		
10	Non Labour	45%
11	Labour	55%
12		
13	CPI/AWE Inflation	2.505%
14		
15	Productivity Factor	-1.030%
16		
17	Net Inflation Factor	1.475%

In summary, the formula factor for O&M and capital for 2019 is 102.376 percent, calculated as (1+0.888 percent) x (1+1.475 percent).

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system energy load. The gross system energy load is a combination of residential, commercial, wholesale, industrial, street lighting and irrigation loads, and system losses. The forecast of gross system energy load includes the impacts of forecast energy savings, which includes Demand Side Management (DSM) savings, the Customer Information Portal (CIP)[9], the Advanced Metering Infrastructure (AMI) program and future rate changes. These savings are further explained in Section 3.3 – Demand Side Management and Other Savings.

FBC's load forecast methods, described below, are consistent with those used in prior years and accepted by the Load Forecast Technical Committee in 2011[10]. FBC is forecasting an increase in consumption in 2019 when compared to the 2018 Approved forecast. The total normalized gross load is forecast to be approximately 3,602 GWh which is a 116 GWh increase compared to the 2018 Approved gross load. The increase in 2019 is due to increased loads in the residential, commercial and industrial classes. Based on the 2018 rates for each customer class, FBC's 2019 revenue forecast is $370.534 million.

3.2 *OVERVIEW OF FORECAST METHODS*

FBC's forecast of customers and load relies on the following components:

- Residential and commercial customer count forecasts;
- Residential average use per customer (UPC) forecast;
- Commercial, lighting and irrigation load forecasts; and
- Industrial and wholesale survey-based forecasts.

The load forecast for residential customers is based on forecasts for customer count and UPC, consistent with past practice. Specifically, the UPC is forecast and is then multiplied by the corresponding forecast of the number of customers to derive the load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, while the lighting and irrigation forecasts are based on trend analysis and a 5-year average, respectively. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A3 of this filing.

[9] CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customers to view historic billing and consumption data. The CIP was implemented in June 2017.

[10] The report of the Load Forecast Technical Committee is found in Exhibit B-16, FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan.

In the figures provided below, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For the 2019 Annual Review the latest calendar year for which full actual data exists is 2017.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2019 is the Forecast Year (2019F).
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available[11], and will be different than the original forecast for that year in the previous year's revenue requirements. For example, for this Application the Seed Year is 2018 (2018S) and the Seed Year forecast is based on the latest actual years, including 2017.

Also included in the figures in this section are the prior year's seed year (2017S) and forecast year (2018F) as presented in the Annual Review for 2018 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures that follow in this section.

3.3 *DEMAND SIDE MANAGEMENT AND OTHER SAVINGS*

DSM savings and other savings are forecast on an incremental basis (i.e. incremental to the savings embedded in historical loads to 2017).

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. Residential energy sales are further reduced by the CIP, but increased by recovered sales from the AMI-based revenue protection programs. In prior years the Residential Conservation Rate (RCR) also reduced the residential load but the customer changes in consumption are assumed to have been fully realized in 2017 and therefore no additional savings are projected for 2018S and 2019F. Rate-driven reductions in load due to price elasticity are also taken into account and deducted from the before-saving loads for all classes. All forecast values in this section are shown after being reduced by DSM and other savings unless explicitly stated otherwise.

The forecast DSM and other savings for 2019F are summarized in Table 3-1 below. Historic DSM and other savings can be found in Appendix A2.

[11] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast 2019 DSM and Other Savings (GWh)

Line No.	Description	DSM	AMI	CIP	Rate-Driven	Total
1	Residential	(10)	8	(4)	(0)	(7)
2	Commercial	(21)			(0)	(21)
3	Wholesale	(2)			(0)	(2)
4	Industrial	(3)				(3)
5	Lighting	(3)				(3)
6	Irrigation	(0)				(0)
7	Net	(39)	8	(4)	(0)	(36)
8	Losses	(3)	(5)			(9)
9	Gross Load	(42)	2	(4)	(0)	(44)

3.4 *RESIDENTIAL AND COMMERCIAL CUSTOMER FORECAST*

Table 3-2 shows the year-end customer count for FBC.

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

The forecast commercial customer count is determined by a regression of the year-end customer accounts on the provincial GDP forecast from the CBOC, which is included in Appendix A1.

Consistent with past practice, FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. One new industrial customer has been added to FBC's industrial class during 2018.

No additions are forecast for other rate classes.

Table 3-2: Year-End Direct Customer Count

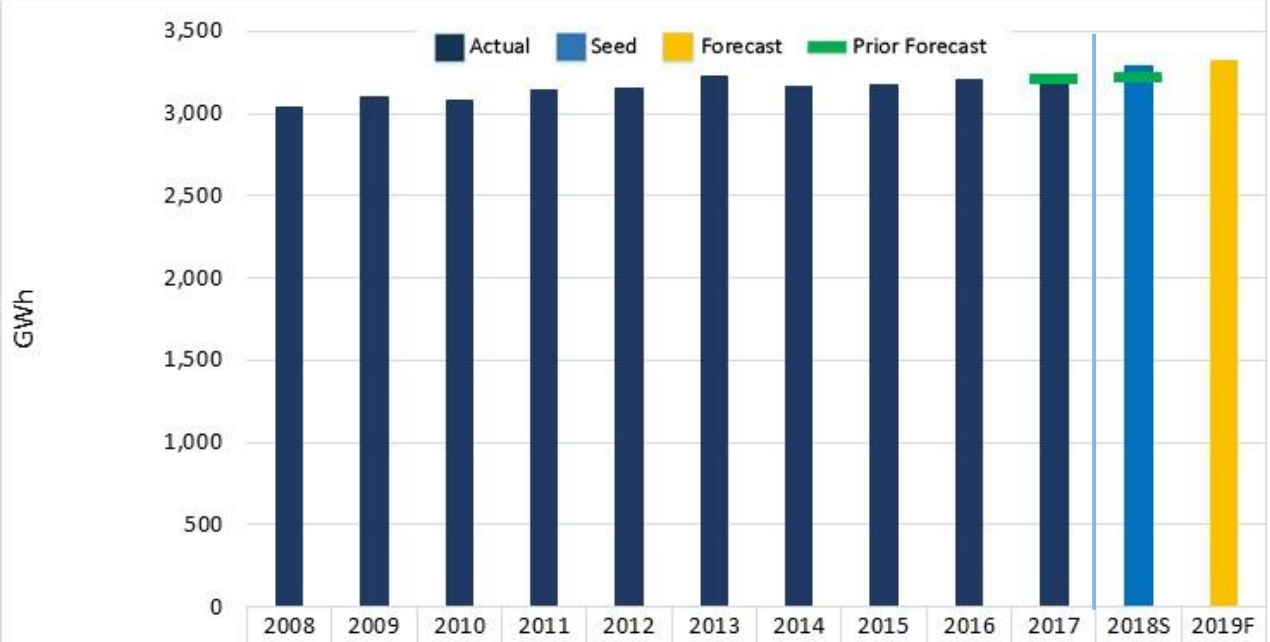
Line No.	Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
1	Residential	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,772	117,748	118,934	120,405
2	Commercial	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,398	16,110	16,405
3	Wholesale	7	7	7	7	7	6	6	6	6	6	6	6
4	Industrial	36	33	35	36	39	47	49	50	50	50	51	51
5	Lighting	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,511	1,511	1,511
6	Irrigation	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,080	1,080	1,080
7	**Total**	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,793	137,692	139,459

3.5 *LOAD FORECAST*

A discussion of the forecast for each customer class is provided in Sections 3.5.1 through 3.5.6, and losses and peak demand forecasts are discussed in Sections 3.5.7 and 3.5.8.

As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,319 GWh in 2019F, up 31 GWh from 2018S.

Figure 3-1: Total Net Load (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	3,042	3,100	3,085	3,140	3,151	3,222	3,163	3,174	3,206	3,230	3,288	3,319
Prior Year Forecast										3,209	3,213	

Table 3-3 below shows the weather-normalized after-savings gross load by customer class as well as the normalized peak. For 2019F the residential customer class is forecast to account for 37 percent of the normalized after-savings gross load.

Table 3-3: Normalized After-Savings Gross Load and Peak

Line No.	Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
	Energy (GWh)												
1	Residential	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,337	1,349
2	Commercial	661	675	660	657	681	788	863	853	905	915	934	935
3	Wholesale	908	908	895	910	899	675	567	580	574	574	580	594
4	Industrial	218	216	234	271	291	352	381	380	373	363	380	385
5	Lighting	13	13	14	13	13	13	16	16	16	16	15	13
6	Irrigation	46	49	40	40	38	40	40	46	42	42	42	42
7	Net Load	3,042	3,100	3,085	3,140	3,151	3,222	3,163	3,174	3,206	3,230	3,288	3,319
8	Losses	309	315	284	307	271	278	270	272	274	282	283	283
9	Gross Load	3,351	3,416	3,369	3,447	3,422	3,500	3,433	3,446	3,480	3,512	3,570	3,602
10													
11	System Peak (MW)												
12	Winter Peak	707	704	726	702	723	698	693	685	755	717	754	764
13	Summer Peak	502	496	566	537	589	600	620	611	593	605	608	616

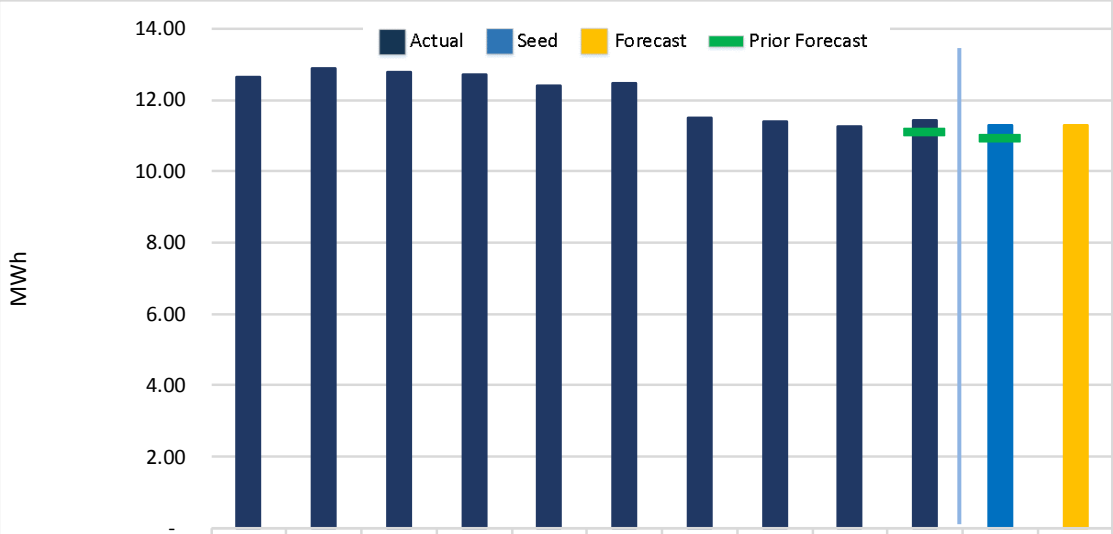
3.5.1 Residential

3.5.1.1 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. FBC reviews the forecast methods on an annual basis and found that there was no statistically significant trend in the most recent UPC data and therefore applied a three-year average.

The before-savings UPC is forecast by applying a three-year average to the most recent three years' normalized historical UPCs (2015, 2016, and 2017). The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM and other savings, which are incremental savings (that is, savings incremental to those embedded in the historical data to 2017), are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count. As shown in Figure 3-2 below, the residential after-savings UPC is forecast to decrease by 0.3 MWh during 2019F.

Figure 3-2: Normalized After-Savings Residential UPC (MWh)



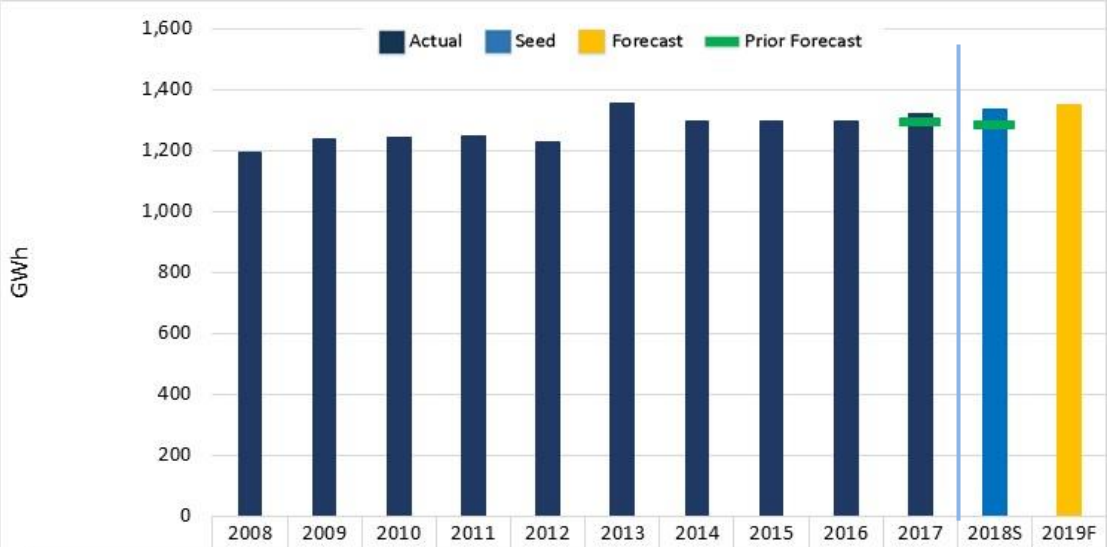
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.42	11.30	11.27
Prior Year Forecast										11.10	10.92	

3.5.1.2 Residential Load

Consistent with past practice, the total before-savings energy forecast for the residential class is the product of the average annual residential customer count multiplied by the forecast residential UPC. The after-savings load is produced by taking the before savings load and then

subtracting DSM and other savings. As shown in Figure 3-3 below, residential after-savings energy is forecast to increase by 12 GWh in 2019F compared to the 2018S.

Figure 3-3: Normalized After-Savings Residential Load (GWh)

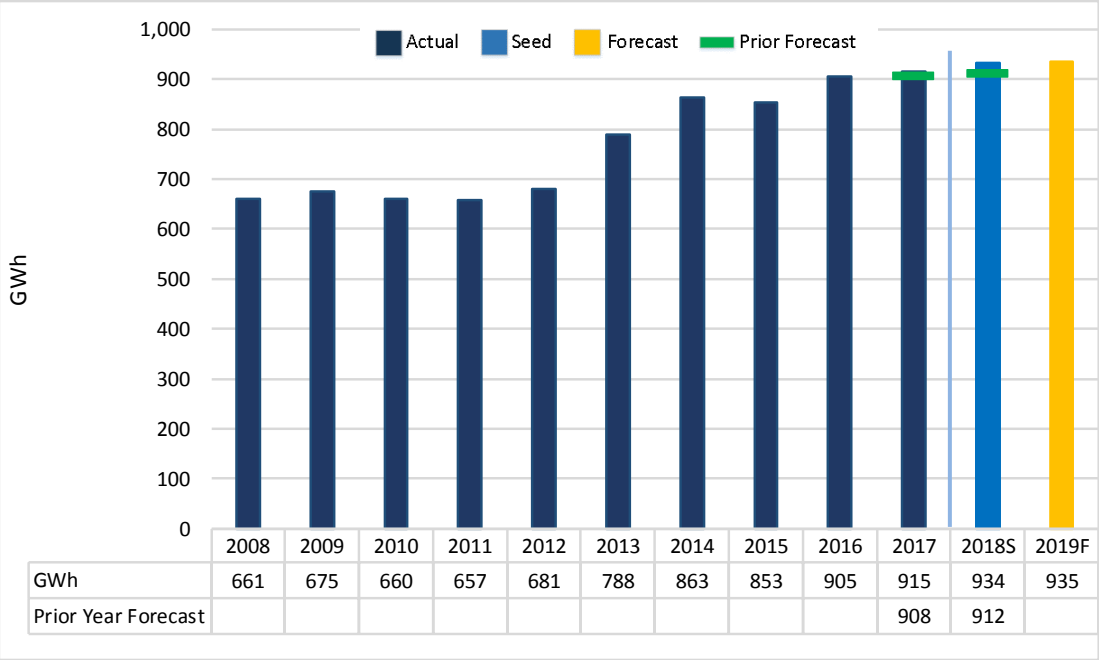


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,337	1,349
Prior Year Forecast										1,290	1,280	

3.5.2 Commercial

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. As shown in Figure 3-4 below, Commercial after-savings energy is forecast to increase by 19 GWh in 2018S and 1 GWh in 2019F. The higher growth in 2018S as compared to 2019F is due to a larger GDP projection from the CBOC for 2018S (3.1% in 2018S and 1.8% in 2019F) and increased DSM savings in 2019F (8 GWh in 2018S and 21 GWh in 2019F), due in part to projected lighting upgrades.

Figure 3-4: After-Savings Commercial Load (GWh)[12]



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	661	675	660	657	681	788	863	853	905	915	934	935
Prior Year Forecast										908	912	

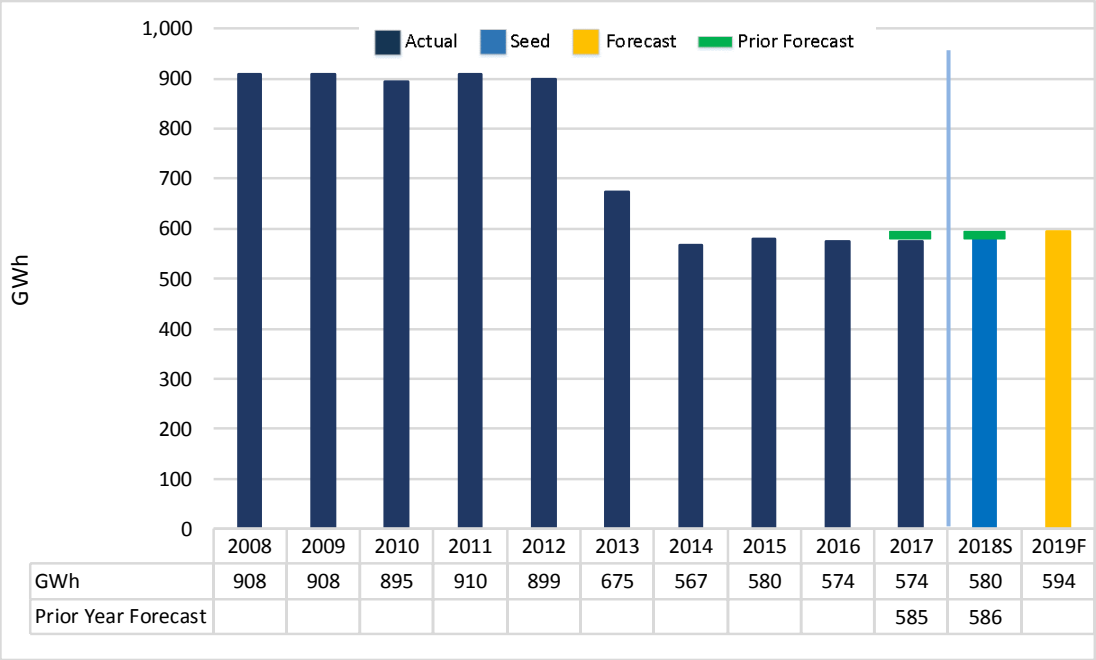
3.5.3 Wholesale

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems and to BC Hydro for service to certain of its customers. These wholesale customers' load composition is a combination of residential, commercial, industrial and street lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers. FBC believes that the individual wholesale customers are best able to forecast their future load growth. All of the wholesale customers responded with their load forecast projections. As shown in Figure 3-5 below, after-savings wholesale energy is forecast to increase by 6 GWh in 2018S and 14 GWh in 2019F. The increase in 2019F is partially due to commercial developments within certain wholesale customer's territories.

[12] Commercial load is normalized from 2014: see Appendix A3, section 1.1.

Figure 3-5: Normalized After-Savings Wholesale Load (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	908	908	895	910	899	675	567	580	574	574	580	594
Prior Year Forecast										585	586	

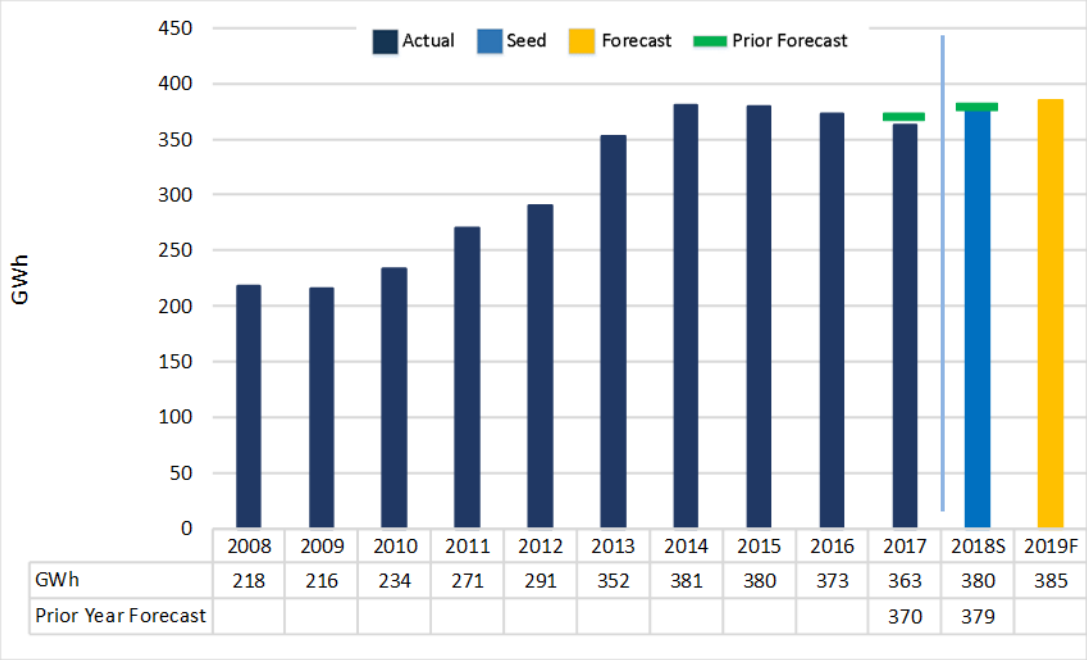
3.5.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future energy usage will be. This year FBC received a response from 86 percent (44 of 51) of the surveys sent out. The responding customers represent approximately 88 percent of the total industrial load.

As shown in Figure 3-6 below, after-savings industrial energy is forecast to increase by 17 GWh in 2018S. This increase is partially due to a new industrial customer added in January 2018 that increases the load by approximately 11 GWh per year. Industrial energy is forecast to increase by 5 GWh in 2019F compared to 2018S.

Figure 3-6: After-Savings Industrial Energy (GWh)

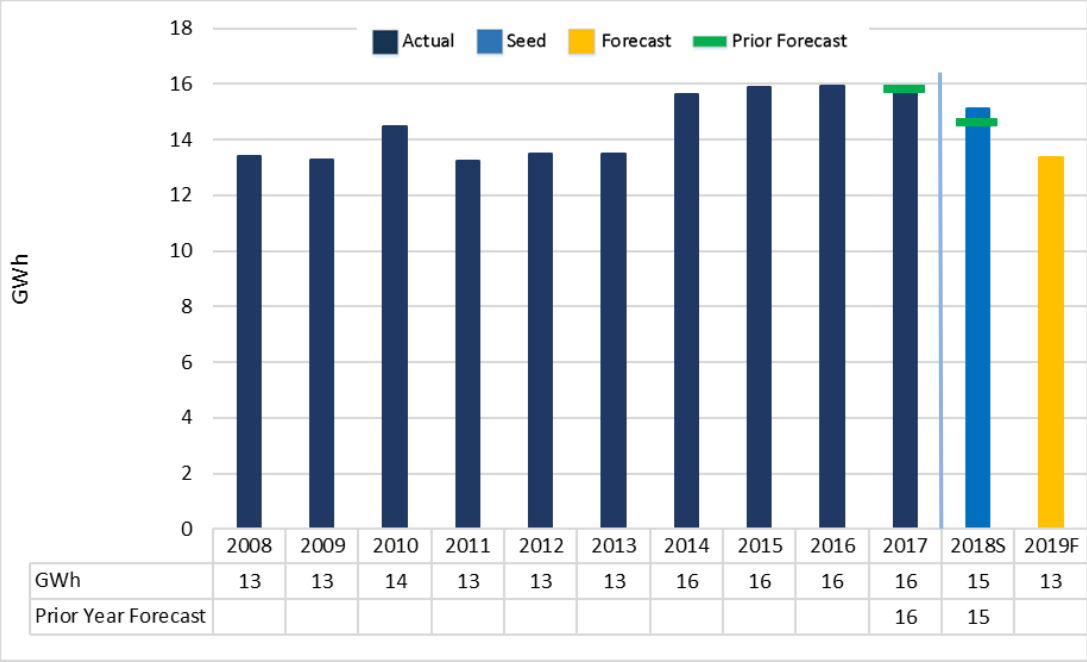


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	218	216	234	271	291	352	381	380	373	363	380	385
Prior Year Forecast										370	379	

3.5.5 Lighting

Consistent with past practice, FBC used a trend of the most recent five-year period to forecast load for this class. As shown in Figure 3-7 below, after-savings lighting energy is forecast to decrease by 2 GWh in 2019F compared to 2018S. Part of this reduction is due to the implementation of LED street lights which can reduce the amount of electricity needed for a single street light by 50 percent to 65 percent.

Figure 3-7: After-Savings Lighting Load (GWh)

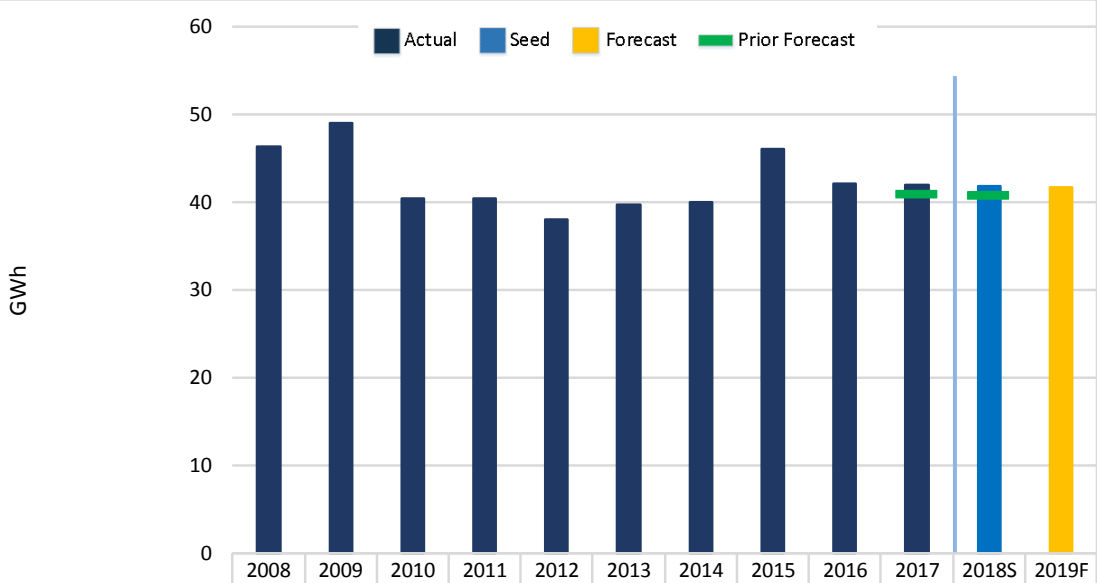


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	13	13	14	13	13	13	16	16	16	16	15	13
Prior Year Forecast										16	15	

3.5.6 Irrigation

Consistent with past practice, FBC used an average of the most recent five-year period to forecast load for this class. As shown in Figure 3-8 below, after-savings irrigation energy is forecast to remain constant in 2019F.

Figure 3-8: After-Savings Irrigation Load (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
After-Savings Growth	46	49	40	40	38	40	40	46	42	42	42	42
Prior Year Forecast										41	41	

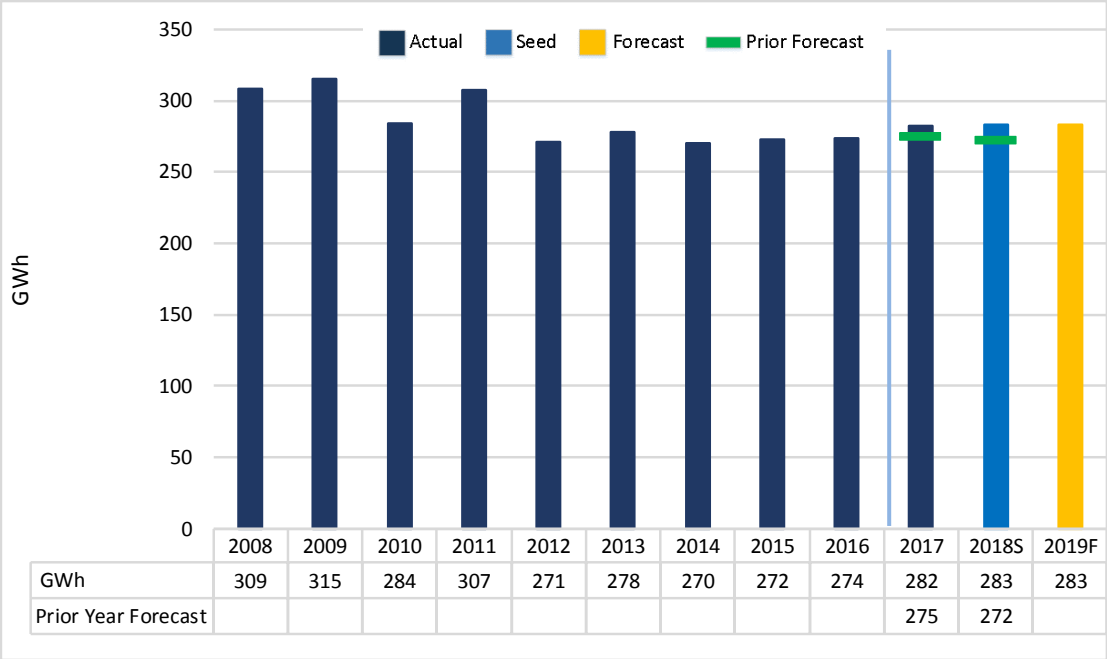
3.5.7 Losses

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).

Consistent with past practice FBC assumed a loss rate of 8 percent of gross load, before the AMI impact, which is explained below. The 8 percent loss rate was based on a loss study that was conducted in 2012, which is in line with the loss rate that FBC is recording on an annual basis. FBC is currently working on an updated loss study that will utilize AMI data. The updated study is projected to be complete for the 2020 forecast. As shown in Figure 3-9 below, after-savings energy losses are forecast to remain constant in 2019F.

Figure 3-9: Normalized After-Savings Losses Load (GWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
GWh	309	315	284	307	271	278	270	272	274	282	283	283
Prior Year Forecast										275	272	

3.5.7.1 Advanced Metering Infrastructure (AMI) Impact on Losses

FBC's implementation of AMI (approved by Order C-7-13) is expected to positively impact losses (unaccounted-for energy) by deterring theft of power, mainly from indoor marijuana grow sites. In Order G-107-15 in FBC's Annual Review for 2015 Rates, FBC was directed to include in its next and subsequent Annual Review materials the impact of AMI on losses through theft deterrence, including:

(i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and

(ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.[13]

The following information on theft reduction, the costs and activities incurred reducing electricity theft and regulatory treatment is provided in response to this directive.

The projected GWh theft reduction for the test year and subsequent years is unchanged from the estimated GWh theft reduction assumed in the AMI decision. The AMI decision included the impact of the Commission's determination to limit the number of assumed marijuana grow cycles to three per year, resulting in assumed annual energy losses of 113,000 kWh annually per theft site.

Current forecast loss reductions remain unchanged from those provided as part of the AMI CPCN application, as modified by the determinations provided in Order C-7-13. Table 3-4 below provides details of the normalized losses for 2013 – 2017, as well as the forecast losses (both with and without the AMI impact) for 2018 – 2019. The 2017 AMI impact to losses related to theft detection and deterrence is 3.9 GWh, which is consistent with the original forecast. The 2017 loss figures are embedded in the 2018 – 2019 loss figures noted in Table 3-4.

Table 3-4: System Losses Before and After AMI, 2013 – 2019

		Before AMI				After AMI	
Line No.	Year	Normalized Actuals and Before-Savings Gross Load	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	Incremental AMI Impact (GWh)	% of Gross Load	Losses (GWh)
1	2013 Actual	3500.0	7.95%	278.1			
2	2014 Actual	3433.6	7.86%	269.9			
3	2015 Actual	3446.2	7.91%	272.5			
4	2016 Actual	3480.3	7.87%	274.1			
5	2017 Actual	3511.8	8.02%	281.8			
6	2018 Seed	3570.0	8.03%	286.6	(4.2)	7.89%	281.8
7	2019 Forecast	3601.6	8.06%	290.5	(7.6)	7.84%	282.5

Note: The AMI impacts are incremental to the losses before AMI in each year, and are incorporated into the forecast for the following year (the 2019 forecast includes a 2018 forecast reduction of 4.2 GWh plus a 2019 forecast reduction of 3.4 GWh).

[13] Order G-107-15, page 15.

FBC has implemented its energy balancing program, and is also leveraging the tamper detection functionality of the AMI system for theft identification.

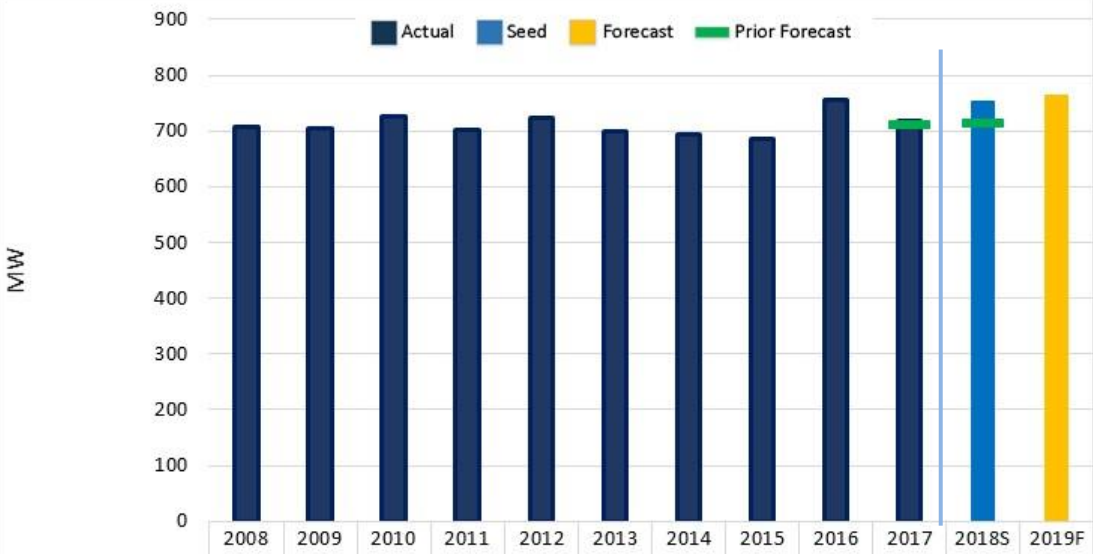
The following discussion of O&M costs related to the AMI-enabled revenue protection program, and their regulatory treatment is provided in this section in response to the directive cited above. The O&M expenditures incurred in reducing electricity theft that are incremental to those included in Base O&M relate primarily to the addition of a Revenue Protection Analyst for managing the development and operation of the AMI-enabled energy balancing program, as well as the necessary field resources for the periodic deployment and relocation of the feeder metering devices as required. The incremental costs to manage the AMI-enabled energy balancing program include 2018 O&M expenditures of $0.270 million.

The AMI costs associated with FBC's Revenue Protection Program that are incremental to the Revenue Protection program costs included in formula O&M are forecast and tracked outside of the PBR formula. Any variances from forecast are recovered from or returned to customers in the following year by way of the Flow-through deferral account as discussed in section 6.3.

3.5.8 Peak Demand

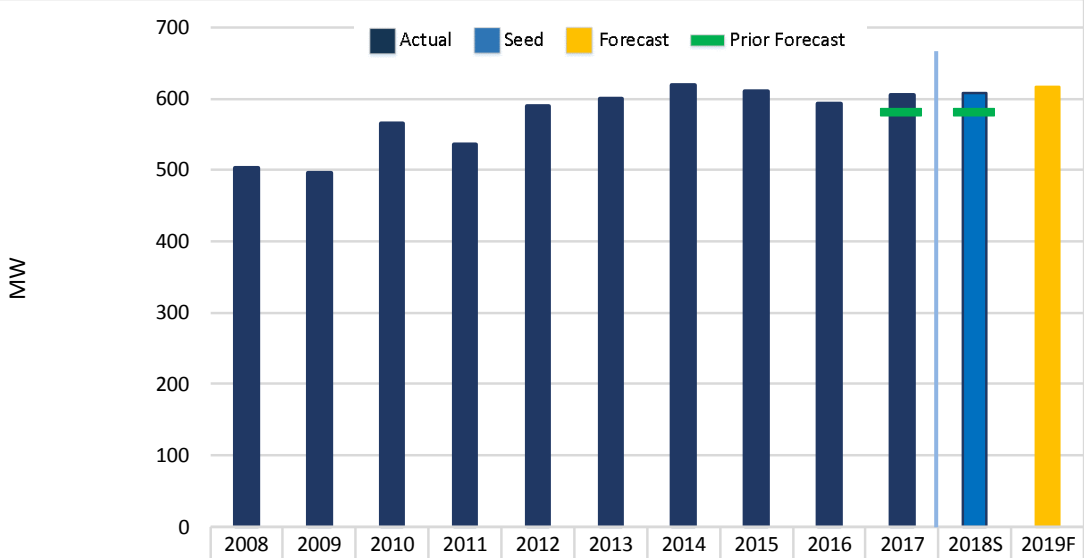
The peak demand forecast is produced using the ten-year average of historical peaks. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Normalized after-savings winter and summer peaks for 2008-2017 are shown below along with the 2018S and 2019F forecast.

Figure 3-10: After-Savings Winter Peaks (MW)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
MW	707	704	726	702	723	698	693	685	755	717	754	764
Prior Year Forecast										710	712	

Figure 3-11: After-Savings Summer Peaks (MW)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
MW	502	496	566	537	589	600	620	611	593	605	608	616
Prior Year Forecast										580	581	

3.6 *REVENUE FORECAST*

The forecast of revenues has been developed by applying approved 2018 rates to the forecast billing determinants for each customer class. Table 3-5 below summarizes the approved, projected and forecast revenue for 2018 and 2019.

Table 3-5: Forecast Sales Revenue at 2018 Approved Rates ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Residential	$ 178.976	$ 188.775	$ 187.887
2	Commercial	90.669	92.607	94.508
3	Wholesale	48.565	40.330	49.519
4	Industrial	31.712	38.248	32.414
5	Lighting	2.903	3.140	2.661
6	Irrigation	3.515	3.083	3.544
7	Total	$ 356.340	$ 366.184	$ 370.534

When comparing the 2018 Approved forecast to 2018 Projected there is an increase in revenue of $9.844 million, the majority of which is due to higher than forecast customer growth, higher residential UPC, and the addition of a new industrial customer.

2019 Forecast revenue is $14.194 million higher than 2018 Approved for the same reasons. In addition, wholesale load and revenue increases due to the commercial development identified in Section 3.5.2 above.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 SUMMARY

FBC's forecast of load is based upon methods that are consistent with those used in prior years and conform to the recommendations of the 2011 Load Forecast Technical Committee. The normalized after-savings gross energy forecast is 3,602 GWh. Based on net load of 3,319 GWh at the approved 2018 rates, FBC's 2019 revenue forecast is $370.534 million.

When comparing the 2019 forecast to the 2018 Approved there is an increase in gross load of 116 GWh. The increase in 2019F is primarily due to increased loads in the residential and commercial classes. Wholesale and Industrial loads and revenues also increased compared to 2018.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2018 Projected and 2019 Forecast power purchase expense (PPE), wheeling expense and water fees.

As shown in Table 4-1 below, the 2019 Forecast power supply cost of $160.765 million represents an increase of 8.3 percent or $12.315 million compared to the 2018 Approved cost of $148.450 million. The increase in the 2019 Forecast Power Supply cost is mainly due to increased gross load and increased purchases under the Company's power purchase agreement with BC Hydro. The 2019 Forecast wheeling expense is forecast to increase due to increased wheeling rates. 2019 Forecast water fees have also increased compared with 2018 Approved as a result of increased rates. Any variances to forecast in these items are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Power Purchase Expense	$ 133.071	$ 130.247	$ 145.065
2	Wheeling Expense	5.171	5.281	5.235
3	Water Fees	10.208	10.287	10.465
4	Total Power Supply Cost	$ 148.450	$ 145.814	$ 160.765
5				
6	Gross Load (GWh)	3,485	3,573	3,602

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year to year timing differences in the entitlement energy storage under the CPA;

2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00) and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro Rate Schedule 3808 (Order G-60-14);

4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
5. A number of small Independent Power Producer (IPP) contracts; and
6. A number of market purchase arrangements.

4.3 PORTFOLIO OPTIMIZATION

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply substantially all of its 2019 forecast annual energy and capacity requirements. The nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by the Commission in Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by the Commission in Order E-10-15.

4.4 FBC 2018/19 ANNUAL ELECTRIC CONTRACTING PLAN

On March 23, 2018, FBC filed its 2018/19 Annual Electric Contracting Plan (AECP) with the Commission. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2018 and ending September 30, 2019, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to displace PPA purchases with lower cost resources or to manage annual loads that are below forecast. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated

energy but depending on system conditions, could be more or less.[14] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2018 and for 2019 are based on the plan detailed in the 2018/19 AECP, which was accepted by the Commission on April 26, 2018, by way of Letter L-8-18.[15]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2018/19 contract year equal to 683 GWh, less any firm market contracts that FBC could enter into, as described in section 5 of the 2018/19 AECP.

Before June 30 of 2018, FBC entered into energy supply contracts (ESCs) with Powerex under the terms of the CEPSA, which provide FBC with 71 GWh of incremental market energy during the winter of 2018/19, and 48 GWh during the winter of 2019/2020, all at a lower cost than if supplied under the PPA. The ESCs were submitted for BCUC approval under two separate applications, one on May 28, 2018 (accepted by order E-20-18) and the second on July 30, 2018. FBC has prepared its forecast under the assumption that they will be accepted as filed. The ESCs and associated savings are included in the 2019 Forecast PPE. As a result of these contracts, and changes to the forecast gross load, the Company submitted a PPA nomination for the 2018/19 contract year of 725 GWh on June 25, 2018, as confirmed in a letter to the BCUC on July 30, 2018.

4.5 *REVIEW OF 2018 POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2018 gross load (after taking into account DSM and other customer savings) is expected to be 87 GWh above the 2018 Approved value, while PPE is projected to be below the 2018 Approved value by $2.824 million. The reduction in 2018 projected power purchase expense is primarily due to additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost.

[14] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh

[15] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-8-18.

Table 4-2: 2018 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Difference
1	Brilliant	$ 39.632	$ 39.620	$ (0.012)
2	BC Hydro PPA	44.906	38.623	(6.283)
3	Waneta Expansion	37.437	37.797	0.360
4	Market and Contracted Purchases	10.951	14.923	3.972
5	Independent Power Producers	0.080	0.081	0.002
6	Self-Generators	0.066	0.028	(0.038)
7	CPA Balancing Pool	-	(0.826)	(0.826)
8	Special and Accounting Adjustments	-	0.002	0.002
9	Total	$ 133.071	$ 130.247	$ (2.824)
10				
11	Gross Load (GWh)	3,485	3,573	87

4.6 *2019 POWER PURCHASE EXPENSE FORECAST*

As shown in Table 4-3 below, the 2019 Forecast PPE is approximately $14.818 million greater than the 2018 Projected. The forecast increase from $130.247 million in 2018 to $145.065 million in 2019 is a result of an increase in gross load and as well as a reduction in market and contracted purchases and correspondingly, a greater reliance on relatively higher cost energy supplied by BC Hydro. Also contributing to the increase are reduced surplus sales along with escalations to BC Hydro, Waneta Expansion, and Brilliant contract rates.

Table 4-3 shows a comparison of the 2018 Projected PPE and the 2019 Forecast PPE. Reasons for significant variances from the 2018 Projected PPE are discussed below.

Table 4-3: 2018 and 2019 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2018	Forecast 2019	Difference
1	Brilliant	$ 39.620	$ 41.865	$ 2.245
2	BC Hydro PPA	38.623	52.174	13.551
3	Waneta Expansion	37.797	40.221	2.424
4	Market and Contracted Purchases	14.923	10.637	(4.286)
5	Independent Power Producers	0.081	0.076	(0.005)
6	Self-Generators	0.028	0.093	0.065
7	CPA Balancing Pool	(0.826)	-	0.826
8	Special and Accounting Adjustments	0.002	-	(0.002)
9	Total	$ 130.247	$ 145.065	$ 14.818
10				
11	Gross Load (GWh)	3,573	3,602	29

The $2.245 million increase from 2018 Projected to 2019 Forecast in the Brilliant expense is due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

BC Hydro PPA expense increased by $13.551 million in the 2019 Forecast compared to the 2018 Projected. A forecast BC Hydro rate increase of 2.6 percent on April 1, 2019[16] accounts for $1.480 million, whereas higher purchased volume (211 GWh) increases the 2019 Forecast expense by $13.071 million[17]. For the 2019 Forecast, FBC has included a $2.000 million reduction to the forecast BC Hydro expense to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases using the flexibility provided under the BC Hydro PPA, consistent with previous years. Actual market savings for 2019 and the remainder of 2018 may be higher or lower and will depend on system and market conditions at the time. For 2018, the Company has exceeded the $2.000 million in planned savings, and the 2018 Projection includes an additional $5.787 million in net savings (above the $2.000 million planned savings). Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

The $2.424 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, as well as a $0.150 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and to the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data and, technology company. The method used to forecast market prices and calculate surplus sales is the same as in the Annual Review for 2018 Rates. Overall, the forecast of market prices has a relatively small effect on the overall PPE. The forecast of surplus capacity sales revenue in 2019, which is included in line 3 of Table 4-3, is approximately $9.005 million.

The $4.286 million reduction in Market and Contracted Purchases is due to a forecast reduction in the volume purchased in 2019. Market and Contracted Purchases for 2018 include fixed price contracted purchases, and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2019 Forecast are based on fixed price contracts executed by the Company. As discussed above, there may be opportunities for additional real-time market purchases in 2019 using the flexibility of the PPA purchases and, as identified above, FBC has reduced its expected purchases under the BC Hydro PPA by $2.000 million to account for this.

[16] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Section 1.4.2: The 2013 10 Year Rates Plan. Filed as Ex B-1-1, July 28, 2016

[17] The $1.480 million and $13.071 million total $14.551 million of increased BC Hydro Expense. However, this is before the adjustment to BC Hydro expense to account for within the year market savings. $1.0 million remains in 2018 making the variance between 2018 Projected and 2019 Forecast $1.0 million for a total variance of $13.551 million as given in Table 4-3.

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA, and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2018 Projected PPE, FBC has stored a net total of 16 GWh of entitlement energy, valued at $0.826 million. For the 2019 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's Rate Schedule 21.

Wheeling expense is forecast using the same method as in the Annual Review for 2018 Rates. Table 4-4 below shows FBC's Wheeling Expense for 2018 and 2019.

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,490	2,490	2,400
3	Creston	444	444	471
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.590	$ 4.573	$ 4.514
7	Creston	0.534	0.542	0.577
8	Other	0.048	0.165	0.144
9	Total Wheeling Expense	$ 5.171	$ 5.281	$ 5.235

In 2018 and 2019, ARWA costs are forecast to account for all of FBC's wheeling expense, except for $0.165 million and $0.144 million of OATT and Teck wheeling in 2018 and 2019 respectively. Increased use of both Emergency Wheeling and Teck wheeling in early 2018 caused the 2018 Projected OATT wheeling expenses to exceed Approved.

As shown in Table 4-4 above, 2019 wheeling expense is forecast to decrease by $0.022 million over 2018 Projected. This is a result of decreased Emergency Wheeling use as well as reduced wheeling nominations. Offsetting some of this decrease are increases to ARWA rates on October 1 of both 2018 and 2019, which are based on forecast BC CPI, as well as increases to the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.8 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC CPI.

As shown in Table 4-5 below, the 2019 Forecast water fees are increasing by $0.178 million over 2018 Projected due to increased rates. Water fees are forecast using the same method as in the Annual Review for 2018 Rates.

Table 4-5 below shows FBC's Water Fees for 2018 and 2019.

Table 4-5: Water Fees ($ millions)

Line	Description	Approved 2018	Projected 2018	Forecast 2019
1	Previous Year Entitlement Use (GWh)	1,568	1,577	1,574
2				
3	Water Fees	$ 10.208	$ 10.287	$ 10.465

4.9 SUMMARY

FBC's forecast of power purchase expense is based on FBC's firm resources in place at the time of filing and is consistent with the 2018/19 AECP. FBC will continue to work toward mitigating its power purchase portfolio. Any variances in the costs of power supply, including any power purchase expense decrease due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

5. OTHER REVENUE

FBC is forecasting other revenue for 2019 to be $0.852 million higher than the amounts approved for 2018. The main driver of this increase is Late Payment Charges, which relates to the interest earned from utility customers paying invoices past their due date and which were not included in the 2018 forecast. This income, which is forecast to be $0.852 million in 2018 and $0.861 million in 2019, is also primarily responsible for the increase in the 2018 Projected compared to the approved value.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Apparatus and Facilities Rental	$ 4.736	$ 4.736	$ 4.878
2	Contract Revenue	1.769	1.725	1.766
3	Transmission Access Revenue	1.170	1.170	1.230
4	Interest Income	0.016	0.016	0.016
5	Late Payment Charges	-	0.852	0.861
6	Connection Charges	0.368	0.550	0.376
7	Other Recoveries	0.356	0.560	0.142
8	Total	$ 8.416	$ 9.609	$ 9.268

In the following sections, FBC summarizes its forecasts for each of the line items included in the table above.

5.1 *APPARATUS AND FACILITIES RENTAL*

Apparatus and facilities rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. The 2018 Projected is expected to be in line with 2018 Approved. 2019 revenue is forecast to be higher than 2018 Approved due to escalations in unit rental rates.

5.2 *CONTRACT REVENUE*

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third party work, and the associated management fees earned, fluctuate from year to year based on customer requirements which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing

Policy[18] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2018 Projected is expected to be slightly lower than 2018 Approved due to timing of when contract work is performed, based on customer requirements. FBC's 2019 Forecast revenue is forecast to be slightly higher than 2018 Projected due to labour and material cost escalations, and is in line with 2018 Approved.

5.3 TRANSMISSION ACCESS REVENUE

Transmission access revenue represents charges to customers for transmitting power over the FBC system. Three customers are expected to be using the transmission system in 2018 and 2019. The 2018 Projected is expected to be in line with 2018 Approved, while the 2019 Forecast is expected to increase marginally due to higher nominations of power expected.

5.4 INTEREST INCOME

Interest income is primarily comprised of DSM loan interest income. The Company is continuing to experience a decline in the number of DSM loans, and as a result a corresponding drop in interest income is expected as loans mature.

5.5 LATE PAYMENT CHARGES

FBC has historically not forecast late payment charges as part of its revenue requirement. When these charges were earned, they were flowed through to customers. Beginning with 2019, FBC is forecasting late payment charges as part of Other Revenue, based on an established history of late payment charges being incurred by utility customers paying invoices past their due date. The 2019 Forecast is based on an average of the 2016 and 2017 late payment charges earned. Variances from Approved will continue to be included in the flow-through of Other Revenue.

5.6 CONNECTION CHARGES

Connection charges are calculated based on the fees specified in FBC's rate schedules applied to new customer connections or current customer reconnections. The 2018 Projected connection charges are expected to be higher than 2018 Approved due to a higher number of year-to-date customer connections. The 2019 Forecast is lower than the 2018 Projected due to lower connections expected.

[18] As approved by Order G-5-10A.

5.7 OTHER RECOVERIES

Other recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities. The 2018 Approved and 2018 Projected also includes management fees earned on construction work for a third party that was completed throughout 2017 and 2018. The 2018 Projected is expected to be higher than 2018 Approved due to the timing of when work was completed. The 2019 Forecast does not include any additional management fees for this work as it is expected to be fully completed during 2018.

5.8 SUMMARY

FBC has forecast the other revenue components for 2019 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in other revenue are recorded in the Flow-through deferral account

6. O&M EXPENSE

6.1 *INTRODUCTION AND OVERVIEW*

Under the PBR Plan, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2019, the formula O&M is $56.077 million, representing a 2.376 percent increase from the 2018 formula O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $3.122 million, representing an 18.165 percent decrease from the amount approved for 2018. Overall, the increase in Gross O&M Expense from 2018 Approved to 2019 Forecast is approximately 1.039 percent.

The components of 2019 O&M expense are shown in Table 6-1 below.

Table 6-1: 2019 O&M Expense

Line No.	Description	2019	Reference
1	Formula O&M	$ 56.077	Table 6.2 Line 6
2	Forecast O&M	3.122	Table 6.3 Line 8
3	Total Gross O&M	59.199	
4	Capitalized Overhead (15%)	(8.880)	Section 11, Sch. 20
5	Net O&M	$ 50.319	

In the subsections below, FBC provides further details on its formula and forecast O&M expenses for 2019.

6.2 *FORMULA O&M EXPENSE*

The formula-driven portion of Base O&M starts from a base of the 2018 Approved formula O&M for FBC, escalated by the prior year's inflation less a productivity improvement factor of 1.03 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2018 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 1.475 percent and one-half of the prior year's customer growth is 0.888 percent.

For 2019, the annual operating and maintenance expense under the formula is calculated as:

2018 Approved formula O&M x [1 + (I Factor – X Factor)] x [1 + (0.5 x customer growth)]

Table 6-2 below shows the calculation of the 2019 Formula O&M.

Table 6-2: Calculation of 2019 Formula O&M

Line No.	Description			Reference
1	2018 Approved Formula O&M	$	54.776	FBC 2018 Rates Compliance Filing Sch 20
2				
3	Net Inflation Factor		1.475%	Section 2 Table 2-3
4	Customer Growth Factor		0.888%	Section 2 Table 2-2
5				
6	2019 Formula O&M	$	56.077	Line 1 x (1 + Line 3) x (1 + Line 4)

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

The Formula O&M is then adjusted to add in pension and OPEB expense, insurance premiums, the net costs and savings of FBC's AMI Project, as well as any exogenous factor items (the O&M impacts of the Employer Health Tax and the reduction in Medical Services Plan premiums, and Mandatory Reliability Standards Incremental O&M). FBC has also included in 2018 and 2019 a reduction to O&M due to lower annual inspection costs, which was due to capital refurbishment of two of its generating units. The 2019 amounts are shown in Table 6-3 below along with a comparison to 2018.

Table 6-3: 2019 Forecast O&M ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Pension/OPEB (O&M Portion)	$ 2.659	$ 2.659	$ 1.692
2	Insurance Premiums	1.265	1.246	1.283
3	Advanced Metering Infrastructure Project	(1.139)	(1.139)	(1.161)
4	Mandatory Reliability Standards Incremental O&M	1.070	1.040	0.940
5	Upper Bonnington Old Unit Annual Inspections	(0.040)	(0.040)	(0.040)
6	Employer Health Tax	-	-	0.576
7	MSP Reduction	-	(0.168)	(0.168)
8	Forecast O&M	$ 3.815	$ 3.598	$ 3.122

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account. Variances in insurance premiums, AMI, and the exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expenses for 2019 are based upon actuarial estimates using a range of assumptions as at December 31, 2017 provided by the Company's actuary, Willis Towers Watson. Pension and OPEB expense is segregated into O&M and capital categories as shown in Table 6-4.

Table 6-4: 2018 – 2019 Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2018	Forecast 2019
1	O&M	$ 2.659	$ 1.692
2	Capital	3.630	3.612
3	Total Pension & OPEB Expense	$ 6.289	$ 5.304

Overall, pension and OPEB expense for 2019 is forecast to be $0.985 million lower than the amount approved for 2018. This decrease is primarily due to experience gains revealed in the triennial valuation of the OPEB plan and higher than expected return on assets, partially offset by a decrease in the discount rate.

The majority of the pension and OPEB variance resides in the allocation to O&M since the variance is primarily attributable to the higher expected return on assets which is recognized in O&M.

The 2018 variance between approved and actual pension and OPEB expense and any variance from these forecast 2019 amounts is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period as approved by the Commission in Order G-139-14.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of the PBR formula relates to insurance premium expense allocated to FBC by Fortis Inc.

The 2019 insurance premiums are forecast at $1.283 million, an increase of $0.018 million or 1.4 percent from what was approved for 2018. The 2019 Forecast is calculated by taking the known annual insurance premium of $1.120 which is applicable to the first six months of 2018 and escalating that amount by five percent for the remaining six months.[19] FBC uses a five percent escalation unless there are indications which suggest significant increases are forthcoming as a result of loss history for the Company or the industry as a whole.

6.3.3 AMI Project

Incremental O&M costs related to the implementation of the AMI project are being offset by post-implementation savings, resulting in a net decrease to O&M expense during the PBR period. Because of the high variability of AMI costs and savings during the implementation period, net AMI costs, including the costs of AMI-enabled billing options, are forecast and tracked outside of the PBR formula.

[19] $1.120 million/2 = $0.560 million x 1.05 = $0.588 million. $0.560 million + $0.588 million + $0.135 million annual firefighting premium = $1.283 million.

Table 6-5 below compares 2014 through 2019 net AMI savings to the net savings forecast in the AMI CPCN application.

Table 6-5: AMI Costs and Savings ($ millions)

Line No.		2014-2017			2018			2019	
1		Actual	Approved	CPCN[1]	Projected	Approved	CPCN[1]	Forecast	CPCN[1]
2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3									
4	AMI Costs	$ 5.202	$ 5.814	$ 6.792	$ 2.015	$ 2.015	$ 1.960	$ 2.055	$ 1.951
5	AMI Savings	(7.137)	(7.688)	(10.439)	(3.153)	(3.153)	(4.424)	(3.216)	(4.244)
6	Net AMI Costs/(Savings)	$ (1.935)	$ (1.874)	$ (3.647)	$ (1.139)	$ (1.139)	$ (2.464)	$ (1.161)	$ (2.293)
7									
8	[1] CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14								

As reported previously, AMI-related costs and savings from 2014 to 2017 lag those estimated in the AMI CPCN primarily due to delayed project timing following an extensive CPCN review process and the Commission's directive to file for approval of an opt-out program prior to meter installation. The AMI project was substantially completed during 2016, such that 2017 was the first year of fully realized costs and savings for the AMI project.

As shown in Table 6-5 above, the 2018 Projected costs are approximately as forecast in the CPCN application.

As also shown in Table 6-5 above, the 2018 forecast savings of $3.153 million are approximately $1.271 million lower than the CPCN forecast of $4.424 million. This variance is driven by meter reading, Measurement Canada compliance savings, and other smaller factors as explained below.

6.3.3.1 Meter Reading

The CPCN forecast was a comparison of the savings that would be achieved with the AMI project to the costs that would otherwise be incurred to support the continuation of a manual meter reading program. As such, the AMI CPCN forecast savings required a cost forecast of continuing with manual meter reading. The manual meter reading cost forecasts used in the CPCN for 2013 and 2014 (the last full years of manual meter reading) were higher than the costs actually experienced in those years. These savings resulted largely from efficiencies found in absorbing the City of Kelowna manual meter reading work. As a result, the savings potential was diminished in 2015 and beyond.

CPCN forecast costs for meter reading were also based in part on the forecast number of customers. This CPCN customer count forecast averaged 1.9 percent growth per year between 2014 and 2016 (the last year of comparative meter reading costs), which was higher than the 1.3 percent actually experienced. The 2018 forecast customer count in the CPCN application (those that would have required manual meter reading in the absence of AMI) is expected to be higher by about 6,600 customers than the actual number of customers based on experience to mid-2018.

In total, the meter reading savings contribute approximately $0.700 million of the total AMI savings variance in 2019.

6.3.3.2 Measurement Canada Compliance

One of the benefits of replacing the majority of the meter fleet with AMI meters was a reduction in Measurement Canada compliance costs. As with meter reading, forecasting these savings required a forecast of the cost of meter exchanges that would have been required in the absence of AMI. The CPCN application forecast that 2018 would be the peak year in terms of the number of electromechanical and non-AMI digital meter replacements due to the Measurement Canada SS-06 regulation (in the absence of AMI). These non-AMI compliance costs were estimated to be $0.400 million higher than the forecast of Measurement Canada cost for 2018. This $0.400 million avoided cost does not result in a reduction to 2019 O&M costs, but will still result in lower rates for customers than in the absence of AMI.

6.3.3.3 Other Factors

Other factors contributing to the $1.271 million AMI Savings variance include:

- Approximately $0.100 million lower savings due to higher post-AMI manual disconnect and reconnect costs than forecast. The higher post-AMI costs are due to not forecasting an increase in the unit cost of manual disconnects and reconnects at substantially lower post-AMI volumes.
- Approximately $0.100 million lower savings due to lower pre-AMI Measurement Canada compliance exchange costs than forecast. As with the lower pre-AMI meter reading costs discussed above, this reduced the post-AMI savings potential.

6.3.4 MRS Incremental Operating Expense

FBC forecasts that it will incur $0.940 million in incremental O&M expense in 2019 related to the adoption of new and revised standards as summarized in Table 6-6 and described below.

Table 6-6: MRS Incremental O&M Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Assessment Report No. 8	$ 0.540	$ 0.540	$ 0.540
2	Assessment Report No. 10	0.180	0.150	0.400
3	2018 Compliance Audit	0.350	0.350	-
4	Forecast O&M	$ 1.070	$ 1.040	$ 0.940

6.3.4.1 Assessment Report No. 8

In 2016 FBC began to incur incremental O&M and capital costs for MRS in compliance with Order R-38-15 dated July 24, 2015. In Order R-38-15, the Commission adopted 34 reliability

standards and the NERC (North American Electric Reliability Corporation) Glossary of Terms (NERC Glossary) as recommended for adoption by BC Hydro in its MRS Assessment Report No. 8.

As explained in Section 12.2.2, the incremental costs in 2018 for MRS compliance qualify for exogenous factor treatment. This treatment is consistent with the Commission's determination in Orders G-202-15, G-8-17, and G-38-18 that FBC's 2016, 2017 and 2018 costs required for the adoption of MRS pursuant to Order R-38-15 met the criteria for an exogenous event under the PBR Plan.

FBC is continuing to track the incremental O&M and capital costs associated with compliance with Order R-38-15 and flowing them through to rates outside of the formulas.

FBC's 2018 projection of incremental O&M expenses is $0.540 million which is equal to the Approved. The 2018 expenses include ongoing efforts to maintain processes and systems that address physical and cyber security controls, continuous monitoring, change management, patch management and vulnerability assessments. The effort is primarily labour and annual licensing fees required to maintain compliance with Critical Infrastructure Protection version 5 (CIP V5).

The forecast expenditures for 2019 of $0.540 million reflect the ongoing effort to maintain compliance. These costs will continue in future years. Any variances from Projected and Forecast amounts for MRS compliance will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

6.3.4.2 Assessment Report No. 10

BC Hydro issued Assessment Report No. 10 (AR10)[20] on May 1, 2017 recommending adoption of 35 of the 38 standards and 40 of the 43 terms from the NERC Glossary that were assessed. The Commission issued Order R-39-17 on July 26, 2017 which adopted and determined the effective dates for the recommended 35 of the 38 standards. Of the 38 standards and respective NERC Glossary terms assessed by FBC, approximately 15 percent of the standards have associated costs.

FBC's 2018 projection of incremental O&M expenses is $0.150 million, which is lower than the Approved by $0.030 million. FBC will continue the process of determining the strategy and detailed scope and select the tools and support systems required to comply with the revised standards, and will be completing the evaluation in fall of 2018 and initiating the procurement process in Q4 of 2018. The conclusion of the process will accurately define the expenditures for 2019 and future years.

[20] The Commission adopted 15 Revised Standards and 10 NERC Glossary Terms addressed in BC Hydro's Assessment Report No. 9 by (AR9) Order R-32-16A on November 9, 2016. Incremental costs for FBC to achieve and maintain compliance with standards resulting from AR9 did not meet the financial threshold for Z-factor treatment.

O&M expenditures associated with AR10 for 2019 are forecast to be $0.400 million. The expenditures are primarily for resource additions in System Operations that will be required to ensure full compliance by October 1, 2020. The resources require significant development and training to be fully functional in performing real-time pre- and post-contingency assessments every 30 minutes, meeting outage coordination requirements, and implementing outage scheduling timelines and next day studies by the effective date.

As noted above, FBC will continue to evaluate and determine how to best achieve compliance with AR10. Future expenditures associated with AR10 will be addressed in future filings. Any variances from the 2018 Projected and 2019 Forecast amounts for MRS compliance will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

6.3.4.3 2018 Compliance Audit

FBC's triennial MRS audit will conclude in August 2018. Notification of the audit was received on April 24, 2018, and the scope of the audit covers all of FBC's registered functions which include both Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) standards. The formal audit with the Western Electricity Coordinating Council (WECC) auditors was conducted over a two-week period from July 23 to August 3, consisting of a one week off-site data review and a one week on-site visit to conduct interviews, clarify outstanding questions and visit specific Facilities. Preparation and submission of evidence was required several months in advance of the two-week formal audit period. A total of 22 standards will be assessed and evidence submitted to WECC. FBC anticipates receiving a draft report of the audit assessment and findings in September 2018. In Order G-139-14 the Commission confirmed that as a non-recurring expenditure, MRS audits should not be included in Base O&M[21].

The Company continues to work towards maintaining MRS compliance and forecasts the costs related to the 2018 audit to be $0.350 million.

6.3.5 Annual Inspection Costs for Upper Bonnington Old Units

The Upper Bonnington (UBO) Old Units Refurbishment project commenced in 2017. UBO Unit 3 was refurbished in 2017, the refurbishment of Unit 4 is proceeding in 2018; Unit 1 is planned for 2019 and Unit 2 for 2020. The Company will not carry out the annual inspections on the units while out of service for refurbishment. This results in an estimated savings of $0.040 million per unit.

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 unit will once again undergo annual inspections following refurbishment. Therefore, the level of Base O&M expenditures is not impacted on an

[21] PBR Decision, page 238.

ongoing basis. For this reason, the O&M reduction is outside of the formula O&M amount. Because these are avoided costs, there will not be a future true-up of this value.

6.3.6 Employer Health Tax (EHT)

The EHT will come into effect on January 1, 2019, as announced in the February 2018 provincial budget. The EHT qualifies as an exogenous factor, as described in Section 12.2.1. The EHT is a payroll tax, some details of which are still to be determined through pending legislation. FBC's current forecast for EHT in 2019 is $1.200 million, of which $0.576 million is included in labour loadings to O&M expense, and the remainder to capital. Variances from forecast will be recorded and returned to, or recovered from customers, by way of the Flow-through deferral account in 2020.

Table 6-7 below provides the O&M and capital components of forecast EHT in 2019.

Table 6-7: 2018 – 2019 EHT Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	O&M	-	-	$ 0.576
2	Capital	-	-	0.624
3	Total EHT Expense	-	-	$ 1.200

6.3.7 Medical Services Plan (MSP) Premium Reduction

Effective January 1, 2018, provincial MSP premiums were reduced by 50 percent. This reduction qualifies as an exogenous factor, as described in Section 12.2.2. FBC forecasts a reduction in O&M expense of $0.350 million in each of 2018 and 2019, of which $0.168 will be a reduction of labour loadings in O&M expense, and the remainder a reduction to capital expenditures. Variances from forecast will be recorded and returned to, or recovered from customers by way of the Flow-through deferral account in 2019 and 2020.

Table 6-8 below provides the O&M and capital components of the forecast MSP premium reduction in 2018 and 2019.

Table 6-8: 2018 – 2019 MSP Premium Reduction ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	O&M	-	$ (0.168)	$ (0.168)
2	Capital	-	(0.182)	(0.182)
3	Total MSP Premium Reduction	-	$ (0.350)	$ (0.350)

6.4 GENERATION UNIT INSPECTIONS

As directed by the Commission in Order G-139-14, FBC provides in this section a review of its actual expenses for generation major unit inspections in the Annual Review.

The costs related to generation major unit inspections are included within formula Base O&M. These costs are for periodic major inspections of FBC's generating units, which have been the subject of upgrades and/or life extensions beginning in 1998. The inspections are expected to cost approximately $0.350 million per unit, depending on unit condition. The majority of FBC's generating units have similar characteristics and, as such, the estimate of $0.350 million is based on typical equipment in average operating condition. FBC expects to undertake one major unit inspection per year.

The Commission indicated on page 197 of the PBR Decision that the actual expenditures related to generation unit inspections should be monitored through the Annual Review process:

> Given the background and assurances provided by FBC, the Commission Panel finds that the proposal to include the $350,000 within the Base O&M is reasonable and is not persuaded there is a need to make it a flow through item at this time. However, in consideration of the concerns raised and the magnitude of the estimate, actual expenditures should be monitored through the Annual Review process.

FBC completed its major unit inspection on Upper Bonnington Unit 5 in 2017 at a cost of $0.349 million. The scope of the inspection included dismantling of the unit to the shaft coupling, removing the rotor, performing overhauls on otherwise inaccessible systems such as the guide bearing, thrust bearing and brakes, performing in-depth mechanical and electrical inspections, and cleaning.

Unit inspections provide FBC with the opportunity to perform maintenance and condition assessment on components that are not accessible in normal operation. This allows FBC to address condition deterioration causes to ensure that the generating unit continues to be operated in a safe and efficient manner and that design life expectancy is achieved. These continued inspections enable the generating units to remain a reliable source of generation for FBC customers.

FBC plans to perform a unit inspection on South Slocan Unit 2 in Q4 of 2018 at an estimated cost of $0.366 million and on Lower Bonnington Unit 3 in 2019 at an estimated cost of $0.374 million. The increase in costs is due mainly to an increase in labour rates and also FBC undertaking slightly more work on these Units due to their condition.

6.5 NET O&M EXPENSE

Net O&M expense is Gross O&M less capitalized overhead. As approved by the Commission in Order G-139-14, the capitalized overhead rate is 15 percent for FBC. After capitalized overhead, the net O&M expense is $50.319 million.

6.6 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2018 to 2019 is approximately 1.039 percent. The formula-driven O&M is increasing at a rate of 2.376 percent, and forecast O&M is 18.165 percent lower than Approved 2018. The capitalized overhead rate remains unchanged from 2018.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2019 Rate Base for FBC is forecast to be $1.341 billion. Rate Base is composed of mid-year net plant in service, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital and the generation plant acquisition adjustment[22].

The 2019 Rate Base of FBC includes the full-year impacts of the 2018 closing projected plant balances as well as the mid-year impact of the following amounts:

- Mid-year impact of capital additions, net of Contributions in Aid of Construction (CIAC) additions, resulting from regular capital expenditures of $43.321 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $37.972 million;
- Full-year impact of the $14.775 million from the Ruckles Substation Rebuild Project and the second of four generating units completed under the Upper Bonnington (UBO) Old Units Refurbishment Project; and
- Full-year impact of the capital formula dead band adjustment of $8.372 million[23] as discussed in Section 1.4.3.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $29.791 million.

Details of the 2019 forecast plant balances can be found in Section 11 Schedules 5 through 9.

7.2 2019 REGULAR CAPITAL EXPENDITURES

Under the PBR Plan, FBC's regular capital expenditures are primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2019, the formula capital is $44.859 million, representing a 2.376 percent increase from 2018, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $7.771 million, representing a 96.984 percent increase from 2018, primarily due to higher incremental capital expenditures for MRS and AMI sustainment capital. Overall, regular capital expenditures are forecast to increase from 2018 to 2019 by 10.190 percent. The components of 2018 regular capital expenditures are shown in Table 7-1 below.

[22] The utility plant acquisition adjustment relates to the 1982 purchase of plants 2, 3, and 4 and is being amortized over a period of 64 years.

[23] Section 11, Schedule 6.1, Line 14

Table 7-1: 2019 Regular Capital Expenditures ($millions)

Line No.	Description			Reference
1	Formula Capital Expenditures	$	44.859	Table 7.2 Line 6
2	Forecast Capital Expenditures		7.771	Table 7.3 Line 6
3	Total Regular Capital Expenditures	$	52.630	

In the subsections below, FBC provides further details on its formula and forecast capital expenditures for 2019.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2018 approved formula capital, escalated by the prior year's inflation less a productivity improvement factor of 1.03 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2019 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 1.475 percent, and one-half of the prior year's average customer growth is 0.888 percent. In accordance with Order G-139-14, regular capital expenditure amounts will not be rebased to actual amounts during the PBR term, except that if the capital dead band is exceeded, FBC will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

For 2019, the annual capital expenditures under the formula are initially calculated as:

2019 Capital = 2018 Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth]

Table 7-2 below shows the calculation of the resulting 2019 formula capital expenditures.

Table 7-2: Calculation of 2019 Formula Capital Expenditures

Line No.	Description			Reference
1	2018 Approved Formula Capital Expenditures	$	43.818	FBC 2018 Rates Compliance Filing Sch. 4
2				
3	Net Inflation Factor		1.475%	Section 2 Table 2-3
4	Customer Growth Factor		0.888%	Section 2 Table 2-2
5				
6	2019 Formula Capital	$	44.859	Line 1 x (1 + Line 3) x (1 + Line 4)

7.2.2 Regular Capital Expenditures Forecast Outside the Formula

To calculate total regular capital expenditures, the formula capital expenditures are adjusted to add in pension and OPEB expense, AMI sustainment capital and capital expenditures that qualify for exogenous treatment (MRS, EHT and MSP reduction) as discussed in Section 12.2 of the Application. These amounts are shown in Table 7-3 below along with a comparison to 2018.

Table 7-3: 2019 Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Pension/OPEB (Capital Portion)	$ 3.630	$ 3.630	$ 3.612
2	AMI Sustainment Capital	0.265	0.324	0.937
3	Mandatory Reliability Standards Incremental Capital	0.050	0.050	2.780
4	Employer Health Tax	-	-	0.624
5	MSP Reduction	-	(0.182)	(0.182)
6	Forecast Capital Expenditures	$ 3.945	$ 3.822	$ 7.771

Each of the items forecast outside of the formula is described further below.

- The Pension and OPEB forecast of $3.612 million represents the forecast capital portion of the total Pension and OPEB costs for 2019. Pension and OPEB costs are described in Section 6.3.1.
- AMI Sustainment Capital of $0.937 million represents the costs of sustainment capital associated with IT hardware, licensing, and support. These sustainment capital requirements result from the required support and upgrade of software utilized by the AMI project, such as the meter data management system, the head end system and network management system, and ongoing software licensing and support requirements.
- FBC forecasts that it will incur $2.780 million in incremental capital related to the adoption of new and revised MRS standards for AR8 and AR 10, as explained in Section 6.3.4. The treatment of this amount as an exogenous factor is discussed in Section 12.2.3. The 2019 capital expenditure is a combination of one-time capital for AR10 ($2.700 million) based on its evaluation to date, and sustainment capital for AR8 ($0.080 million). The capital expenditure related to AR10 includes necessary redundant hardware and software systems which are within the boundaries of the SCADA network, so all Critical Infrastructure and Protection standards will apply. Additional sustaining capital will be required beyond 2019 for ongoing support for the hardware and software additions, including annual upgrades and minor additions that may be required to the infrastructure and systems implemented as a result of the AR 8 and AR10 standards. .
- The EHT forecast of $0.624 million is the forecast capital portion of the total EHT costs for 2019. These costs are described in Sections 6.3.6. and 12.2.1
- The capital portion of the MSP premium reduction is forecast at $0.182 million in each of 2018 and 2019. The MSP premium reduction is discussed in Sections 6.3.7 and 12.2.2.

7.3 CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Also forecast outside of the formula are any capital expenditures related to approved CPCNs and other projects which were determined by Order G-80-16 to be outside of the formula capital expenditures and eligible for flow-through treatment.

For 2019, FBC is forecasting capital expenditures related to the UBO Refurbishment Project and the Corra Linn Dam Spillway Gate Replacement Project. Of these projects, the portion of the UBO Project attributable to the refurbishment of Unit 4 will be included in rate base in 2019. Additionally, the Ruckles Substation Project, which is expected to be completed in 2018, will be included in rate base in 2019.

Each of these projects is described further below[24].

- The UBO Project was approved by Order G-8-17 and involves the refurbishment of the more than 100 year old generating Units 1 – 4 (the Old Units). The refurbishments will take place over four years at an estimated cost of $31.783 million, of which $7.822 million will be incurred in 2019. The UBO Project Status Report is included as Appendix C.
- The Corra Linn Dam Spillway Gate Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be completed in 2021 at a cost of $66.844 million, with $14.459 million of this amount incurred in 2019.
- The Ruckles Substation Rebuild Project was approved by Order G-8-17 and involves rebuilding the existing substation in Grand Forks. The project will be completed during 2018 and is estimated to cost $6.913 million. The Ruckles Substation Rebuild Project Status Report is included as Appendix D.

7.4 2019 PLANT ADDITIONS

The 2019 Plant Additions are comprised of FBC's 2019 regular capital expenditures from section 7.2 above, Unit 4 of the UBO Project, the Ruckles Substation Rebuild Project, the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end, AFUDC and overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Schedule 5 in Section 11.

[24] Costs inclusive of AFUDC and cost of removal.

Table 7-4: Reconciliation of Capital Expenditures to Plant Additions ($millions)

Line No.	Description			Reference
1	Formula Capital Expenditures	$	44.859	Table 7-2
2	Forecast Capital Expenditures		7.771	Table 7-3
3	Total Regular Capital Expenditures		52.630	
4				
5	Capitalized Overhead		8.880	Table 6-1
6	Direct Overhead		5.000	Section 11, Sch. 5, Line 19
7	AFUDC		0.692	Section 11, Sch. 5, Line 20
8	Cost of Removal charged to Accumulated Depreciation		(2.633)	Section 11, Sch. 5, Line 21
9	Total Regular Additions to Plant		64.569	
10				
11	Special Projects and CPCN Capital Expenditures		20.199	Section 11, Sch. 5, Line 27
12	Special Projects and CPCN AFUDC		2.082	Section 11, Sch. 5, Line 28
13	Special Projects and CPCN Cost of Removal		(3.084)	Section 11, Sch. 5, Line 29
14	Special Projects and CPCN Work in Progress		(4.422)	Section 11, Sch. 5, Line 31
15	Special Projects and CPCN Additions to Plant		14.775	
16				
17	2019 Plant Additions	$	79.344	

7.5 CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Rate base is reduced by CIAC. Gross CIAC is composed of opening contributions plus additions during the year. 2019 CIAC additions are forecast at $8.876 million. The year-end CIAC balances net of accumulated amortization are $123.857 million in 2018 (projected) and $128.637 million forecast in 2019.

7.6 ACCUMULATED DEPRECIATION

The rate base of FBC includes the accumulated depreciation of plant in service, which is increased through depreciation expense, and decreased through retirements.

The depreciation rates used for 2019 are the rates that have been approved by Orders G-202-15 and C-7-13 and include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved in Commission Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2019 depreciation expense is calculated as $60.156 million.

7.7 RATE BASE DEFERRED CHARGES

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $13.458 million in 2019 and this balance is driven largely by the balances in deferral accounts for DSM, Pension and OPEB funding liability, deferred debt issue expense and unamortized meter costs arising from the AMI project, which were deferred pursuant to Order C-7-13. FBC is not proposing any new rate base deferral accounts for 2019.

Based on amortizing the opening deferral account balances using the approved amortization periods, the 2019 amortization expense for rate base deferral accounts is calculated as $5.313 million.[25]

7.8 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

7.8.1 Cash Working Capital

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag).

FBC's revenue lag for each customer class is the sum (weighted by the relative proportion of monthly- to bimonthly-billed customers in the class) of:

- The consumption lag, which is the number of days between the consumption of energy and the date the customer's meter is read or estimated;
- The processing lag, which is period between the date the customer meter is read or estimated and the date the bill to the customer is prepared; and
- The clearing lag, which is the period between the customer billing date and the when the funds are received from the customer.

The revenue lag associated with sales revenue is primarily a function of the frequency of billing. The majority of residential and commercial customers are currently being billed on a bi-monthly basis which corresponds with the bi-monthly manual meter reading schedule. Following the completion of FBC's AMI project, the Company is offering a new billing option to provide customers with monthly billing based on verified meter reads. Depending on the number of customers choosing this option, the revenue lag component of working capital may be reduced. In its Decision and Order G-16-14 approving FBC's proposed AMI-Enabled Billing Options, the Commission directed that FBC must flow through any incremental working capital benefits to customers by way of the Flow-through deferral account approved in Order G-139-14.

[25] Section 11, Schedule 11 Line 17 Column 6.

7.8.1.1 AMI Working Capital Impact

The impact on working capital due to the AMI Project results from changes in the proportion of monthly-billed to bi-monthly-billed customers. Based on the change in the proportion of monthly-billed customers each year, FBC quantifies the impact on working capital and will record the variance in the Flow-through deferral account. In 2017, which is the most recent complete year of billing data available, the impact of AMI on cash working capital results in a decrease of $0.024 million to revenue requirements, which will be returned to customers in 2019. The calculation of the revenue requirements impact is provided below.

From a comparison of columns c and f in Table 7-5 below it can be seen that for the two largest customer classes, residential and commercial, the proportion of customers receiving monthly rather than bi-monthly bills was greater in 2017 than forecast (approved)[26]. The periods between taking service and meter reading, and between billing and collection are shorter for customers on a monthly billing cycle. Hence, the total revenue lag days is lower than calculated in the approved cash working capital calculation.

Table 7-5: Calculation of 2017 Revenue Lag

Line No.	Customer Class	Service Period to Meter Read		Approved			Actual			Meter Read to Billing
				Proportion Billed		Consumption	Proportion Billed		Consumption	
		Monthly	Bimonthly	Monthly	Bimonthly	Lag	Monthly	Bimonthly	Lag	Processing Lag
		a	b	c	d	e=a*c+b*d	f	g	h=a*f+b*g	i
1	Residential	15.2	30.4	13.5%	86.5%	28.3	16.2%	83.8%	27.9	1.0
2	Commercial	15.2	30.4	18.9%	81.1%	27.5	21.6%	78.4%	27.1	1.0
3	Wholesale	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
4	Industrial	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
5	Lighting	15.2	30.4	42.7%	57.3%	23.9	41.4%	58.6%	24.1	1.0
6	Irrigation	15.2	30.4	16.7%	83.3%	27.9	17.0%	83.0%	27.8	1.0
7										
8										
9		Billing to Collection		Approved			Actual			Approved / Actual
10				Proportion Billed		Clearing	Proportion Billed		Clearing	
11		Monthly	Bimonthly	Monthly	Bimonthly	Lag	Monthly	Bimonthly	Lag	Total Lag Days
12		j	k	l=c	m=d	n=j*l+k*m	o=f	p=g	q=j*o+k*p	r=e+i+n / s=h+i+q
13	Residential	17	22	13.5%	86.5%	21.3	16.2%	83.8%	21.2	50.7 / 50.1
14	Commercial	17	22	18.9%	81.1%	21.1	21.6%	78.4%	20.9	49.6 / 49.0
15	Wholesale	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2 / 33.2
16	Industrial	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2 / 33.2
17	Lighting	17	22	42.7%	57.3%	19.9	41.4%	58.6%	19.9	44.8 / 45.0
18	Irrigation	17	22	16.7%	83.3%	21.2	17.0%	83.0%	21.2	50.0 / 50.0

Table 7-6 below recalculates 2017 cash working capital assuming the revenue lags as of December 31, 2017. Cash working capital is reduced by $0.293 million, therefore reducing rate base by the same amount.

[26] The proportion of residential and commercial customers billed monthly also increased over 2016 actuals, when 14.6 percent and 19.6 percent of customers, respectively, were billed monthly.

Table 7-6: AMI Adjustment to 2017 Cash Working Capital ($ million)

Line No.	Description	2017 at Revised Rates	Lag (Lead) Days	Extended	Average Lag (Lead) Days	Reference (2017 Evidentiary Update)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 187.578	50.1	$ 9.403		
4	Commercial Tariff Revenue	86.254	49.0	4.230		
5	Wholesale Tariff Revenue	48.498	33.2	1.610		
6	Industrial Tariff Revenue	33.501	33.2	1.112		
7	Lighting Tariff Revenue	2.873	45.0	0.129		
8	Irrigation Tariff Revenue	3.424	50.0	0.171		
9						
10	**Other Revenue**	8.056		0.249		Section 11, Schedule 14, Lines 10 - 14
11						
12	Total	$ 370.184		$ 16.904	45.7	
13						
14	**EXPENSES**	$ 267.481		$ 10.323	(38.6)	Section 11, Schedule 14, Line 34
15						
16	Net Lag (Lead) Days				7.1	
17						
18	Total Expenses				$ 267.481	
19						
20	Cash Working Capital, Revised Lag Days				$ 5.203	
21						
22	Cash Working Capital in 2016 Rates				$ 5.496	Section 11, Schedule 14, Line 40
23						
24	Reduction in Cash Working Capital				$ (0.293)	

Finally, Table 7-7 calculates the revenue requirements impact of the $0.293 million reduction in rate base by applying the pre-tax weighted average cost of capital. The adjustment of $0.024 million (credit) is included in the additions to the Flow-through deferral account, as shown in Section 12, Table 12-4 at line 26.

Table 7-7: Revenue Requirements Impact of AMI Adjustment to Cash Working Capital ($ million)

Line No.	Description	Weight	Pre-Tax Rate	Adjustment for Cash Working Capital	Reference (2017 Evidentiary Update)
1	Long Term Debt	59.13%	5.18%	$ (0.009)	Section 11, Schedule 26, Line 1
2	Short Term Debt	0.87%	7.45%	(0.000)	Section 11, Schedule 26, Line 2
3	Common Equity	40.00%	12.36%	(0.014)	Note 1
4					
5					
6	Weighted Average	100.00%	8.07%	$ (0.024)	Column 2 x Column 3 x $0.586 million

7.8.2 Other Working Capital

Other working capital includes the monthly averages of uncollectible accounts, inventory of materials and supplies, and DSM and employee loans, less customer deposits and sales taxes. Forecast values for these items, except for customer loans for DSM projects which are forecast separately, are generally based on the average of the actual amounts in the two prior years and are shown in Section 11, Schedule 13.

7.9 *SUMMARY*

FBC's rate base includes the impact of both formula-driven capital expenditures and those capital expenditures that are forecast outside of the formula and CPCNs and Special Projects, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts

for all of its rate base deferral accounts in its financial schedules in Section 11. Finally, the rate base includes other working capital, composed of customer deposits and loans and other smaller components.

8. FINANCING AND RETURN ON EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-75-13 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. The 2019 forecast for financing costs, including the interest expense on issued long and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC Rate for 2019 (which is equal to its after-tax weighted average cost of capital) is 5.89 percent. Variances in the interest expense recovered in rates will be recorded in the Flow-through deferral account for return to or recovery from customers in the following year.

8.2 *CAPITAL STRUCTURE AND RETURN ON EQUITY*

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the Commission from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16.

FBC has therefore prepared this Application using an ROE of 9.15 percent and a common equity percentage of 40 percent.

8.3 *FINANCING COSTS*

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long-term debt and short-term (unfunded) debt.

8.3.1 Long-term Debt

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 percent for a term of 32 years. The net proceeds were used to repay existing indebtedness. FBC does not plan to issue any long-term debt in 2018 or 2019. The exact timing, amount and rate of any future issuances will depend on market conditions at the time of issuance and capital expenditure requirements. sVariances in interest expense related to the timing and amount of the issuance of the debt or the rate at which it is issued will be captured in the Flow-through deferral account.

8.3.2 Short-term Debt

FBC obtains short-term funding primarily through the issuance of Bankers' Acceptances or prime lending rate margin loans, both drawn on its $150 million operating credit facility, which matures in April 2023. The operating credit facility, along with a $10 million overdraft facility,

provides FBC with required liquidity should there be constraints issuing debt to fund FBC's capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on forecast long-term debt issuances are based on current indicative rates, on the assumption that FBC's credit ratings of FBC are maintained and that credit spreads will remain at current levels in the future. As discussed above, FBC does not intend to issue long-term debt in 2019.

FBC's short-term borrowing rate is based on the rate at which it issues Bankers' Acceptances (or the Canadian Dealer Offered Rate or CDOR) plus an Acceptance Fee Rate, and on the Prime Lending Rate. Since CDOR is not forecast by economists, a forecast needs to be derived by FBC. Therefore, the Company must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. The Company then adds the Acceptance Fee Rate of 1.0 percent, based on the pricing in the Company's operating credit facility agreement based on its current credit ratings.

The forecast weighted average short-term rate, prior to including standby fees and financing fees, has increased from the 2018 projected rate of 3.55 percent to a 2019 forecast rate of 4.12 percent.

The short-term interest rate forecasts are shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast[27]

Line No.	Description	Projected 2018	Forecast 2019
1	3 month T-Bills[1]	1.36%	2.05%
2	Spread to CDOR	0.42%	0.42%
3	Acceptance Fee Rate	1.00%	1.00%
4	Bankers' Acceptance Rate	2.78%	3.47%
5			
6	add: Standby Fee on Undrawn Credit[2]	0.31%	0.24%
7	add: Financing fees[3]	0.46%	0.41%
8	FBC Short-term Interest Rate	3.55%	4.12%

[27] The 2018 approved short term rate for FBC was 3.45%, inclusive of standby fees and financing fees.

Note 1 - 3-Month T-Bill rate for 2018 based on a composite of actual historical rates up to March 31, 2018 and forecasted rates for the remainder of the year.

Note 2 - Amounts undrawn on the credit facility are subject to a standby fee, which is estimated to be 31 basis points in 2018 and 24 bps in 2019. In order to incorporate the standby fee into the short-term interest rate, the standby fee as shown reflects the amount payable had it been converted to a rate to be applied to the amount of operating credit facilities which has not been drawn upon through BAs.

Note 3 - Also included in the total interest expense forecast are financing fees which are fixed in nature. These financing fees consist of banking agreement renewal fees, annual lender and agency fees, demand line interest and other minor interest charges such as interest due to customers on outstanding security deposits.

The all-in short term interest rate is forecast to increase in 2019 primarily driven by an expected increase in the Banker's Acceptance rate in 2019 Forecast as compared to 2018 Projected. Included in short-term interest expense are standby fees and financing fees, which do not directly correspond with the amount of short-term debt issued. As the average short-term debt balance is expected to be greater in 2019 Forecast compared to 2018 Projected, when the absolute dollar amount of standby fees and financing fees are converted into a 2019 short-term interest rate, the contribution of these fees to the overall short-term rate decreases compared to 2018 as a result of dividing these fees over the lower forecast balance of 2018 short-term debt.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long-term debt and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance and then adding financing fees. Long-term debt interest expense is determined using the straight line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2019 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

FBC's Flow-through deferral account captures the variances in interest expense for return to or recovery from customers in the following year.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC Rate for 2019 (which is equal to its after-tax weighted average cost of capital) is 5.89 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2019

Line No.	Description	Weight	Pre-Tax Rate	After-Tax Rate
1	Long Term Debt	54.79%	5.18%	3.78%
2	Short Term Debt	5.21%	4.12%	3.00%
3	Common Equity	40.00%	12.53%	9.15%
4				
5	Weighted Average	100.00%	8.07%	5.89%

8.4 *SUMMARY*

FBC's capital structure and ROE have been forecast for 2019 at the same percentages as approved for 2018. FBC's financing costs on rate base are primarily determined by embedded rates on long-term debt. The calculated short-term debt rate is forecast to increase in 2019, as a result of the underlying cost drivers, but this increase is partially offset by the mechanics of the calculation, with standby fees and fixed financing fees being applied to a greater forecast balance of short term debt in 2019.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis that is consistent with prior years. In 2019, property taxes are forecast to increase by 0.2 percent from 2018 Approved, while income tax is forecast to decrease by 20.0 percent compared to 2018 Approved. Any variances from the forecast of property taxes and income tax included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.2 PROPERTY TAXES

Property taxes for 2019 of $16.713 million incorporates Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Generating Plant	$ 3.080	$ 3.015	$ 3.082
2	Transmission and Distribution	6.672	6.471	6.705
3	Substation Equipment	3.731	3.663	3.741
4	Land and Buildings	1.192	0.983	1.019
5	In-Lieu	2.009	2.011	2.166
6	Total Property Taxes	$ 16.684	$ 16.143	$ 16.713
7				
8	Forecast Change from Approved 2018			0.2%
9	Forecast Change from Projected 2018			3.5%

As shown in the table above, in 2019 property taxes are forecast to increase by 0.2 percent from 2018 Approved, and to increase 3.5 percent compared to 2018 Projected. In general, the increase from 2018 Projected is primarily due to the following:

3. **Changes in Tax Rates.** On average:
   a) Municipal rates are not expected to change;
   b) School rates are not expected to change;
   c) Rural rates are expected to decrease by 0.75 percent;
   d) Tax rates on First Nations are expected to increase 0.50 percent; and
   e) Other rates are expected to increase by 1.25 percent.

4. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 7.7 percent over Projected based on actual revenues to be reported. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

5. ***Changes in Assessed Values***. Forecast changes in the assessed values of FBC's property are based on anticipated increases by BC Assessment at the time the forecast was developed. These include:

   a) A 3.0 percent increase in assessed values for distribution lines and transmission lines;

   b) A 1.0 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 1.5 percent increase in assessed values for substations calculated using legislated cost manuals for valuing substations; and

   d) Land value changes which are expected to range from a 3.0 percent increase in the assessed value for right of ways to a 5.0 percent increase in the market value for properties owned in fee simple.

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.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission-approved past practice, at the corporate tax rate of 27 percent for 2019, which is unchanged from 2018. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and will be updated each year as part of the annual rate setting process.

Income tax is forecast to decrease in 2019 by $1.922 million or 20.0 percent compared to 2018 Approved. This decrease is primarily due to the amortization of the regulatory Flow-through accounts refunded to customers, in addition to the generally offsetting impacts of higher before-tax earnings and other tax timing differences.

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

9.4 SUMMARY

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

The PBR Decision (at pages 120-121) stated that the inclusion of symmetric earnings sharing is beneficial to both FBC and its customers, and approved an earnings sharing mechanism where gains and losses are shared equally between FBC and customers. For 2019, FBC is proposing to distribute a $0.345 million pre-tax credit ($0.252 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2018 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth; and
- The true-up of the 2017 projected earnings sharing to actual.

Table 10-1: Summary of Earnings Sharing to be Returned in 2019[28] ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2018 Projected Sharing	$ (0.129)	Table 10-2, Line 48
2	2017 Actual Customer Growth Adjustment	0.006	Table 10-3, Line 18
3	2017 Projected vs. Actual Ending Balance True-Up	(0.129)	Table 10-4, Line 3
4			
5	2019 After-Tax Amount Returned to Customers	(0.252)	
6	2019 Pre-Tax Amount Returned to Customers	(0.345)	

Each of these items is discussed in the sections below.

10.1 *2018 PROJECTED SHARING*

As set out in FBC's letter dated November 7, 2014 in response to Order G-163-14 and as approved by Order G-107-15 for FBC's Annual Review for 2015 Rates, the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula-driven gross O&M and cumulative capital expenditures, as follows:

Formula-driven O&M less actual base O&M[29] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[30]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

As discussed in Sections 1.4.4 and 1.4.3.1, FBC is projecting 2018 formula-driven O&M savings at $1.000 million, and 2018 capital expenditures in excess of the formula by $11.394 million. The $11.394 million excess 2018 capital expenditures will exceed the dead band by $8.372

[28] Financing on the deferral account balances is included in the deferred charges schedule in Section 11, Schedule 12, Line 33.
[29] Excluding items that are forecast outside of the formula.
[30] Ibid.

million, therefore FBC has removed the $8.372 million amount above the dead band in the calculation of 2018 earnings sharing, as shown in Line 28 of Table 10-2 below.

Table 10-2: Calculation of 2018 Projected Earnings Sharing ($ millions)

Line No.	Description		Annual Capital Expenditures 2014	2015	2016	2017	2018	Reference
1	Approved Formula O&M	$ 54.776						G-38-18
2								
3	Actual/Projected Gross O&M	57.374						
4								
5	Less: O&M Tracked Outside of Formula							
6	Pension/OPEB (O&M Portion)	2.659						
7	Insurance Premiums	1.246						
8	Advanced Metering/Infrastructure Costs/Savings	(1.139)						
9	MRS Incremental Operating Expense	1.040						
10	Upper Bonnington Old Units Annual Inspection	(0.040)						
11	MSP Premium Reduction	(0.168)						
12	Total	3.598						Sum of Lines 6 - 11
13								
14	Actual/Projected Base O&M	53.776						Line 3 - Line 12
15								
16	O&M Subject to Sharing	$ (1.000)						Line 14 - Line1
17								
18								
19								
20	Cumulative Formula Capital Expenditures	$ 214.523	$ 42.193	$ 42.384	$ 42.874	$ 43.254	$ 43.818	G-139-14
21								
22	Cumulative Total Regular Capital Expenditures	269.050	49.061	49.043	49.512	62.592	58.842	Notes 1, 2
23								
24	Less: Capital Expenditures Tracked Outside of Formula							
25	Cumulative Pension and OPEB	21.492	6.396	4.253	3.674	3.539	3.630	
26								
27	Actual/Projected Base Capital Expenditures	247.558	42.665	44.791	45.838	59.053	55.212	Line 22 - Line 25
28	Deadband Adjustment	(20.131)	-	-	-	(11.759)	(8.372)	Adjustment to stay within deadband
29	Actual/Projected Base Capital Expenditures for ESM Calculation	227.427	42.665	44.791	45.838	47.294	46.840	Line 27 - Line 28
30								
31	Actual/Projected Cumulative Base Capital Expenditure Variance	12.904	0.472	2.408	2.964	4.040	3.022	Line 29 - Line 20
32								
33	Single Year Deadband % Variance (After Adjustment)		0.97%	5.16%	6.37%	8.63%	6.37%	Line 31 ÷ (Lines 20 + 25)
34	Two Year Cumulative Deadband % Variance (After Adjustment)			6.13%	11.53%	15.00%	15.00%	Line 33, sum of two years
35								
36	Equity Component of Rate Base	40.00%						G-139-14
37	Approved Return on Equity	9.15%						G-75-13/G-47-14
38	After Tax Capital Expenditures Subject to Sharing	0.472						Product of Lines 31, 36 & 37
39								
40	Tax Rate	27.00%						G-139-14
41								
42	Before Tax Capital Expenditures Subject to Sharing	0.647						Line 38 ÷ (1 - Line 40)
43								
44	Total Before Tax Sharing Account	(0.353)						Line 16 + Line 42
45	Sharing Percentage	50.00%						G-139-14
46								
47	2018 Projected Earnings Sharing (Pre-Tax)	$ (0.177)						Line 44 x Line 45
48	2018 Projected Earnings Sharing (After-Tax)	$ (0.129)						Line 47 x (1- Line 40)
49								
50	Note 1: 2014 through 2016 are actual results from BCUC Annual Reports. 2014 Regular Capital Expenditures restated to correct treatment of capitalized inventory and transfer of land purchased for the Kootenay Operations Centre to CPCN-related capital upon approval of the project.							
51	Note 2: Pursuant to Order G-9-18, the costs of FBC's Electric Vehicle DCFC stations are excluded from rate base until the Commission directs otherwise. FBC has removed expenditures of $0.316 million from 2017 formula capital expenditures as reported in the BCUC Annual Report for 2017.							

10.2 *ACTUAL CUSTOMER GROWTH ADJUSTMENT*

Order G-15-15 stated the following in relation to formula capital expenditures:

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return

resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

FBC has calculated the resulting adjustment of $0.008 million debit ($0.006 million debit after tax) for 2017 as shown in Table 10-3 below based on its actual customer additions.

Table 10-3: Calculation of Earnings Sharing Adjustment for Actual Customer Growth ($ millions)

Line No.	Description		Reference
1	Average Customers 2017	134,246	
2	Average Customers 2016	132,480	
3	Growth in Average Customers	1,766	Line 1 - Line 2
4	Average Customer Growth	1.333%	Line 3 ÷ Line 2
5		50%	G-139-14
6	Average Customer Growth to be recast in Formula	0.667%	
7	2017 Net Inflation Factor	0.390%	G-11-17; Oct. 5, 2016 Evidentiary Update, Section 11, Schedule 3, Line 9, Column 6
8	2016 Reforecast Formulaic Capital	$ 43.035	Annual Review for 2018 Rates, Table 10-3, Line 9
9	2017 Reforecast Formulaic Capital	$ 43.491	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2017 Year Formulaic Capital	$ 43.254	G-11-17; Oct. 5, 2016 Evidentiary Update, Section 11, Schedule 4, Line 14, Column 4
11			
12	Increase in Capital Requirements from Actual Growth	$ 0.237	Line 9 - Line 10
13	Mid-Year	$ 0.118	Line 12 x 0.5
14			
15	Equity Cost Component	3.66%	G-11-17; Oct 5, 2016 Evidentiary Update, Section 11, Schedule 26, Line 3, Column 6
16	Debt Cost Component	3.13%	G-11-17; Oct 5, 2016 Evidentiary Update, Section 11, Schedule 26, Lines 1+2, Column 6
17	Earned Return on Incremental Capital Requirements (Pre-Tax)	$ 0.008	Line 13 x (line 15 + Line 16)
18	Earned Return on Incremental Capital Requirements (After-Tax)	$ 0.006	Line 17 x 0.73

10.3 *TRUE-UP FOR 2017 ACTUAL EARNINGS SHARING*

In FBC's 2017 Annual Report to the Commission, FBC calculated the final 2017 earnings sharing based on the final 2017 results. The final balance of earnings sharing for 2017 was $0.744 million (after-tax), which was $0.129 million higher than the $0.615 million projected for 2017 as shown in Table 10-4 below. As a result, FBC is increasing its 2018 earnings sharing by the after-tax amount of $0.129 million as shown in Table 10-1 above.

Table 10-4: Calculation of 2017 Actual Earnings Sharing True-Up ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2017 Actual Earnings Sharing Account Ending Balance	$ (0.744)	2017 Annual Report to BCUC
2	2017 Projected Earnings Sharing Account Ending Balance	(0.615)	G-38-18 Compliance Filing, Section 11, Schedule 12, Line 24, Column 2
3	2017 Earnings Sharing Account True-Up	$ (0.129)	

10.4 *SUMMARY OF EARNINGS SHARING*

After calculating the 2018 projected earnings sharing and including the adjustments described above, FBC proposes to distribute $0.345 million to customers in 2019 as a reduction in 2019 revenue requirements through amortization of the projected 2019 opening after-tax balance of $0.252 million in the Earnings Sharing deferral account.

As part of future rate filings, the earnings sharing for 2018 will be subject to similar true-ups as described above, which will account for the actual O&M and capital expenditure amounts for 2018, as well as impacts, if any, associated with non-performance of Service Quality Metrics, based on final 2018 results.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000,000s)

Schedule 1

Line No.	Particulars	2019 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	(14.194)		
3	Change in Other Revenue	(0.852)	(15.046)	
4				
5	**POWER SUPPLY**			
6	Power Purchases (net of customer growth and volume)	11.994		
7	Wheeling	0.064		
8	Water Fees	0.257	12.315	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	0.608		
12	Capitalized Overhead Change	(0.091)	0.517	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions	1.748	1.748	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.182)		
19	Deferrals	(5.737)	(5.920)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.261		
23	Financing Ratio Changes	0.010		
24	Rate Base Growth	1.354	1.625	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes Changes	0.029		
28	Other Income Taxes Changes	(1.922)	(1.893)	
29				
30	2018 Revenue Deficiency		0.896	
31	2019 Revenue Surplus		5.759	
32				
33	Revenue Deficiency (Surplus)		$ -	Schedule 16, Line 6, Column 4
34				
35	Revenue at Existing Rates		370.534	Schedule 16, Line 5, Column 3
36	Rate Change		0.00%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 2

Line No.	Particulars	2018 Approved	2019 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning [1]	$ 1,966,584	$ 2,040,679	$ 74,095	Schedule 6.1, Line 14, Column 3
2	Opening Balance Adjustment	8,744	8,372	(372)	Schedule 6.1, Line 14, Column 4
3	Net Additions	73,890	66,972	(6,918)	Schedule 6.1, Line 14, Columns 5+6+7
4	Plant in Service, Ending	2,049,218	2,116,023	66,805	
5					
6	Accumulated Depreciation Beginning	$ (591,854)	$ (630,983)	$ (39,129)	Schedule 7.1, Line 14, Column 5
7	Opening Balance Adjustment	2,147	-	(2,147)	Schedule 7.1, Line 14, Column 6
8	Net Additions	(43,386)	(42,067)	1,319	Schedule 7.1, Line 14, Columns 7+8+9+10
9	Accumulated Depreciation Ending	(633,093)	(673,050)	(39,957)	
10					
11	CIAC, Beginning	$ (187,217)	$ (195,767)	$ (8,550)	Schedule 9, Line 1, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(6,120)	(8,876)	(2,756)	Schedule 9, Line 1, Column 4
14	CIAC, Ending	(193,337)	(204,643)	(11,306)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 68,323	$ 71,910	$ 3,587	Schedule 9, Line 3, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	3,913	4,095	182	Schedule 9, Line 3, Column 4
19	Accumulated Amortization Ending - CIAC	72,236	76,006	3,769	
20					
21	Net Plant in Service, Mid-Year	$ 1,280,876	$ 1,304,274	$ 23,398	
22					
23	Adjustment for timing of Capital additions	$ 12,644	$ 7,388	$ (5,256)	
24	Capital Work in Progress, No AFUDC	8,921	8,921	-	
25	Unamortized Deferred Charges	11,624	13,458	1,835	Schedule 11, Line 17, Column 8
26	Working Capital	1,660	2,105	445	Schedule 13, Line 15, Column 3
27	Utility Plant Acquistion Adjustment	5,493	5,307	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,321,217	$ 1,341,452	$ 20,235	
30					

31 Note 1: Pursuant to Order G-9-18, the costs of FBC's Electric Vehicle DCFC stations are excluded from rate base until the Commission directs otherwise.
FBC has excluded 2017 capital expenditures of $0.316 million and CIAC of $0.177 million from rate base.

- -

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 3

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%	2.635%	
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%	2.505%	
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%	1.475%	
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%	102.376%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 4

Line No.	Particulars	CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base	$ 41,875			
3	**2014**				
4	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
5	Formula Capex	42,193			
6	**2015**				
7	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
8	Formula Capex	42,384			
9	**2016**				
10	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
11	Formula Capex	42,874			
12	**2017**				
13	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
14	Formula Capex	43,254			
15	**2018**				
16	Net Inflation Factor	101.304%			Schedule 3, Line 12, Column 7
17	Formula Capex	43,818			
18	**2019**				
19	Net Inflation Factor	102.376%			Schedule 3, Line 12, Column 8
20	Formula Capex	44,859		$ 44,859	
21					
22					
23	**Capital Tracked Outside of Formula**				
24	Pension & OPEB (Capital Portion)		$ 3,612		
25	AMI Sustainment Capital		937		
26	Mandatory Reliability Standards Incremental Capital		2,780		
27	Employer Health Tax		624		
28	MSP Premium Reduction		(182)		
29	Corra Linn Spillway Gate Replacement		12,750		
30	Upper Bonnington Old Units Refurbishment		7,449		
31	Total		$ 27,970	$ 27,970	
32					
33	**Total Capital Expenditures before CIAC**			$ 72,829	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 5

Line No.	Particulars	2019	Cross Reference
	(1)	(2)	(3)
1	**CAPITAL EXPENDITURES**		
2			
3	Formula Capital Expenditures	$ 44,859	Schedule 4, Line 20, Column 4
4	Forecast Capital Expenditures	7,771	Schedule 4, Lines 24 to 28, Column 3
5	Total Regular Capital Expenditures	$ 52,630	
6			
7	**CPCN and Special Projects**		
8	Corra Linn Spillway Gate Replacement	12,750	Schedule 4, Line 29, Column 3
9	Upper Bonnington Old Units Refurbishment	7,449	Schedule 4, Line 30, Column 3
10	Total CPCN and Special Projects	$ 20,199	
11			
12	**Total Capital Expenditures**	$ 72,829	
13			
14			
15	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
16			
17	Regular Capital Expenditures	$ 52,630	
18	Add - Capitalized Overheads	8,880	Schedule 20, Line 36, Column 4
19	Add - Direct Overheads	5,000	
20	Add - AFUDC	692	
21	Less: Removal costs	(2,633)	Schedule 7.1, Line 14, Column 9 - Schedule 5, Row 29
22	Gross Capital Expenditures	$ 64,569	
23	Change in Work in Progress	-	
24	**Total Additions to Plant**	$ 64,569	
25			
26			
27	**CPCN and Special Projects**	$ 20,199	
28	Add - AFUDC	2,082	
29	Less: Removal costs	(3,084)	
30	Gross Capital Expenditures	19,197	
31	Change in Work in Progress	(4,422)	
32	**Total Additions to Plant**	$ 14,775	
33			
34	**Grand Total Additions to Plant**	$ 79,344	Schedule 6.1, Line 14, Columns 5 + 6

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/18	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/19	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	16,763	47	32	359	(15)	17,186	
4	332	Reservoirs, Dams & Waterways	34,886	113	202	875	(50)	36,027	
5	333	Water Wheels, Turbines and Gen.	101,161	6	5,967	45	(553)	106,626	
6	334	Accessory Equipment	44,596	52	1,383	404	(456)	45,979	
7	335	Other Power Plant Equipment	46,006	73	-	561	(19)	46,620	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 245,661	$ 291	$ 7,584	$ 2,244	$ (1,093)	$ 254,687	
10		**Transmission Plant**							
11	350	Land Rights-R/W	$ 9,753	$ 27	$ -	$ 206	$ -	$ 9,986	
12	350.1	Land Rights-Clearing	8,983	27	-	206	-	9,216	
13	353	Station Equipment	238,436	1,793	501	13,826	(227)	254,328	
14	355	Poles Towers & Fixtures	112,563	455	-	3,508	(301)	116,225	
15	356	Conductors and Devices	107,992	375	-	2,889	(332)	110,923	
16	359	Roads and Trails	1,121	-	-	-	-	1,121	
17			$ 478,848	$ 2,676	$ 501	$ 20,635	$ (860)	$ 501,800	
18		**Distribution Plant**						-	
19	360	Land Rights-R/W	$ 4,256	$ -	$ -	$ -	$ -	$ 4,256	
20	360.1	Land Rights-Clearing	10,847	-	-	-	-	10,847	
21	362	Station Equipment	263,643	-	6,690	-	(423)	269,910	
22	364	Poles Towers & Fixtures	261,558	2,572	-	19,840	(484)	283,487	
23	365	Conductors and Devices	306,338	768	-	5,922	(786)	312,243	
24	368	Line Transformers	138,748	384	-	2,961	(1,461)	140,633	
25	369	Services	9,521	-	-	-	-	9,521	
26	370	Meters	(238)	-	-	-	(20)	(258)	
27	370.1	AMI Meters	40,988	115	-	888	-	41,992	
28	371	Installation on Customers' Premises	938	-	-	-	-	938	
29	373	Street Lighting and Signal System	11,971	-	-	-	(57)	11,913	
30			$ 1,048,570	$ 3,839	$ 6,690	$ 29,611	$ (3,231)	$ 1,085,480	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/18	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/19	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**General Plant**							
2	389	Land	$ 11,003	$ -	$ -	$ -	$ -	$ 11,003	
3	390	Structures - Frame & Iron	12	-	-	-	-	12	
4	390.1	Structures - Masonry	60,817	98	-	753	-	61,667	
5	391	Office Furniture & Equipment	6,029	21	-	165	(530)	5,686	
6	391.1	Computer Equipment	103,414	1,039	-	8,017	(3,943)	108,527	
7	391.2	AMI Software	9,597	7	-	50	-	9,654	
8	392	Transportation Equipment	29,118	268	-	2,066	(1,749)	29,703	
9	394	Tools and Work Equipment	15,422	100	-	768	(405)	15,885	
10	397	Communication Structures & Equipment	27,218	33	-	257	(562)	26,946	
11	397.1	AMI Communications Structure & Equipment	4,970	-	-	3	-	4,972	
12			$ 267,600	$ 1,566	$ -	$ 12,078	$ (7,188)	$ 274,057	
13									
14		**Total Plant in Service**	$ 2,040,679	$ 8,372	$ 14,775	$ 64,569	$ (12,372)	$ 2,116,023	
15									
16		Cross Reference			Schedule 5 Line 32 Column 2	Schedule 5 Line 24 Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/18	Opening Bal. Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/19	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	2.60%	$ (800)	$ -	$ 25	$ -	$ -	$ -	$ (775)	
3	331	Structures and Improvements	16,841	1.29%	5,007	-	217	(15)	(44)	-	5,166	
4	332	Reservoirs, Dams & Waterways	35,202	1.78%	6,972	-	627	(50)	(2,808)	-	4,741	
5	333	Water Wheels, Turbines and Gen.	107,134	1.79%	17,890	-	1,918	(553)	(150)	-	19,104	
6	334	Accessory Equipment	46,031	2.28%	12,148	-	1,050	(456)	(81)	-	12,660	
7	335	Other Power Plant Equipment	46,079	2.05%	15,995	-	945	(19)	(25)	-	16,895	
8	336	Roads, Railroads and Bridges	1,287	1.47%	352	-	19	-	-	-	371	
9			$ 253,536		$ 57,564	$ -	$ 4,800	$ (1,093)	$ (3,109)	$ -	$ 58,162	
10		**Transmission Plant**										
11	350	Land Rights-R/W	$ 9,780	0.00%	$ (183)	$ -	$ -	$ -	$ -	$ -	$ (183)	
12	350.1	Land Rights-Clearing	9,010	1.23%	2,255	-	111	-	-	-	2,365	
13	353	Station Equipment	240,730	2.45%	78,998	-	5,898	(227)	(965)	-	83,703	
14	355	Poles Towers & Fixtures	113,018	2.53%	29,144	-	2,859	(301)	(219)	-	31,484	
15	356	Conductors and Devices	108,366	2.52%	22,995	-	2,731	(332)	(180)	-	25,214	
16	359	Roads and Trails	1,121	2.88%	338	-	32	-	-	-	370	
17			$ 482,025		$ 133,546	$ -	$ 11,631	$ (860)	$ (1,365)	$ -	$ 142,953	
18		**Distribution Plant**										
19	360	Land Rights-R/W	$ 4,256	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	360.1	Land Rights-Clearing	10,847	1.23%	2,348	-	133	-	-	-	2,482	
21	362	Station Equipment	270,333	2.57%	71,880	-	6,948	(423)	-	-	78,405	
22	364	Poles Towers & Fixtures	264,131	2.67%	63,655	-	7,052	(484)	(760)	-	69,464	
23	365	Conductors and Devices	307,106	2.89%	99,346	-	8,875	(786)	(227)	-	107,208	
24	368	Line Transformers	139,132	2.74%	33,917	-	3,812	(1,461)	(113)	-	36,155	
25	369	Services	9,521	0.50%	6,743	-	48	-	-	-	6,791	
26	370	Meters	(238)	6.68%	2,696	-	(16)	(20)	-	-	2,659	
27	370.1	AMI Meters	41,103	5.00%	2,359	-	2,055	-	(34)	-	4,380	
28	371	Installation on Customers' Premises	938	0.00%	938	-	-	-	-	-	938	
29	373	Street Lighting and Signal System	11,971	4.65%	4,170	-	557	(57)	-	-	4,670	
30			$ 1,059,100		$ 288,052	$ -	$ 29,464	$ (3,231)	$ (1,134)	$ -	$ 313,151	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/18	Opening Bal. Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/19	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**General Plant**										
2	389	Land	$ 11,003	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
3	390	Structures - Frame & Iron	12	0.56%	-	-	-	-	-	-	-	
4	390.1	Structures - Masonry	60,915	2.77%	16,734	-	1,687	-	(10)	-	18,411	
5	391	Office Furniture & Equipment	6,051	1.68%	4,813	-	102	(530)	(2)	-	4,383	
6	391.1	Computer Equipment	104,453	7.21%	85,472	-	7,531	(3,943)	(57)	-	89,004	
7	391.2	AMI Software	9,604	10.00%	3,393	-	960	-	-	-	4,353	
8	392	Transportation Equipment	29,386	6.01%	8,787	-	1,766	(1,749)	(27)	-	8,777	
9	394	Tools and Work Equipment	15,522	2.49%	10,301	-	386	(405)	(10)	-	10,273	
10	397	Communication Structures & Equipment	27,252	5.49%	21,220	-	1,496	(562)	(3)	-	22,151	
11	397.2	AMI Communications Structure & Equipment	4,970	6.67%	1,068	-	331	-	-	-	1,399	
12			$ 269,166		$ 151,820	$ -	$ 14,261	$ (7,188)	$ (109)	$ -	$ 158,784	
13												
14	108	Total Accumulated Depreciation	$ 2,063,826		$ 630,983	$ -	$ 60,156	$ (12,372)	$ (5,717)	$ -	$ 673,050	
15												
16		Cross Reference	Schedule 6.1									
17			Line 14									
18			Columns 3+4+5									

SCHEDULE NOT APPLICABLE

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 9

Line No.	Particulars	12/31/18	Adjustment	Additions	Retirements	12/31/19	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**	$ 195,767	$ -	$ 8,876	$ -	$ 204,643	
2							
3	**Amortization**	(71,910)	-	(4,095)	-	(76,006)	
4							
5	**Net CIAC**	$ 123,857	$ -	$ 4,781	$ -	$ 128,637	

SCHEDULE NOT APPLICABLE

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 11

Line No.	Particulars	12/31/18	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/19	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1. Forecasting Variance Accounts								
2									
3	2. Rate Smoothing Accounts								
4									
5	3. Benefits Matching Accounts								
6	Demand Side Management	$ 24,483	$ -	$ 8,100	$ (2,187)	$ (4,069)	$ 26,326	$ 25,405	
7	Deferred Debt Issue Costs	3,543	-	-	(29)	(162)	3,352	3,448	
8	Preliminary and Investigative Charges[1]	191	-	300	-	-	491	341	Note 1
9	Accounting Treatment of non-AMI Meters	1,082	-	-	-	(1,082)	-	541	
10		$ 29,298	$ -	$ 8,400	$ (2,216)	$ (5,313)	$ 30,170	$ 29,734	
11	4. Retroactive Expense Accounts								
12									
13	5. Other Accounts								
14	Pension and OPEB Liability	(16,805)	-	1,059	-	-	(15,746)	(16,276)	
15		$ (16,805)	$ -	$ 1,059	$ -	$ -	$ (15,746)	$ (16,276)	
16									
17	**Total Rate Base Deferral Accounts**	$ 12,493	$ -	$ 9,459	$ (2,216)	$ (5,313)	$ 14,424	$ 13,458	
18									

19 Note 1: Gross additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress.
Additions of $0.400 million - transfers of $0.100 million = $0.300 million.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 12

Line No.	Particulars	12/31/18	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/19	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	1. Forecasting Variance Accounts								
4	Revenue and Power Supply[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Flow-Through Accounts	(12,788)	-	-	-	12,788	-	(6,394)	
6	Pension & Other Post Retirement Benefits (OPEB) Variance	(695)	-	-	-	266	(429)	(562)	
7		$ (13,483)	$ -	$ -	$ -	$ 13,054	$ (429)	$ (6,956)	
8	2. Rate Smoothing Accounts								
9	2018 Revenue Deficiency	$ 654	$ (654)	$ -	$ -	$ -	$ -	$ -	
10									
11	3. Benefits Matching Accounts								
12	2014-2019 Performance Based Ratemaking Application	246	-	-	-	(246)	-	123	
13	Annual Reviews for 2015-2019 Rates	79	-	-	-	(79)	-	40	
14	Self-Generation Policy Application, Stage II	35	-	-	-	(35)	-	18	
15	Net Metering Program Tariff Update	38	-	-	-	(38)	-	19	
16	BCUC Residential Inclining Block Rate Report	5	-	-	-	(5)	-	2	
17	2017 Demand Side Management Expenditure Schedule Application	(1)	-	-	-	1	-	(0)	
18	2018 Demand Side Management Expenditure Schedule Application	54	-	-	-	(54)	-	27	
19	Community Solar Pilot Project	(27)	-	-	-	27	-	(14)	
20	Tariff Applications	(74)	-	-	-	74	-	(37)	
21	Electric Vehicle Charging Stations Rate Design and Tariff Application	44	-	-	-	-	44	44	
22		$ 399	$ -	$ -	$ -	$ (355)	$ 44	$ 221	
23	4. Retroactive Expense Accounts								
24									
25	5. Other Accounts								
26	2014-2019 Earnings Sharing Account	(252)	-	-	-	252	-	(126)	
27	Castlegar Office Disposition	(439)	-	-	-	439	-	(220)	
28	BC Hydro Waneta 2017 Transactions	91	-	-	-	(91)	-	45	
29		$ (601)	$ -	$ -	$ -	$ 601	$ -	$ (300)	
30									
31	**Total Deferral Accounts at Short Term Interest**	$ (13,031)	$ (654)	$ -	$ -	$ 13,300	$ (385)	$ (7,035)	
32									
33	Financing Costs at STI	$ (333)	$ -	$ (297)		$ 333	$ (297)	$ (315)	
34									

35 Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 12.1

Line No.	Particulars	12/31/18	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/19	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	1. Forecasting Variance Accounts								
4									
5	2. Rate Smoothing Accounts								
6	2018 - 2019 Revenue Surplus	$ -	$ 654	$ (5,759)	$ 1,555	$ -	$ (3,550)	$ (1,448)	
7									
8	3. Benefits Matching Accounts								
9	CPCN Projects Preliminary Engineering[1]	$ 255	$ -	$ (255)	$ -	$ -	$ -	$ 127	
10	2016 Long Term Electric Resource Plan	441	-	-	-	(110)	331	386	
11	2017 Rate Design Application	1,037	-	100	(27)	(222)	888	962	
12	Transmission Customer Rate Design	-	-	-	-	-	-	-	
13	2020 Revenue Requirements	164	-	975	(263)	-	876	520	
14	2019 - 2022 Multi-Year DSM Expenditure Schedule	158	-	60	(16)	(50)	151	155	
15	2018 Joint Pole Use Audit	117	-	-	-	(29)	88	102	
16		$ 2,172	$ -	$ 880	$ (306)	$ (412)	$ 2,334	$ 2,253	
17	4. Retroactive Expense Accounts								
18									
19	5. Other Accounts								
20	US GAAP Pension and OPEB Transitional Obligation	$ 1,901	$ -	$ (512)	$ -	$ -	$ 1,389	$ 1,645	
21	Advanced Metering Infrastructure Radio-Off Shortfall	88	-	-	-	-	88	88	
22		$ 1,989	$ -	$ (512)	$ -	$ -	$ 1,477	$ 1,733	
23									
24									
25	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 4,161	$ 654	$ (5,391)	$ 1,248	$ (412)	$ 261	$ 2,538	
26									
27	Financing Costs at WACD	$ 155	$ -	$ 133		$ (155)	$ 133	$ 144	
28									
29	**Deferral Accounts Financed at WACC**								
30									
31	3. Benefit Matching Accounts								
32	On Bill Financing (OBF) Participant Loans	$ 8	$ -	$ (1)	$ -	$ -	$ 7	$ 7	
33									
34	Financing Costs at AFUDC	$ 1	$ -	$ -		$ (1)	$ -	$ 0	
35									
36	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
37									
38	**Total Non Rate Base Deferral Accounts (including financing)**	$ (8,989)	$ -	$ (5,556)	$ 1,248	$ 13,065	$ (231)	$ (4,610)	

39 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 13

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 4,930	$ 5,075	$ 145	Schedule 14, Line 42, Column 5
3					
4	Add: Funds Unavailable				
5	Customer Loans	430	470	40	
6	Employee Loans	310	350	40	
7	Uncollectible Accounts	1,700	2,000	300	
8	Inventory (average monthly investment)	680	650	(30)	
9					
10	Less: Funds Available				
11	Average Customer Deposits	(5,150)	(5,470)	(320)	
12	Average Provincial Sales Tax	(690)	(600)	90	
13	Average Goods and Services Tax	(550)	(370)	180	
14					
15	Total	$ 1,660	$ 2,105	$ 445	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 14

Line No.	Particulars	2019 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 187,887	50.5	$ 9,488		
4	Commercial Tariff Revenue	94,508	49.4	4,669		
5	Wholesale Tariff Revenue	49,519	33.2	1,644		
6	Industrial Tariff Revenue	32,414	33.2	1,076		
7	Lighting Tariff Revenue	2,661	50.1	133		
8	Irrigation Tariff Revenue	3,544	45.3	161		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	4,878	27.4	134		
12	Contract Revenue	1,766	43.6	77		
13	Transmission Revenue	1,230	15.2	19		
14	Interest Income	16	15.2	0		
15	Late Payment Charges	861	90.0	77		
16	Other Utility Income	517	44.7	23		
17						
18	Total	$ 379,802		$ 17,501	46.1	
19						
20	**EXPENSES**					
21	Power Purchases	$ 145,065	41.7	6,049		
22	Wheeling	5,235	40.2	210		
23	Water Fees	10,465	(1.0)	(10)		
24	Operating Labour					
25	Salaries and Wages	17,136	5.3	91		
26	Employee Benefits	10,104	13.2	133		
27	Contracted Labour	12,690	50.6	642		
28	Rental of T&D Facilities	3,345	48.6	163		
29	Office Lease	569	(15.2)	(9)		
30	Materials	5,192	45.6	237		
31	Insurance	1,283	(182.5)	(234)		
32	Interest	40,943	85.2	3,488		
33	Property Taxes	16,713	1.4	23		
34	Income Tax	7,711	15.2	117		
35						
36	Total	$ 276,452		$ 10,901	(39.4)	
37						
38	Net Lag (Lead) Days				6.7	
39						
40	Total Expenses				$ 276,452	
41						
42	Cash Working Capital				$ 5,075	

SCHEDULE NOT APPLICABLE

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 16

Line No.	Particulars	2018 Approved	2019 Forecast at Existing Rates	2019 Forecast Revised Revenue	2019 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,213	3,319		3,319	106	Schedule 17, Line 9, Column 3
3							
4	**REVENUE**						
5	Sales	$ 356,340	$ 370,534	$ -	$ 370,534	$ 14,194	Schedule 17, Line 19, Column 3
6	Deficiency (Surplus)	-	-	-	-	-	
7	Total	356,340	370,534	-	370,534	14,194	Schedule 18, Line 8, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	148,450	160,765	-	160,765	12,315	Schedule 19, Line 31, Column 3
11	O&M Expense (net)	49,802	50,319	-	50,319	517	Schedule 20, Line 37, Column 4
12	Depreciation & Amortization	52,667	48,495	-	48,495	(4,172)	Schedule 21, Line 11, Column 3
13	Property Taxes	16,684	16,713	-	16,713	29	Schedule 22, Line 7, Column 3
14	Other Revenue	(8,416)	(9,268)	-	(9,268)	(852)	Schedule 23, Line 9, Column 3
15	2018 - 2019 Revenue Surplus	(896)	5,759	-	5,759	6,655	
16	Utility Income Before Income Taxes	98,048	97,751	-	97,751	(297)	
17							
18	Income Taxes	9,633	7,711	-	7,711	(1,922)	Schedule 24, Line 13, Column 3
19							
20	**EARNED RETURN**	$ 88,416	$ 90,041	$ -	$ 90,041	$ 1,625	Schedule 26, Line 5, Column 7
21							
22	**UTILITY RATE BASE**	$ 1,321,217	$ 1,341,452		$ 1,341,452	$ 20,235	Schedule 2, Line 29, Column 3
23	**RATE OF RETURN ON UTILITY RATE BASE**	6.69%	6.71%		6.71%	0.02%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 17

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,280	1,349	69	
3	Commercial	912	935	23	
4	Wholesale	586	594	8	
5	Industrial	379	385	6	
6	Lighting	15	13	(2)	
7	Irrigation	41	42	1	
8					
9	Total	3,213	3,319	106	
10					
11	**REVENUE AT EXISTING RATES**				
12	Residential	$ 178,976	$ 187,887	$ 8,911	
13	Commercial	90,669	94,508	3,839	
14	Wholesale	48,565	49,519	954	
15	Industrial	31,712	32,414	702	
16	Lighting	2,903	2,661	(241)	
17	Irrigation	3,515	3,544	29	
18					
19	Total	$ 356,340	$ 370,534	$ 14,194	

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 18

Line No.	Particulars	2018 Approved Revenue	2019 Forecast Revenue at Existing Rates	2019 Forecast Effective Increase	2019 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 178,976	$ 187,887	$ -	$ 187,887	120,405	1,349	
2	Commercial	90,669	94,508	-	94,508	16,405	935	
3	Wholesale	48,565	49,519	-	49,519	6	594	
4	Industrial	31,712	32,414	-	32,414	51	385	
5	Lighting	2,903	2,661	-	2,661	1,511	13	
6	Irrigation	3,515	3,544	-	3,544	1,080	42	
7								
8	Total	$ 356,340	$ 370,534	$ -	$ 370,534	139,459	3,319	
9								
10	**Effective Increase**				0.00%			

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 19

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,485	3,602	116	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 39,632	$ 41,865	$ 2,233	
6	BC Hydro PPA	44,906	52,174	7,267	
7	Waneta Expansion	37,437	40,221	2,784	
8	Market and Contracted Producers	10,951	10,637	(314)	
9	Independent Power Producers	80	76	(4)	
10	Self-Generators	66	93	27	
11	Balancing Pool	-	-	-	
12					
13	Total	$ 133,071	$ 145,065	$ 11,994	
14					
15	**WHEELING**				
16	**Wheeling Nomination (MW months)**				
17	Okanagan Point of Interconnection	2,490	2,400	(90)	
18	Creston	444	471	27	
19					
20	**Wheeling Expense**				
21	Okanagan Point of Interconnect	$ 4,590	$ 4,514	$ (75)	
22	Creston	534	577	44	
23	Other	48	144	96	
24	Total	$ 5,171	$ 5,235	$ 64	
25					
26	**WATER FEES**				
27	Plant Entitlement Use in previous year (GWh)	1,568	1,574	7	
28					
29	Water Fees	$ 10,208	$ 10,465	$ 257	
30					
31	Total	$ 148,450	$ 160,765	$ 12,315	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 60,159			
3	Less: O&M tracked outside of Formula	(7,810)			
4	O&M Subject to Formula	52,349			
5	**2014**				
6	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
7	Formula O&M	52,746			
8	**2015**				
9	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
10	Formula O&M	52,984			
11	**2016**				
12	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
13	Formula O&M	53,596			
14	**2017**				
15	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
16	Formula O&M	54,071			
17	**2018**				
18	Net Inflation Factor	101.304%			Schedule 3, Line 12, Column 7
19	Formula O&M	54,776			
20	**2019**				
21	Net Inflation Factor	102.376%			Schedule 3, Line 12, Column 8
22	Formula O&M	56,077		$ 56,077	
23					
24	**O&M Tracked Outside of Formula**				
25	Pension & OPEB (O&M Portion)		$ 1,692		
26	Insurance Premiums		1,283		
27	Advanced Metering Infrastructure Costs/Savings		(1,161)		
28	Mandatory Reliability Standards Incremental O&M		940		
29	Upper Bonnington Unit 1 Annual Inspection		(40)		
30	Employer Health Tax		576		
31	MSP Premium Reduction		(168)		
32	Total		$ 3,122	3,122	
33					
34	**Total Gross O&M**			$ 59,199	
35					
36	Capitalized Overhead - 15% of Total Gross O&M			(8,880)	
37	**Net O&M Expense**			$ 50,319	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 58,408	$ 60,156	$ 1,748	Schedule 7.1, Line 14, Column 7
3					
4	**Amortization**				
5	Rate Base deferrals	$ 5,131	$ 5,313	$ 182	Schedule 11, Line 17, Column 6
6	Non-Rate Base deferrals	(7,146)	(13,065)	(5,919)	Schedule 12.1, Line 38, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(3,913)	(4,095)	(182)	Schedule 9, Line 3, Column 4
9		(5,741)	(11,661)	(5,920)	
10					
11	Total	$ 52,667	$ 48,495	$ (4,172)	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 22

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,080	$ 3,082	$ 2	
2	Transmission and Distribution	6,672	6,705	33	
3	Substation Equipment	3,731	3,741	10	
4	Land and Buildings	1,192	1,019	(173)	
5	1% In-Lieu of Municipal Taxes	2,009	2,166	157	
6					
7	Total	$ 16,684	$ 16,713	$ 29	

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 4,736	$ 4,878	$ 142	
2	Contract Revenue	1,769	1,766	(3)	
3	Transmission Access Revenue	1,170	1,230	60	
4	Interest Income	16	16	-	
5	Late Payment Charges	-	861	861	
6	Connection Charge	368	376	7	
7	Other Recoveries	356	142	(215)	
8					
9	Total	$ 8,416	$ 9,268	$ 852	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 24

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 88,416	$ 90,041	$ 1,625	Schedule 16, Line 20, Column 5
2	Deduct: Interest on Debt	(40,059)	(40,943)	(884)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(22,311)	(28,249)	(5,937)	Schedule 24, Line 29, Column 3
4	Accounting Income After Tax	$ 26,045	$ 20,849	$ (5,196)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 35,678	$ 28,560	$ (7,118)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 9,633	$ 7,711	$ (1,922)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 9,633	$ 7,711	$ (1,922)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 58,408	$ 60,156	$ 1,748	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(2,015)	(7,752)	(5,737)	Schedule 21, Lines 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension & OPEB Expense	6,289	5,304	(985)	
22					
23	Deductions:				
24	Capital Cost Allowance	(66,505)	(67,520)	(1,015)	Schedule 25, Line 19, Column 6
25	CIAC Amortization	(3,913)	(4,095)	(182)	Schedule 21, Line 8, Column 3
26	Pension & OPEB Contributions	(5,594)	(5,537)	57	
27	Overheads Capitalized Expensed for Tax Purposes	(8,789)	(8,880)	(91)	Schedule 20, Line 36, Column 4
28	All Other	(379)	(111)	268	
29	Total	$ (22,311)	$ (28,249)	$ (5,937)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 25

Line No.	Class	CCA Rate	31/12/2018 UCC Balance	Adjustments	2019 Additions	2019 CCA	31/12/2019 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 181,529	$ -	$ -	$ (7,261)	$ 174,268
2	1(b)	6%	32,218	-	616	(1,952)	30,883
3	2	6%	14,606	-	-	(876)	13,729
4	3	5%	930	-	-	(47)	884
5	6	10%	4	-	-	(0)	3
6	8	20%	4,616	-	753	(999)	4,371
7	9	25%	-	-	-	-	-
8	10	30%	4,833	-	1,712	(1,707)	4,838
9	12	100%	-	-	-	-	-
10	14.1	5%	9,259		-	(463)	8,796
11	14.1	7%	819	-	338	(69)	1,088
12	17	8%	113,760	-	21,639	(9,966)	125,432
13	42	12%	3,901	-	205	(480)	3,626
14	45	45%	6	-	-	(2)	3
15	46	30%	7,165	-	-	(2,150)	5,016
16	47	8%	442,287	-	36,412	(36,839)	441,860
17	50	55%	4,922	-	7,278	(4,709)	7,491
18							
19	Total		$ 820,855	$ -	$ 68,953	$ (67,520)	$ 822,288

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 26

Line No.	Particulars	2018 Approved Earned Return	2019 Amount	2019 Ratio	2019 Average Embedded Cost	2019 Cost Component	2019 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 38,068	$ 735,000	54.79%	5.18%	2.84%	$ 38,068	$ -	Schedule 27, Line 9, Column 6
2	Short Term Debt	1,992	69,871	5.21%	4.12%	0.21%	2,876	884	
3	Common Equity	48,357	536,581	40.00%	9.15%	3.66%	49,097	741	
4									
5	Total	$ 88,416	$ 1,341,452	100.00%		6.71%	$ 90,041	$ 1,625	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 27

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Series G	August 28, 1993	August 28, 2023	$ 25,000	8.800%	$ 2,200	
2	Series I	December 1, 1997	December 1, 2021	25,000	7.810%	1,953	
3	Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
4	Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
5	MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
6	MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
7	MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
8	MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
9	Total			$ 735,000		$ 38,068	
10							
11	Average Embedded Cost				5.18%		

12. ACCOUNTING MATTERS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FBC discusses "Exogenous Factors" under its PBR Plan (identifying two new exogenous factors that affect 2018 and 2019 and updating one previously approved), emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC requests approval of three new deferral accounts related to regulatory proceedings. FBC also requests approval of an amendment to one approved deferral account, requests the disposition of three existing deferral accounts, and reports on the calculation of the balance in the Flow-through deferral account.

12.2 *EXOGENOUS (Z) FACTORS*

FBC is permitted to adjust the cost of service for "Exogenous Factors" under its PBR Plan. The following criteria have been established for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.301 million, as approved by Commission Order G-182-14.

FBC has identified two new exogenous factors that affect 2018 and 2019 and provides updated costs for MRS which was previously approved as an exogenous factor for 2016 through 2018, all as described below.

12.2.1 Employer Health Tax

Announced as part of the provincial government's Budget in February 2018, the Employer Health Tax (EHT) is a tax levied on businesses' payrolls and will come into effect on January 1, 2019. The EHT is an employer-paid payroll tax based on the remuneration to employees. The tax rate will start at 0.98 percent for annual payrolls in excess of $0.5 million and will gradually increase to 1.95 percent for B.C. payrolls in excess of $1.5 million per year. Details of payment

schedules and rules for aggregating payrolls of related business is still to be determined through pending legislation.

The EHT is a new tax expense for companies in B.C. and meets the exogenous factor criteria identified below.

- The costs are attributable entirely to the provincial government's introduction of the new mandatory payroll tax, which is an event outside the control of a prudently operated utility.
- The costs, which are described in sections 6.3.6 and 7.2.2, are directly and solely attributable to the exogenous event (tax implementation). The tax, introduced for the first time in 2018, was not included in the 2013 base O&M expense or base capital used to determine costs under the PBR formula.
- This exogenous event, which occurs in 2019, could not have been foreseen at the time the base O&M expense and base capital were set.
- The costs are prudently incurred; FBC is legally obligated to comply with tax legislation.
- The costs are estimated at $1.2 million in 2019, which exceed the materiality threshold of $0.301 million. The O&M portion of the EHT is forecast to be $0.576 million, with the remaining $0.624 million in capital.

The actual amount paid will vary depending on FBC's payroll remuneration in 2019 and details of the rules to be determined through pending legislation by the provincial government later this year. Variances between the amounts forecast and actual amounts paid will be returned to or recovered from customers in future years.

12.2.2 MSP Premium Reduction

On December 27, 2017, the provincial government announced the reduction of MSP premiums by 50 percent, effective January 1, 2018, and in the February 2018 provincial budget further announced the elimination of MSP premiums by January 1, 2020.

The MSP premium reduction meets the exogenous factor criteria identified above.

- The savings are attributable entirely to the provincial government's reduction in MSP premiums, which is an event outside the control of a prudently operated utility.
- The savings, which are described in sections 6.3.7 and 7.2.2, are directly and solely attributable to the exogenous event. The premium reduction, implemented in 2018, reduces benefits costs that were included in the 2013 base O&M expense and base capital used to determine costs under the PBR formula.

- This exogenous event, which occurred in 2018, could not have been foreseen at the time the base O&M expense and base capital were set.
- The savings are prudently incurred; MSP premiums are set by provincial legislation.
- The savings are forecast at $0.350 million in 2018 and 2019, which exceeds the materiality threshold of $0.301 million. The O&M portion of the premium reduction is forecast to be $0.168 million in each year, with the remaining $0.182 million in capital.

The actual reductions will vary depending on the number of employees for whom FBC pays the MSP premium in 2018 and 2019. Variances between the amounts forecast and actual reductions will be returned to or recovered from customers in future years.

12.2.3 Mandatory Reliability Standards

FBC will continue to incur incremental O&M and capital requirements in 2018 and future years related to complying with the changes to BC's MRS program approved by Order R-38-15 and R-39-17 regarding Assessment Report No. 8 and Assessment Report No. 10. FBC's 2016, 2017 and 2018 incremental costs to comply with the changes to BC's MRS program were approved for Z-factor treatment by Orders G-202-15, G-8-17, and G-38-18. The MRS costs identified in this Application for exogenous factor treatment in 2019 are for ongoing costs related to Assessment Reports No. 8 and No. 10. The incremental MRS compliance requirements continue to meet the exogenous factor criteria.

- The costs are entirely attributed to complying with the changes to BC's MRS program approved by Orders R-38-15 and R-39-17, which are events outside the control of FBC. These changes were developed by regulatory bodies in the U.S., assessed for adoption by BC Hydro and then adopted by the BCUC. FBC is legally obligated to comply with the new reliability standards.
- As described in section 6.3.4 and 7.2.2, the costs are directly and solely attributable to complying with the changes to the BC MRS program approved by the Commission. These costs have not been previously incurred and were not known at the time the 2013 base O&M was determined and therefore were not included in the 2013 base O&M used to determine the O&M expense included in the PBR formula.
- The costs to comply with the reliability standards that were approved by Orders R-38-15 and R-39-17 could not have been foreseen at the time the 2013 base was set as the new standards were either non-existent or under preliminary development at the time.
- FBC will manage its costs to comply with the reliability standards in a prudent manner and the Commission will have the opportunity to review the costs in subsequent annual reviews.
- For 2019, the incremental MRS costs that qualify for exogenous factor treatment are forecast to be $3.720 million, comprised of $0.940 million in incremental O&M expense

and an incremental $2.780 million in capital expenditures. These costs continue to exceed the Commission-defined materiality threshold of $0.301 million.

As detailed above, FBC's ongoing costs related to Assessment Reports No. 8 and No. 10 satisfy the Z-factor criteria on the same basis as accepted by the Commission in Orders G-202-15, G-8-17 and G-38-18. FBC has therefore forecast these costs outside of the O&M and capital formulas as described in Sections 6.3.4 and 7.2.2 of the Application.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging US GAAP Accounting Guidance

In the PBR Decision, the Commission directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." FBC discusses two US GAAP accounting standards with the impacts set out below:

- For ASU 2016-02 Accounting Standards Codification (ASC) Topic 842 Leases – the accounting assessment of this new standard continues throughout 2018, however the effect on FBC's 2019 Annual Review is not expected to be significant.
- Cloud Computing – as cloud computing accounting guidance continues to evolve, FBC requests approval to capitalize cloud computing implementation costs consistent with traditional on-premise Information Systems (IS) hardware and software for 2019.

12.3.1.1 Leases

In February 2016, FASB issued ASU No. 2016-02, *Leases (ASC Topic 842*) which supersedes lease requirements in ASC Topic 840, *Leases*. The main provision of ASC Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. This standard is effective for FBC beginning on January 1, 2019. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows.

The recognition, measurement and presentation of leases on the statement of earnings will not significantly change from the current US GAAP. The new standard either classifies costs as lease expense for operating leases or interest expense on the lease liability and amortization of the right-of-use asset for finance leases which is consistent with the current guidance.

FBC is currently in the process of assessing its arrangements that qualify as operating leases which will need to be recorded as assets and liabilities on the balance sheet for external financial reporting purposes unless they are determined to be immaterial. FBC's assessments to date have identified its agreements to rent muster stations and office space to be recognized as right-of-use assets and lease liabilities, although the analysis of other agreements will continue throughout 2018. FBC's conclusions on the recognition of its leases under the new standard are subject to final review by the Company's external auditors and could be affected by certain utility industry interpretative issues which remain outstanding.

While FBC's analysis to date does not suggest it is necessary to change how FBC recognizes its lease arrangements for regulatory purposes in its 2019 Annual Review, the final assessments and conclusions could result in timing differences between how FBC recognizes leases for rate-setting purposes and how it is necessary to recognize the leases for external accounting purposes. Since future revenues are reasonably expected to permit recovery or refund of any lease timing differences arising from the implementation of ASC 842 over the term of the lease arrangements in future revenue requirements, FBC would recognize any such timing differences as either a regulatory asset or liability for external financial reporting purposes. As such, for the 2019 Annual Review, FBC has not reflected right-of-use assets, lease liabilities or deferral accounts resulting from the implementation of ASC 842 in its financial schedules.

12.3.1.2 Cloud Computing

FBC is requesting approval of a one-year variance from US GAAP to capitalize cloud computing implementation costs in 2019, consistent with a new accounting standard expected to be effective in 2020.

FBC continues to pursue IS solutions that better meet customer expectations, make business processes more efficient and replace end of life existing IS platforms with cost effective solutions. While these opportunities are initially identified by FBC, the form in which the solution is offered, either through traditional on-premise software or through cloud computing, is not known until discussions occur with the external vendor. An increasing number of IS solutions are being offered in the form of off-premise cloud computing services. Cloud computing includes Software as a Service (SaaS), whereby an entity runs applications from the cloud service provider on a subscription basis, and Infrastructure as a Service (IaaS), whereby an entity procures a subscription for managed infrastructure services, such as servers, from a central provider. Cloud computing services replace traditional on-premise hardware and software that are recognized as capital expenditures for financial statement and regulatory purposes.

Accounting Standards Update 2015-05 Intangibles – Goodwill and Other – Internal – Use Software – Cloud Computing Arrangements (ASU 2015-05) was issued in 2015. This guidance states that if a cloud computing arrangement does not meet the criteria of "having a software license", as defined below, the entity procuring the cloud service should account for the

arrangement as a service contract, which would generally mean expensing such costs. The criteria for an entity "having a software license" is specifically defined as follows:

- The contractual right to take possession of the software at any time during the hosting period without significant penalty, and
- It is feasible for the entity to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software.

Based on *ASU 2015-05*, it is the external vendor costs for implementation performed on the premise of the vendor that are to be expensed pursuant to *ASU 2015-05*. These implementation costs could include the design, setup and configuration of the cloud computing software by the external vendor.

As technology evolves and businesses in all industries continue to obtain the benefits of implementing cloud computing solutions, the shortcomings of *ASU 2015-05* are becoming apparent. This is in part due to the fact that software and hardware purchased as on-premise is not functionally different under cloud computing solutions; rather, it is the location of the asset that is different. Although traditional and cloud computing solutions are functionally the same, *ASU 2015-05* results in recognizing cloud computing implementation costs as O&M. Based on the criteria in *ASU 2015-05*, FBC cannot forecast which of its future cloud computing solutions will have agreements with external vendors that will have provisions that meet the above criteria until the projects are further along in the process. This creates uncertainty from the outset around whether future cloud computing expenditures will be O&M or capital pursuant to *ASU 2015-05*.

The accounting standard setters recognize the need for improvements in the accounting for cloud computing solutions. In June 2018, the Financial Accounting Standards Board (FASB) agreed to issue a final ASU in the third quarter of 2018 based on the March 1, 2018 issuance of the *Exposure Draft: Proposed ASU (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is A Service Contract*. The primary consensus reached for the new ASU is that the capitalization of implementation costs incurred for a cloud computing arrangement that is a service contract is consistent with the capitalization of implementation costs incurred to develop or obtain on-premise software and hardware. The other relevant consensus reached includes the requirement for an entity to expense those implementation costs over the term of the hosting arrangement, which includes periods covered under renewal options that are reasonably certain to be exercised. The new ASU is expected to have an effective date of January 1, 2020.

There is also a recognition in the utility industry that it is appropriate to capitalize cloud-based hardware and software and include such expenditures as capital assets. In 2016, the National Association of Regulatory Utility Commissioners (NARUC) approved the *Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements.* This resolution acknowledged that the utility industry is rapidly

changing and that utilities are having to respond to modern customer expectations and evolutions in technology. The resolution also stated that "the existing regulatory accounting rules may be interpreted, if appropriate, to allow for utilities to capitalize cloud-based software". NARUC encouraged State regulators to consider similar regulatory accounting treatment for cloud computing solutions as it would for on-premise solutions, which would be paid out of a utility's capital budget.

While the new *ASU 350-40* supports the capitalization of initial external vendor cloud computing implementation costs and can be applied retroactively, it is not expected to become effective until 2020. FBC therefore requests approval to adopt the new guidance for rate-setting purposes beginning in 2019. There are a number of benefits of this approach:

- The proposed approach of capitalizing cloud computing implementation costs during 2019 would be consistent with the new *ASU 350-40* that will become effective in 2020.
- The proposed approach would avoid a one-year change in capitalization policies and the associated potential volatility in O&M and capital.
- The proposed approach would remove that uncertainty regarding the treatment of IS implementation costs created by the existing guidance.
- The proposed approach keeps FBC's O&M and capital funding envelopes consistent with the 2013 Base O&M and capital amounts for the final year of the PBR term, which were based on the assumption that IS implementation costs would be capitalized.

FBC is therefore requesting approval for a one-year variance from US GAAP for 2019 to recognize initial cloud computing implementation costs as capital expenditures within the PBR capital formula. This treatment is consistent with the new *ASU 350-40* which becomes effective in 2020 and is consistent with how on-premise computer hardware and software costs have traditionally been recognized for regulatory purposes.

12.4 *NON RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the Commission. The forecast mid-year balance of unamortized non rate base deferred charges is a credit balance of approximately $4.610 million in 2019.

On May 3, 2017, the Commission issued its Regulatory Account Filing Checklist[31]. The purpose of this checklist is to facilitate an efficient review of applications for deferral accounts.

[31] Log No. 53608, Appendix B.

The checklist classifies deferral accounts as either: (a) forecast variance accounts; (b) rate smoothing accounts; (c) benefit matching accounts; (d) retroactive expense accounts; or (e) other. FBC has reclassified its existing non rate base deferral accounts in accordance with the guidelines in Section 11, Schedules 12 and 12.1.

In the following sections, FBC requests approval of three new deferral accounts related to regulatory proceedings. FBC also requests approval of an amendment to one approved deferral account, requests the disposition of three approved deferral accounts, and provides additional information on its Flow-through deferral account.

12.4.1 New Deferral Accounts

FBC seeks approval for three new deferral accounts, all of which are related to regulatory proceedings. Table 12-1 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to deferral accounts for regulatory proceedings.

Consistent with the Commission's decision in the 2012-2013 RRA and the PBR Decision, FBC follows the practice of new deferral accounts being financed using either the short term interest (STI) rate where recovery is over a one-year period; or the weighted average cost of debt (WACD) for longer-term deferrals.

Specific proposals for financing and disposition of the accounts are included in the relevant sections describing the individual accounts.

Table 12-1: Deferral Account Filing Considerations

Item	Consideration	Regulatory Proceeding Costs
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The three regulatory proceeding cost accounts are new deferral accounts, consistent with previously approved regulatory proceeding deferral accounts.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the Commission.

Item	Consideration	Regulatory Proceeding Costs
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the PBR formula O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report on.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the Commission and the degree of involvement of interveners.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the PBR Plan. See sections 12.4.1.1 to 12.4.1.3.

Item	Consideration	Regulatory Proceeding Costs
d)	any impact on intergenerational equity	Generally, FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See sections 12.4.1.1 to 12.4.1.3.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the Commission's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Labour and staff expenses related to regulatory applications are included in formula O&M Expense. See sections 12.4.1.1 to 12.4.1.3.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FBC amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See sections 12.4.1.1 to 12.4.1.3.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Consistent with the Commission's decision in the 2012-2013 RRA and the PBR Decision, FBC has followed the practice of new deferral accounts being financed using either the short term interest (STI) rate where recovery is over a one-year period, or the weighted average cost of debt (WACD) for longer-term deferrals. See sections 12.4.1.1 to 12.4.1.3.
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral accounts can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings.

12.4.1.1 2018 Demand Side Management (DSM) Expenditure Schedule

FBC filed its 2018 DSM Expenditure Schedule on November 15, 2017. Following a written public hearing the expenditure schedule was accepted by Order G-113-18 on June 15, 2018. FBC incurred $0.073 million ($0.054 million after tax) in external costs for the review of this application.

FBC seeks approval of a deferral account attracting a STI rate of return to capture these costs and proposes to amortize the costs over one year, in 2019.

12.4.1.2 Rate Design and Rates for Electric Vehicle (EV) Direct Current Fast Charging Service Application

On March 16, 2018 FBC filed an application for approval of a new rate schedule for EV Charging Service at FBC-owned EV charging stations. By Order G-9-18 the Commission approved interim rates for the charging service and adjourned the proceeding. FBC expects the proceeding to resume following the conclusion of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service.

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.

12.4.1.3 BC Hydro Waneta 2017 Transaction

BC Hydro filed an application on October 30, 2017 to acquire the remaining two-thirds interest in the Waneta Dam and associated assets. 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.

FBC is seeking approval of a deferral account attracting a STI return to capture the costs of participation and proposes to amortize the costs over one year, in 2019.

12.4.2 Existing Deferral Accounts

Below, FBC requests an amendment to one deferral account, proposes the amortization of three other existing accounts, and provides information on the Flow-through deferral account.

12.4.2.1 2018 – 2019 Revenue Surplus Deferral Account

As part of the Annual Review for 2018 Rates, FBC received approval through Order G-131-18 to establish the 2018 Revenue Deficiency deferral account to capture the 2018 revenue deficiency of $0.896 million ($0.654 million after tax) resulting from maintaining 2018 rates at existing 2017 levels. The account is approved to attract a STI rate of return. As directed in Order G-131-18 FBC is to propose the disposition of this account in its Annual Review for 2019 Rates.

FBC is forecasting a 2019 revenue surplus of $5.759 million ($4.204 million after tax) as shown in the financial schedules.[32] FBC seeks approval to add the forecast 2019 revenue surplus to the 2018 Revenue Deficiency account and re-name the account the 2018 – 2019 Revenue Surplus account. The following table summarizes the 2018 and projected 2019 additions to the deferral account and the projected 2019 ending balance of $3.550 million (credit). FBC will propose the amortization of this account in a future application in order to mitigate future rate increases.

Table 12-2: 2018 – 2019 Revenue Surplus Deferral Account

Line No.	Description		
1	2018 Revenue Deficiency (G-131-18)	$	0.654
2	2019 Projected Revenue Surplus		(4.204)
3	Total Revenue Surplus to be returned in future years	$	(3.550)

FBC also requests approval to apply a WACD rate of return to this account, effective January 1, 2019. Since the 2018 revenue deficiency is not being amortized at this time, a WACD rate of return is consistent with the treatment of FBC's other multi-year deferral accounts.

12.4.2.2 2019 – 2022 DSM Expenditures Application

Order G-38-18 approved the creation of the Multi-Year DSM Expenditures Schedule deferral account[33]. FBC filed its Application for Acceptance of DSM Expenditures for 2019 to 2022 on August 2, 2018. A written public hearing is anticipated for the review of this application; FBC estimates it will incur costs for Commission and intervener costs, consulting and legal fees and other external costs of $0.275 million ($0.202 million after tax).

FBC proposes to amortize this account over a four-year period beginning in 2019 which is the term to be covered by the expenditure schedule.

12.4.2.3 2017 Cost of Service Analysis and Rate Design Application (COSA/RDA)

Order G-202-15 approved the creation of a deferral account to capture the external costs for the preparation and review of the Company's COSA/RDA. FBC filed the application on December 22, 2017 and expects to incur $1.520 million ($1.110 million after tax) for Commission and intervener costs, consulting and legal fees and other external costs for a written public hearing on the COSA/RDA.

[32] Section 11, Schedule 1, Line 31

[33] The multi-year DSM Expenditure Schedule application was expected to include 2018 and future years. As a result of a later than expected decision on FBC's Long Term Electric Resource Plan and Long Term DSM Plan, FBC filed a single year DSM expenditure schedule application for 2018 (see section 12.4.1.1). The Multi-Year DSM encompasses the 2019 -2022 timeframe.

FBC proposes to amortize the account over a five-year period beginning in 2019; this amortization period is consistent with that generally used for rate design applications by FBC and consistent with the anticipated time between filing a COSA and RDA.

12.4.2.4 Castlegar Office Disposition Deferral Account

On August 3, 2017, FBC applied for approval from the Commission to sell the Castlegar District Office (CDO) property and provide the net proceeds to customers. Order G-153-17 established the Castlegar Office Disposition deferral account to record the net proceeds (sale proceeds, net of disposal costs and taxes payable, less the net book value of the land and buildings). The sale of the CDO was completed on January 18, 2018 for $1.000 million. The net book value of the CDO property transferred on that date was $0.395 million and the final credit balance in the deferral account (after disposal costs and taxes) is $0.439 million.

In accordance with the approving order, this account is financed at FBC's STI rate. FBC proposes to amortize the account over one year, in 2019.

12.4.2.5 Flow-Through Deferral Account

As approved by Commission Order G-163-14, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are included in rates on a forecast basis and which do not have a previously approved deferral account. The specific items included in the Flow-through account were set out in Table 1, which was included in FBC's letter Response to Orders G-162-14 and G-163-14 filed with the Commission on November 7, 2014 reproduced below.

Table 12-3: Variances Captured in the Flow-through Deferral Account[34]

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
Gross O&M:		
Formula driven O&M variances	Earnings sharing	Earnings sharing
BCUC fees variances	BCUC Variances deferral	Flow-through deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances *	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	N/A - no variance	N/A - no variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Depreciation and Amortization:		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
Other Revenues (FEI)/Other Income (FBC):		
SCP Mitigation Revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
All other other revenue/income variances	Flow-through deferral	Flow-through deferral
Wheeling (FBC)/Transportation costs (FEI):		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
Income Tax:		
Income tax variances	Flow-through deferral	Flow-through deferral
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas Storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
All other interest variances	Flow-through deferral	Flow-through deferral

* Including items re-forecast outside of the formula such as insurance premiums, AMI, NGT stations, Biomethane, RS46 O&M

In accordance with the method set out in the table above, the calculation of the 2018 projected Flow-through amount of $10.534 million credit is shown in Table 12-4 below. To calculate the amount to be distributed to customers, FBC has also included an adjustment for the difference between the projected ending 2017 deferral account credit balance of $7.102 million embedded in 2018 rates and the actual ending 2017 deferral account credit balance of $9.356 million, a credit difference of $2.254 million. FBC notes that the financing return on this account is

[34] FBC notes an error in the table that was filed. Although for FEI the BCUC fee variances are recorded in a separate deferral account, for FBC these fees are included in formula O&M. As such, for FBC, any variance in these fees between the formula-driven amount and the actuals will be subject to earnings sharing, and not to flow-through treatment.

included in the aggregate financing of deferral accounts financed at the STI rate at Section 11, Schedule 12, Line 33.

Table 12-4: 2018 Flow-through Deferral Account Additions ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Variance
1	Revenue	$ (356.340)	$ (366.184)	$ (9.844)
2				
3	Power Purchase Expense	133.071	130.247	(2.824)
4				
5	Wheeling	5.171	5.281	0.110
6				
7	Water Fees	10.208	10.287	0.079
8				
9	O&M Tracked Outside of Formula			
10	Insurance Premiums	1.265	1.246	(0.019)
11	Advanced Metering Infrastructure Project	(1.139)	(1.139)	-
12	Mandatory Reliability Standards Incremental O&M	1.070	1.040	(0.030)
13	Upper Bonnington Unit 3 Annual Inspection	(0.040)	(0.040)	-
14	MSP Premium Reduction	-	(0.168)	(0.168)
15				
16	Property Tax	16.684	16.143	(0.541)
17				
18	Depreciation and Amortization	52.667	52.995	0.328
19				
20	Other Revenue	(8.416)	(9.609)	(1.193)
21				
22	Interest Expense	40.059	40.059	-
23				
24	Income Tax	9.633	13.225	3.592
25				
26	Working Capital Adjustment for AMI			(0.024)
27				
28	2018 After-Tax Flow-Through Addition to Deferral Account			(10.534)
29				
30	2017 Ending Deferral Account Balance True-Up			$ (2.254)
31	2019 After-Tax Amortization			$ (12.788)

The variance in revenue is due to loads being higher than approved as a result of higher than forecast customer growth, higher residential UPC and the addition of one new industrial customer. The reduction in 2018 projected power purchase expense is primarily due to additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost. Variances in wheeling and water fees are shown in Section 4. Variances in Other Revenue are shown in Section 5. Variances in O&M tracked outside of formula are shown in Section 6, and variances in Property Taxes are shown in Section 9. Depreciation and amortization expense is close to the approved value. Interest expense is projected to be at the approved amount. Finally, the variance in income taxes is due to the income tax impacts of

each of the aforementioned items and the variance between the projected and approved tax timing differences.

The true-up of $2.254 million between the projected ending 2017 Flow-Through deferral account balance embedded in 2018 rates and the actual ending 2017 deferral account balance is primarily the net result of higher sales revenue net of power purchase expense due to weather-related increases in load, in addition to higher savings on market purchases of power. Similarly, an adjustment to include the difference between the projected and final actual amounts for 2018 subject to flow-through treatment will be recorded in the deferral account in 2019 and amortized in 2020 rates.

12.5 *SUMMARY*

FBC has identified two new exogenous events and updated the costs associated with the MRS exogenous events which affect rates in 2019, and proved updates on certain accounting related matters. In this section, FBC has also requested approvals related to three new and four existing non-rate base deferral accounts and included information on the Flow-through deferral account.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

SQIs form the basis of determining a utility's quality of service and represent a broad range of business processes that are important elements to the customer experience. Under the PBR Plan, SQIs are used to monitor the utility's performance to ensure that any cost reductions by the utility as a result of implementing productivity initiatives do not result in serious degradation of the quality of service to customers during the PBR period.

The Commission approved a balanced set of SQIs covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the Commission in Order G-14-15. Three of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

In 2016, the Commission issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The Commission determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The Commission stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

In the subsections below, FBC reports on its 2017 and June 2018 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2017, for the eight SQIs with benchmarks, seven performed at or better than the approved benchmarks with the remaining one, the System Average Interruption Duration Index (SAIDI), performing poorer than the threshold primarily due to the implementation of the Outage Management System (OMS) which automated the tracking of outage data, and due to wildfires. For the three SQIs that are informational only, performance is generally consistent with recent years' performance.

The 2018 year-to-date performance is similar to 2017, with seven of the eight SQIs with benchmarks performing at or better than the approved benchmarks, and SAIDI continuing to perform poorer than the threshold due to the implementation of the OMS and snow storms.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2017 and June year-to-date performance for 2018 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation that was approved by the Commission. Actual 2017 and June year-to-date results for 2018 are also provided for the three informational SQIs.

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2017 Results	2018 June YTD Results
	Safety SQIs				
Emergency Response Time	Percent of calls responded to within two hours	93%	90.6%	93%	93%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64	2.39	1.27	1.61
	Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	72%	80%	81%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.15	0.20
Meter Reading Accuracy	Number of scheduled meters that were read	97%	94%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	70%	70%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.2	8.2
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	4.7%	5.0%
	Reliability SQIs				
System Average Interruption Duration Index (SAIDI) – Normalized	3 year average of SAIDI (average of cumulative customer outage time)	2.22	2.62	2.76	3.26

Performance Measure	Description	Benchmark	Threshold	2017 Results	2018 June YTD Results
System Average Interruption Frequency Index (SAIFI) - Normalized	3 year average of SAIFI (average customer outage)	1.64	2.50	1.56	1.63
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.6%	0.3%

In the following sections, FBC reviews each SQI's individual performance in 2017 and 2018. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time including conditions such as time of day (during business hours or after business hours), number and type of events (i.e. widespread outages), available resources and location (travel times and traffic congestion) and weather conditions.

The 2017 result was 93 percent which met the benchmark of 93 percent.

In October 2017, a new workforce management tool was implemented which changed the process for how trouble orders are created and dispatched to FBC field crews. The new tool gives increased visibility into the status of trouble orders, allows for near real-time feedback of the status of work on site and improves integration with other internal business systems.

The June 2018 year-to-date result remains on track at the benchmark level of 93 percent. In 2018 to date there has been a higher than normal volume of trouble calls, particularly in the West Kootenay region. A series of winter and early spring storms have led to a 30 percent

higher than normal trouble volume for this area. North and South Okanagan trouble volume is at or below historical average thus far in 2018.

The Company's 2009 to 2017 annual and 2018 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the types of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Results	92%	95%	92%	91%	94%	91%	92%	97%	93%	93%
Benchmark	n/a	n/a	n/a	n/a	n/a	93%	93%	93%	93%	93%
Threshold	n/a	n/a	n/a	n/a	n/a	90.6%	90.6%	90.6%	90.6%	90.6%

All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e. one or more days missed from work) and medical treatments (i.e. medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three year rolling average of the annual results.

The 2017 annual (calendar year) AIFR result was 1.13, resulting in a three-year rolling average of 1.27 in 2017, which is better than the benchmark of 1.64. Five recordable incidents occurred in 2017. The June 30, 2018 YTD AIFR result is 2.56. As of June 30, 2018, there were 2 Medical Treatment and 4 Lost Time injuries. Four of these six events occurred in January. If the recent improving trend in performance continues, FBC expects the 2018 AIFR to improve over the course of the year. The three-year rolling average of annual results including 2018 June year-to-date results is 1.61, which is better than the benchmark of 1.64.

Safety continues to be a core value for FBC and prevention of injury remains a key focus. FBC continues to focus on and reinforce the fundamentals of safety through effective safe work planning identifying hazards and mitigating risks, detailed work observations and thorough event analysis capturing learnings and identifying opportunities for continued improvement. FBC has a robust Safety Management System (SMS) that addresses the hazard and risk requirements of a safe workplace and identifies opportunities for improvement in the Company's safety culture. FBC continues to maintain the Certificate of Recognition (COR) through audits performed annually, providing validation of the effectiveness of the Company's SMS and related safety

programs. The COR, administered by the Partners in Injury and Disability Prevention Program of WorkSafeBC, is a voluntary initiative that recognizes and rewards employers who meet the requirements of the Occupational Health and Safety Regulations and commit to continual improvement of their SMS to enhance safety performance.

Target Zero is the continual improvement program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing SMS and engage employees at all levels in safety as well as promote an interdependent safety environment. The Company believes this program has contributed to the positive safety trend experienced.

The Company's 2009 to 2017 and 2018 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	1.41	1.72	1.48	1.72	2.82	3.21	1.54	1.15	1.13	2.56
Three year rolling average	2.00	2.00	1.54	1.64	2.01	2.58	2.52	1.97	1.27	1.61
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	2.39	2.39	2.39	2.39	2.39

The annual results in Table 13-3 support the conclusion that the higher AIFR results in 2013 and 2014 are anomalous in nature. FBC's 2015, 2016 and 2017 annual results are materially improved as compared to 2013 and 2014 and have returned to pre-2013 levels.

FBC remains committed to maintaining its focus on safety. FBC believes that its actions to increase the focus on safety are having a positive impact on the AIFR.

13.2.2 Responsiveness to Customer Needs

First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2017 result was 80 percent and better than the benchmark at 78 percent. June 2018 year-to-date performance is 81 percent and remains better than the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	n/a	n/a	n/a	n/a	73%	73%	76%	79%	80%	81%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	72%	72%	72%	72%	72%

Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date):
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2017 result was 0.15 which was better than the benchmark of 5.0. The June 2018 year-to-date performance is 0.20 which is also better than the benchmark. No significant billing issues have arisen in 2018.

The 2017 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2017 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	100.00%	If (PA ≥99.9%,5000*(1 - PA),1.05-PA))	=5000*(1-1)	0
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	99.55%	(100%-PA)*100	=(100%-99.55%)*100	0.45
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+0.45) /3	**0.15**

The Company's 2014 to 2017 annual and 2018 year-to-date results are provided below. As tracking of this SQI began part way through 2013, the 2013 results do not reflect a full year.

Table 13-6: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	n/a	n/a	n/a	n/a	0.10	2.34	0.39	0.57	0.15	0.20
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0	5.0

Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2017 result was 99 percent, better than the benchmark. The June 2018 YTD result is 99 percent, also better than benchmark

The Company's 2009 to 2017 and 2018 year-to-date results are provided below. Historically, there has been little variation in performance other than in 2013, which saw a significant drop in performance (to 51 percent) as the result of the six-month IBEW labour disruption.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	98%	98%	98%	98%	51%	98%	96%	99%	99%	99%
Benchmark	n/a	n/a	n/a	n/a	n/a	97%	97%	97%	97%	97%
Threshold	n/a	n/a	n/a	n/a	n/a	94%	94%	94%	94%	94%

Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2017 result was 70 percent, which met the benchmark of 70 percent. The June 2018 year-to-date performance is at 70 percent which meets the benchmark.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by the events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	70%	70%	70%	70%	70%	48%	71%	70%	70%	70%
Benchmark	n/a	n/a	n/a	n/a	n/a	70%	70%	70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	68%	68%	68%	68%	68%

Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The Index includes feedback from both residential and commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage. Over the last several years, customer concerns about tiered electricity prices, collection policies and advanced metering have contributed to the overall erosion of CSI scores seen in Table 13-9 below. Recent years' index scores have stabilized.

The 2017 year-end result was 8.2, the same as the 8.2 score in 2016. Results were lower in three areas (satisfaction with the accuracy of meter reading, satisfaction with energy conservation info and satisfaction with field services), higher in one (satisfaction with the contact centre), and static in one area (overall satisfaction).

The June 2018 year-to-date average index score was 8.2, slightly higher than the 8.1 score for the same period last year. Of the five measures that make up the overall score, results were higher in four, and lower in one category. Customer attitudes about the Company's accuracy of meter reading metric increased by four points from 7.5 for June 2017 year-to-date to 7.9 for June 2018 year-to-date. Small increases in scores were seen for overall satisfaction, energy conservation information and field services metrics. Overall satisfaction increased from 7.9 to 8.0, energy conservation information increased from 7.2 to 7.3, and field services went from 8.8 to 8.9. The score for the satisfaction with the contact centre metric decreased from 8.3 in June 2017 year-to-date to 8.1 in June 2018 year-to-date.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	8.6	8.8	8.7	8.4	8.0	8.1	8.1	8.2	8.2	8.2
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Telephone Abandon Rate

The Telephone Abandon Rate, an informational indicator, measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information

through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

The 2017 result was 4.7 percent and the June 2018 year-to-date result is 5.0 percent.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. As discussed in the 2015 Annual Review, the 2014 result of 12.4 percent was negatively impacted by high call volumes resulting from the first verified meter readings occurring after the IBEW labour disruption ended in December of 2013, the introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers. FEI attributes the increase in the abandon rate in recent years to an increase in customers using the self-serving option through the interactive voice response messages during power outages. Customers who receive the required information through the automated messaging abandon the call without needing to speak with a FortisBC representative.

Table 13-10: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	2.2%	1.9%	1.7%	1.9%	2.0%	12.4%	2.7%	3.9%	4.7%	5.0%
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

In August of 2016, FortisBC implemented a new feature where customers can retain their place in the telephone queue by entering their phone number and requesting a call back. As soon as it is their turn in line, the system dials the recorded number and connects the customer with a Customer Service Representative (CSR).

In Appendix A to Order G-8-17, the Commission Panel directed FBC to include in its Annual Review for 2018 Rates a discussion of the impact, if any, that the new call back option has had on the Telephone Abandon Rate Service Quality Indicator and to discuss whether there are other measures, such as "Time Until Call Back is Received," which may provide additional value to FBC's existing informational indictors. Below, FBC provides an update to the information provided in the Annual Review for 2018 Rates.

In 2017, the new call back option was selected approximately 3,556 times, representing approximately three percent of the customers who called each month. In 2018 to the end of June, the new call back option has been selected approximately 1,629 times, representing approximately three percent of the customers who called each month year-to-date. It is not possible to distinguish between the average wait-time for customers utilizing the call back feature from the wait time of those not using the feature. The measurement of "Time Until Call Back is Received" is therefore not available. As described above, there are many other reasons a call may be abandoned other than waiting time, the most frequent being the use of avoidance messages on the IVR during outages. Since the number and size of outages are variable from

year to year, it is impossible to determine the impact that the call-back feature alone had on the abandon rate.

13.2.3 Reliability

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e. the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

Both the 2017 annual and 2018 year-to-date SAIDI results have been influenced by the implementation of the OMS, a system used to record distribution outages based on the Outage Start Time. The OMS replaced a manual system and has automated the tracking and reporting of outage data through integration with the FBC AMI system. With the previous system, the Outage Start Time was recorded as the time that the outage was confirmed in the field. With the OMS, the Outage Start Time is based on the earliest AMI or customer call-in for the outage. With the change to the OMS and a different definition to the Outage Start Time, the reported outage times have increased, causing the SAIDI values reported to increase, even though there has been no change in the company's operating practices. FBC estimates the increase in reported values for SAIDI as the result of the OMS to be in the 15 to 30 percent range, consistent with other utilities' experience who have replaced their manual systems with an OMS. FBC identified the potential for this outcome in its 2014 Service Quality Indicator Consultation Process Compliance Filing. 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".

FBC's 2017 annual SAIDI performance was 4.05, and higher than the three-year average. The 2017 three-year rolling average was 2.76 which was higher than the threshold value of 2.62. As discussed earlier, the OMS implementation has increased reported SAIDI results. In addition, the 2017 SAIDI results were impacted by wildfires. Specifically, wildfires in the Princeton and Joe Rich areas of the Okanagan accounted for approximately 78,000 customer hours or 15 percent of the annual SAIDI. None of the wildfires in 2017 met the threshold for normalization (i.e. none qualified as a major event such that they would be excluded from the SAIDI calculation). If SAIDI were normalized for the estimated impact of the OMS, FBC's three-year rolling average SAIDI result for 2017 would be better than the threshold.

For 2018, FBC's January to June 2018 SAIDI performance was also higher than the historical three-year average. In addition to the OMS, the main contributor for higher SAIDI was the reliability of the transmission system in the first quarter of 2018. The normalized transmission system customer hours related to outages was over four times higher than the previous three-year average mainly due to adverse weather related outages. A series of large snow fall events in late January severely impacted SAIDI results, while no single day met the threshold for normalization (approximately 45,000 customer hours per event). From January 23 to January 29, the system experienced multiple snowfall-related outages that exceeded 55,000 customer hours. Additionally, on January 17, a forestry worker near a transmission line right of way caused an outage that resulted in 27,000 customer hours.

The Company's 2009 to 2017 and 2018 year-to-date results are provided below. Note that the results can be influenced by uncontrollable events such as storms that occur in a year.

Table 13-11: Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.76	3.26
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62	2.62	2.62

System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e. the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purposes of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2017 three-year rolling average result was 1.56, which is better than the benchmark of 1.64. The June 2018 year-to-date result is 1.63, which also is better than the benchmark. Similar to the SAIDI results, both the 2017 annual and 2018 year to date SAIFI results have been influenced, although to a lesser degree, by the implementation of the OMS, which has eliminated even the small number of outages that may previously have been inadvertently omitted from the manually-maintained outage statistics.

The Company's 2009 to 2017 and 2018 year-to-date results are provided below. From 2009 to 2017, performance has generally been stable.

Table 13-12: Historical SAIFI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Three year rolling average results	1.87	1.96	1.71	1.64	1.31	1.39	1.49	1.51	1.56	1.63
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	2.50	2.50	2.50	2.50	2.50

Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

The 2017 result for GFOR was 0.6 percent and is mainly attributable to equipment failures at Upper Bonnington and Corra Linn plants. The failures included UBO Unit 1 outages caused by governor issues in April and an oil leak in June and an outage on COR Unit 3 on November 17th caused by a Potential Transformer failure. The GFOR for 2018 year-to-date is 0.3 percent and is mainly attributable to equipment failures at the Upper Bonnington plant related to governor issues on Unit 5.

The Company's 2009 to 2017 annual and 2018 year-to-date results are provided below. The 2013 and 2014 results are higher than the other years due to forced outages arising from fires

at the Corra Linn and South Slocan generating plants. Also shown is the comparable data from CEA, demonstrating that FBC's results, other than 2013, have been much lower than the industry average.

Table 13-13: Historical Generator Forced Outages

	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
FBC	0.9%	0.1%	0.1%	0.5%	5.2%	1.7%	0.1%	0.9%	0.6%	0.3%
CEA	1.8%	3.9%	5.0%	4.9%	4.9%	6.3%	6.2%	6.2%	n/a[35]	

13.3 *REVIEW OF 2017 PERFORMANCE OF SERVICE QUALITY INDICATORS*

In summary, FBC's 2017 results and June 2018 year-to-date SQI results indicate that the Company's overall performance meets service quality standards. In 2017, for the eight SQIs with benchmarks, seven performed at or better than the approved benchmarks with one, SAIDI performing poorer than the threshold. As discussed earlier, the implementation of the OMS and the change in how outage times are recorded have caused the SAIDI values reported to increase, even though there has been no change in the company's practices. Normalizing for the estimated impact of the OMS would result in a three-year rolling average SAIDI result for 2017 that would have been better than the threshold. For the three SQIs that are informational only, performance is generally consistent with recent years' performance.

[35] The final CEA report is generally available in the third quarter of the following year.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

Français

Statistics Canada Statistique Canada

Search website

Subjects | Data | Analysis | Reference | Geography | Census program | Surveys and statistical programs | About StatCan | Canada.ca

Home → Data → Consumer Price Index, monthly, not seasonally adjusted → Add/Remove data

Add/Remove data

Consumer Price Index, monthly, not seasonally adjusted[1,2]

Frequency: Monthly

Table: 18-10-0004-01 (formerly CANSIM 326-0020)

Geography: Canada, Census metropolitan area, Census metropolitan area part, Census subdivision, Province or territory

► Customize table (Add/Remove data)

Download

	British Columbia (map)
Reference period	**All-items**
	2002=100
July 2016	123.3
August 2016	123.4
September 2016	123.2
October 2016	123.1
November 2016	122.7
December 2016	122.7
January 2017	123.5
February 2017	123.6
March 2017	124.2
April 2017	124.4
May 2017	125.0
June 2017	125.2
July 2017	125.6
August 2017	125.9
September 2017	125.7
October 2017	125.6
November 2017	125.9
December 2017	125.2
January 2018	126.1
February 2018	127.0
March 2018	127.4
April 2018	127.7
May 2018	128.4
June 2018	128.6

How to cite: Statistics Canada. Table 18-10-0004-01 Consumer Price Index, monthly, not seasonally adjusted

Table A1-2: CANSIM Table 281-0063

Français

Statistics Canada Statistique Canada

Search website

Subjects | Data | Analysis | Reference | Geography | Census program | Surveys and statistical programs | About StatCan | Canada.ca

Home → Data → Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted → Add/Remove data

Add/Remove data

Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted[1 2 3 4 5]

Frequency: Monthly

Table: 14-10-0223-01 (formerly CANSIM 281-0063)

Geography: Canada, Province or territory

► Customize table (Add/Remove data)

Download

	British Columbia (map)	
	Average weekly earnings including overtime for all employees [6]	
Reference period	Industrial aggregate including unclassified businesses [6 7]	Industrial aggregate excluding unclassified businesses [6 7]
	Dollars	
July 2016	..	916.30[A]
August 2016	..	922.72[A]
September 2016	..	919.27[A]
October 2016	..	918.42[A]
November 2016	..	927.27[A]
December 2016	..	931.13[A]
January 2017	..	930.35[A]
February 2017	..	930.17[A]
March 2017	..	934.96[A]
April 2017	..	936.88[A]
May 2017	..	940.14[A]
June 2017	..	944.40[A]
July 2017	..	937.98[A]
August 2017	..	941.65[A]
September 2017	..	952.43[A]
October 2017	..	952.38[A]
November 2017	..	952.81[A]
December 2017	..	957.62[A]
January 2018	..	956.68[A]
February 2018	..	958.80[A]
March 2018	..	963.03[A]
April 2018	..	952.75[A]
May 2018	..	959.86[A]

Symbol legend:

.. : not available for a specific reference period

A : data quality: excellent

Table A1-3: British Columbia Forecast Gross Domestic Product
Conference Board of Canada, Provincial Outlook Economic Forecast, Winter 2018

Table 1a

Key Economic Indicators: British Columbia, 2017–19

(forecast completed February 13, 2018)

	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2017	2018	2019
GDP at market prices ($ millions)	276,138	276,193	278,340	282,949	288,440	292,428	295,855	298,732	300,917	303,530	306,333	309,316	278,405	293,864	305,024
	0.8	*0.0*	*0.8*	*1.7*	*1.9*	*1.4*	*1.2*	*1.0*	*0.7*	*0.9*	*0.9*	*1.0*	*5.6*	*5.6*	*3.8*
GDP at market prices (2007 $ millions)	242,758	246,110	247,648	249,740	251,605	253,347	254,791	256,025	256,701	257,698	258,905	260,303	246,564	253,942	258,402
	0.3	*1.4*	*0.6*	*0.8*	*0.7*	*0.7*	*0.6*	*0.5*	*0.3*	*0.4*	*0.5*	*0.5*	*2.4*	*3.0*	*1.8*
GDP at basic prices (2007 $ millions)	221,815	225,268	226,930	228,961	230,680	232,298	233,640	234,794	235,448	236,404	237,552	238,875	225,744	232,853	237,070
	0.5	*1.6*	*0.7*	*0.9*	*0.8*	*0.7*	*0.6*	*0.5*	*0.3*	*0.4*	*0.5*	*0.6*	*2.8*	*3.1*	*1.8*
Consumer price index (2002 = 1.0)	1.238	1.249	1.257	1.256	1.261	1.268	1.275	1.282	1.290	1.296	1.303	1.310	1.250	1.272	1.300
	0.8	*0.9*	*0.7*	*–0.1*	*0.4*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.5*	*2.1*	*1.7*	*2.2*
Implicit price deflator—GDP at market prices (2007 = 1.0)	1.138	1.122	1.124	1.133	1.146	1.154	1.161	1.167	1.172	1.178	1.183	1.188	1.129	1.157	1.180
	0.5	*–1.3*	*0.2*	*0.8*	*1.2*	*0.7*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*3.1*	*2.5*	*2.0*
Wages and salary per employee ($ 000s)	47.3	47.3	48.0	48.6	48.8	49.1	49.5	49.8	50.1	50.4	50.8	51.1	47.8	49.3	50.6
	0.5	*0.0*	*1.5*	*1.1*	*0.5*	*0.6*	*0.7*	*0.7*	*0.6*	*0.6*	*0.8*	*0.7*	*2.5*	*3.1*	*2.7*
Primary household income ($ millions)	196,046	199,578	201,594	204,232	206,058	208,387	210,563	212,672	214,617	216,420	218,680	220,836	200,362	209,420	217,638
	1.2	*1.8*	*1.0*	*1.3*	*0.9*	*1.1*	*1.0*	*1.0*	*0.9*	*0.8*	*1.0*	*1.0*	*6.2*	*4.5*	*3.9*
Household disposable income ($ millions)	170,722	174,150	176,151	177,993	179,530	181,179	182,811	184,492	185,763	187,313	189,205	191,030	174,754	182,003	188,328
	0.3	*2.0*	*1.1*	*1.0*	*0.9*	*0.9*	*0.9*	*0.9*	*0.7*	*0.8*	*1.0*	*1.0*	*6.8*	*4.1*	*3.5*
Household net savings rate (per cent)	0.5	0.0	–0.6	–1.1	–1.4	–1.8	–2.0	–2.2	–2.2	–2.2	–2.2	–2.2	–0.3	–1.8	–2.2
Population (000s)	4,783	4,796	4,817	4,841	4,844	4,855	4,866	4,876	4,887	4,897	4,907	4,917	4,809	4,860	4,902
	0.1	*0.3*	*0.4*	*0.5*	*0.1*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.3*	*1.1*	*0.9*
Employment (000s)	2,434	2,469	2,478	2,480	2,489	2,502	2,509	2,514	2,517	2,519	2,524	2,529	2,465	2,504	2,522
	1.1	*1.5*	*0.4*	*0.1*	*0.4*	*0.5*	*0.3*	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*3.6*	*1.6*	*0.7*
Labour force (000s)	2,576	2,609	2,609	2,607	2,616	2,621	2,626	2,630	2,635	2,641	2,645	2,653	2,600	2,623	2,644
	0.7	*1.3*	*0.0*	*–0.1*	*0.4*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.3*	*2.7*	*0.9*	*0.8*
Labour force participation rate (per cent)	65.1	65.7	65.4	65.1	65.3	65.3	65.2	65.2	65.2	65.2	65.2	65.2	65.3	65.2	65.2
Unemployment rate (per cent)	5.5	5.4	5.0	4.9	4.9	4.5	4.4	4.4	4.5	4.6	4.6	4.7	5.2	4.6	4.6

(continued ...)

Appendix A-2

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. Tables 2.1 to 5.2 show ten years of historical data and the before-savings and after-savings forecast for 2018 and 2019. Table 5.3 shows the DSM and Other-Savings that were deducted from the before-savings forecast to provide the after-savings forecast for 2019. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2012 to 2017 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2012. Table 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2015 to 2017. Finally Table 6.6 shows the system load factor from the years 2012 to 2017 and the forecast load factor for 2018 and 2019.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and all other savings (AMI[1], CIP[2], and rate-driven impacts);
- after-savings – the load after DSM and all other savings (AMI, CIP, and rate-driven impacts).

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2008	351,478	312,547	288,943	248,550	243,211	235,861	276,961	258,486	223,859	260,879	300,150	349,985	3,350,908
2009	357,560	302,739	305,539	244,978	242,249	242,735	276,801	262,866	234,668	269,945	315,009	360,679	3,415,766
2010	358,574	304,251	288,022	253,247	237,451	232,285	274,190	265,937	227,770	258,133	303,172	365,668	3,368,701
2011	374,096	313,764	312,059	254,039	235,722	242,276	268,421	273,732	242,593	260,877	307,093	362,607	3,447,280
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
Before-Savings													
2018S	375,867	318,166	310,351	271,511	254,969	257,255	300,902	287,532	245,077	270,253	332,394	364,336	3,588,615
2019F	382,006	323,421	315,383	275,979	258,728	261,383	305,777	291,970	248,941	274,371	337,800	370,225	3,645,985
After-Savings													
2018S	375,110	317,301	309,324	270,456	253,868	256,030	299,500	285,925	243,217	268,038	329,823	361,408	3,569,998
2019F	378,987	320,293	312,160	272,792	255,552	258,100	302,316	288,257	244,939	270,008	333,084	365,143	3,601,632

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2008	313,562	279,252	262,392	227,860	223,882	217,082	252,395	236,852	206,815	238,874	270,905	312,359	3,042,230
2009	318,969	271,732	276,533	225,115	223,331	223,208	252,599	240,861	216,326	246,835	283,506	321,479	3,100,494
2010	322,764	275,389	264,054	233,827	220,707	215,751	252,308	245,260	211,831	238,568	276,095	328,561	3,085,116
2011	333,975	282,076	283,208	233,733	218,542	223,679	246,555	251,059	223,951	240,135	278,304	324,686	3,139,902
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
Before-Savings													
2018S	340,488	289,792	285,480	251,556	237,723	239,210	277,416	265,948	228,599	251,023	303,372	330,918	3,301,526
2019F	346,041	294,568	290,106	255,689	241,247	243,049	281,908	270,064	232,207	254,862	308,301	336,264	3,354,307
After-Savings													
2018S	340,133	289,269	284,806	250,817	236,924	238,296	276,395	264,715	227,080	249,218	301,310	328,558	3,287,522
2019F	343,852	292,161	287,608	253,153	238,686	240,384	279,170	267,054	228,847	251,244	304,480	332,163	3,318,802

[1] Advanced Metering Infrastructure
[2] Customer Information Portal

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2008	136,053	115,157	109,364	89,438	80,721	72,251	97,949	85,591	74,307	91,773	109,092	133,820	1,195,516
2009	138,654	111,321	124,105	89,024	87,454	83,579	97,792	88,147	71,111	92,827	114,789	140,106	1,238,909
2010	144,415	116,176	112,135	94,505	85,285	75,333	96,222	91,300	72,613	94,047	110,964	148,667	1,241,663
2011	150,580	112,169	121,527	98,312	80,093	79,957	85,233	91,744	76,608	88,720	117,345	146,806	1,249,094
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
Before-Savings													
2018S	151,840	122,053	120,644	100,726	89,892	87,737	108,830	98,865	79,744	100,178	132,004	148,125	1,340,638
2019F	153,544	123,424	121,998	101,857	90,901	88,722	110,052	99,974	80,640	101,303	133,486	149,788	1,355,690
After-Savings													
2018S	151,643	121,826	120,396	100,532	89,754	87,615	108,751	98,728	79,464	99,759	131,484	147,466	1,337,419
2019F	153,198	122,965	121,518	101,389	90,468	88,296	109,709	99,528	79,980	100,533	132,673	148,855	1,349,111

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
2008	60,679	56,323	52,557	51,300	52,601	55,870	56,404	52,930	51,191	52,238	56,934	61,945	660,971
2009	60,319	57,143	55,134	52,468	52,802	56,015	57,628	55,929	54,675	55,551	57,688	60,004	675,356
2010	58,527	55,666	53,799	51,561	52,546	56,272	56,380	52,416	51,844	54,570	57,594	58,382	659,556
2011	57,742	59,980	55,524	50,675	51,759	55,477	59,401	55,911	50,918	50,637	53,116	55,779	656,918
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
Before-Savings													
2018S	87,622	79,044	76,816	72,360	74,716	74,649	81,017	81,408	73,905	72,875	79,900	87,648	941,960
2019F	88,949	80,241	77,979	73,456	75,847	75,780	82,243	82,641	75,024	73,978	81,110	88,976	956,224
After-Savings													
2018S	87,502	78,815	76,484	71,934	74,201	74,039	80,299	80,574	72,953	71,797	78,691	86,308	933,598
2019F	87,520	78,754	76,459	71,918	74,289	74,172	80,556	80,854	73,143	71,988	79,008	86,768	935,431

Note: The commercial class is normalized from 2014 to 2017 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2008	95,009	83,999	79,094	66,892	69,677	66,114	71,212	70,951	57,242	70,540	82,793	94,718	908,240
2009	95,727	81,925	76,294	64,159	63,412	59,985	72,433	70,682	64,375	73,304	87,106	98,864	908,266
2010	98,545	83,945	77,442	67,108	59,780	59,833	72,144	70,068	60,545	64,123	82,201	99,603	895,337
2011	100,725	84,225	82,112	65,996	58,766	60,441	68,427	71,106	64,187	70,871	84,304	98,386	909,548
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
Before-Savings													
2018S	64,533	55,274	51,170	42,196	37,981	35,966	47,274	46,124	38,266	43,225	56,552	62,075	580,635
2019F	66,239	56,736	52,524	43,312	38,986	36,917	48,524	47,343	39,278	44,368	58,048	63,716	595,992
After-Savings													
2018S	64,519	55,253	51,142	42,161	37,940	35,918	47,216	46,058	38,192	43,141	56,457	61,970	579,967
2019F	66,125	56,615	52,398	43,184	38,853	36,779	48,376	47,185	39,110	44,188	57,855	63,512	594,181

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2008	19,981	22,004	19,570	18,082	16,331	16,765	16,700	15,303	15,758	18,412	18,815	20,129	217,849
2009	22,496	19,712	19,195	17,101	15,353	13,975	14,634	15,213	17,528	18,602	21,176	20,726	215,710
2010	19,449	17,896	18,991	18,389	18,616	18,603	18,551	20,146	19,259	21,495	22,097	20,207	233,699
2011	23,160	24,129	21,555	17,261	24,902	22,812	25,671	21,690	22,374	24,978	20,262	21,971	270,764
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
Before-Savings													
2018S	34,389	31,391	34,473	32,689	29,362	33,101	30,642	30,159	30,291	30,537	32,267	30,962	380,265
2019F	35,204	32,137	35,227	33,480	29,741	33,874	31,435	30,713	30,873	31,005	33,008	31,676	388,373
After-Savings													
2018S	34,378	31,372	34,446	32,656	29,323	33,055	30,589	30,097	30,220	30,458	32,178	30,864	379,636
2019F	35,075	31,980	35,046	33,277	29,518	33,627	31,160	30,405	30,534	30,631	32,598	31,231	385,084

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2008	1,168	1,104	1,151	1,128	1,111	1,055	1,196	1,094	1,111	1,140	1,083	1,066	13,406
2009	1,097	1,044	1,133	1,024	1,163	1,154	1,112	1,136	1,089	1,153	1,077	1,114	13,297
2010	1,132	1,100	1,172	1,047	1,184	1,513	1,767	1,246	1,123	1,111	1,045	1,041	14,480
2011	1,114	1,027	1,674	582	1,092	1,098	1,086	1,113	1,615	560	1,121	1,153	13,233
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
Before-Savings													
2018S	1,333	1,325	1,344	1,337	1,371	1,357	1,376	1,384	1,290	1,305	1,285	1,373	16,081
2019F	1,333	1,325	1,344	1,337	1,371	1,357	1,376	1,384	1,290	1,305	1,285	1,373	16,081
After-Savings													
2018S	1,320	1,299	1,307	1,289	1,313	1,288	1,294	1,289	1,182	1,182	1,147	1,220	15,131
2019F	1,166	1,146	1,158	1,145	1,174	1,150	1,155	1,147	1,038	1,035	997	1,069	13,380

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2008	672	666	656	1,019	3,441	5,028	8,933	10,984	7,206	4,771	2,190	682	46,248
2009	675	588	673	1,340	3,147	8,501	9,000	9,754	7,548	5,399	1,669	664	48,957
2010	698	605	514	1,217	3,296	4,198	7,243	10,085	6,448	3,223	2,194	660	40,381
2011	654	545	816	908	1,931	3,894	6,737	9,495	8,249	4,369	2,156	590	40,345
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
Before-Savings													
2018S	772	705	1,033	2,248	4,401	6,399	8,277	8,008	5,103	2,904	1,364	735	41,947
2019F	772	705	1,033	2,248	4,401	6,399	8,277	8,008	5,103	2,904	1,364	735	41,947
After-Savings													
2018S	771	704	1,032	2,245	4,393	6,381	8,246	7,969	5,068	2,882	1,353	730	41,773
2019F	769	702	1,029	2,240	4,383	6,360	8,214	7,934	5,042	2,868	1,347	728	41,615

System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2008	660	660	543	535	476	380	502	494	443	504	666	677	707	502
2009	707	643	624	507	481	415	496	446	564	514	660	704	704	496
2010	683	629	536	499	486	420	566	554	448	487	652	726	726	566
2011	722	666	593	516	472	448	529	537	509	508	632	691	702	537
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	717	605
Before-Savings														
2018S	703	633	581	497	446	511	601	596	471	512	629	711	755	608
2019F	714	643	590	505	454	519	611	606	478	521	639	722	766	618
After-Savings														
2018S	703	633	581	497	446	510	600	596	470	512	629	710	754	608
2019F	713	642	589	504	452	517	609	604	477	519	637	720	764	616

3. CUSTOMER FORECAST

3.1 *CUSTOMERS*

Customer Count	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,772	117,748	118,934	120,405
Commercial	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,398	16,110	16,405
Wholesale	7	7	7	7	7	6	6	6	6	6	6	6
Industrial	36	33	35	36	39	47	49	50	50	50	51	51
Lighting	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,511	1,511	1,511
Irrigation	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,080	1,080	1,080
Total Direct	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,793	137,692	139,459

3.2 *CUSTOMER ADDITIONS*

Customer Additions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	1,855	1,063	1,318	912	433	12,634	1,569	735	1,606	1,976	1,186	1,471
Commercial	206	92	111	106	286	1,851	701	613	97	325	712	295
Wholesale	-	-	-	-	-	(1)	-	-	-	-	-	-
Industrial	(2)	(3)	2	1	3	8	2	1	-	-	1	-
Lighting	(82)	(36)	(44)	(27)	(64)	(95)	(24)	(30)	(31)	(48)	-	-
Irrigation	18	18	9	17	(1)	6	6	(8)	(5)	(10)	-	-
Total Direct	1,995	1,134	1,396	1,009	657	14,403	2,254	1,311	1,667	2,243	1,899	1,767

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.30	11.27

5. ENERGY

5.1 NORMALIZED AFTER-SAVINGS ENERGY

Energy (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,337	1,349
Commercial	661	675	660	657	681	788	863	853	905	915	934	935
Wholesale	908	908	895	910	899	675	567	580	574	574	580	594
Industrial	218	216	234	271	291	352	381	380	373	363	380	385
Lighting	13	13	14	13	13	13	16	16	16	16	15	13
Irrigation	46	49	40	40	38	40	40	46	42	42	42	42
Net	3,042	3,100	3,085	3,140	3,151	3,222	3,163	3,174	3,206	3,230	3,288	3,319
Losses	309	316	284	307	271	278	270	272	274	282	282	283
Gross	3,351	3,416	3,369	3,447	3,422	3,500	3,433	3,446	3,480	3,512	3,570	3,602
System Peak (MW)												
Winter Peak	707	704	726	702	723	698	693	685	755	717	754	764
Summer Peak	502	496	566	537	589	600	620	611	593	605	608	616

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE ENERGY

Wholesale (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
BCH Lardeau	7	6	10	8	6	6	6	6	6	8	7	7
BCH Kingsgate	3	4	3	3	5	5	5	5	5	5	5	5
City of Grand Forks	41	41	41	41	41	41	39	41	41	39	47	54
City of Nelson	107	109	90	88	80	83	81	83	80	86	77	80
City of Penticton	346	346	341	344	341	348	342	348	345	338	340	340
District of Summerland	92	78	97	96	95	98	94	97	98	98	104	107
City of Kelowna	312	324	314	329	332	94	-	-	-	-	-	-
City of Princeton	-	-	-	-	-	-	-	-	-	-	-	-
Total	908	908	895	910	899	675	567	580	574	574	580	594

5.3 DSM AND OTHER SAVINGS (GWH) WITHOUT LOSSES[3]

Energy (GWh)	2013	2014	2015	2016	2017	2018S	2019F
Demand Side Management	(28)	(14)	(12)	(11)	(28)	(14)	(39)
Advance Metering	2	3	4	4	5	4	8
Customer Information Portal	-	-	-	-	(2)	(4)	(4)
Residential Conservation Rate	(14)	(14)	(4)	(4)	(4)	-	-
Rate - Driven	-	(5)	(5)	(3)	(3)	(0)	(0)
Total Net	(40)	(30)	(17)	(14)	(32)	(14)	(36)

[3] See Section 3 of the Application for the impact of AMI on losses.

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2012	2013	2014	2015	2016	2017
Actual						
Residential	99,228	98,906	113,431	114,166	115,772	117,748
Commercial	11,811	12,077	14,363	14,976	15,073	15,398
Wholesale	7	6	6	6	6	6
Industrial	39	39	49	50	50	50
Lighting	1,739	1,641	1,620	1,590	1,559	1,511
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080
Total	113,915	113,766	130,572	131,883	133,550	135,793
Forecast						
Residential	101,320	103,279	113,229	114,855	115,758	116,657
Commercial	11,837	12,130	13,739	14,531	15,042	16,122
Wholesale	7	7	6	6	6	6
Industrial	36	36	48	49	49	50
Lighting	1,830	1,830	1,742	1,620	1,620	1,559
Irrigation	1,075	1,075	1,091	1,103	1,103	1,090
Total	116,105	118,357	129,855	132,164	133,578	135,484
Variance (customers)						
Residential	(2,092)	(4,373)	202	(689)	14	1,091
Commercial	(26)	(53)	624	445	31	(724)
Wholesale	-	(1)	-	-	-	-
Industrial	3	3	1	1	1	-
Lighting	(91)	(189)	(122)	(30)	(61)	(48)
Irrigation	16	22	12	(8)	(13)	(10)
Total	(2,190)	(4,591)	717	(281)	(28)	309
Variance (%)						
Residential	-2.1%	-4.4%	0.2%	-0.6%	0.0%	0.9%
Commercial	-0.2%	-0.4%	4.3%	3.0%	0.2%	-4.7%
Wholesale	0.0%	-16.7%	0.0%	0.0%	0.0%	0.0%
Industrial	7.7%	7.7%	2.0%	2.0%	2.0%	0.0%
Lighting	-5.2%	-11.5%	-7.5%	-1.9%	-3.9%	-3.2%
Irrigation	1.5%	2.0%	1.1%	-0.7%	-1.2%	-0.9%
Total	-1.9%	-4.0%	0.5%	-0.2%	0.0%	0.2%

6.2 *LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST*

Energy (GWh)	2012	2013	2014	2015	2016	2017
Normalized						
Residential	1,229	1,353	1,296	1,298	1,296	1,320
Commercial	681	788	863	853	905	915
Wholesale	899	675	567	580	574	574
Industrial	291	352	381	380	373	363
Lighting	13	13	16	16	16	16
Irrigation	38	40	40	46	42	42
Net	3,151	3,222	3,163	3,174	3,206	3,230
Gross	3,422	3,500	3,433	3,446	3,480	3,512
Forecast						
Residential	1,264	1,276	1,402	1,397	1,367	1,290
Commercial	696	709	813	808	871	908
Wholesale	926	935	581	593	579	585
Industrial	250	255	389	371	393	370
Lighting	14	14	13	14	13	16
Irrigation	44	43	42	40	39	41
Net	3,193	3,233	3,240	3,224	3,262	3,210
Gross	3,502	3,543	3,519	3,499	3,540	3,484
Variance (GWh)						
Residential	(35)	77	(106)	(99)	(71)	30
Commercial	(16)	79	50	45	34	7
Wholesale	(27)	(260)	(14)	(13)	(5)	(11)
Industrial	41	97	(9)	9	(20)	(7)
Lighting	(0)	(0)	3	2	3	(0)
Irrigation	(6)	(3)	(2)	6	3	1
Net	(43)	(11)	(77)	(50)	(56)	20
Gross	(81)	(43)	(86)	(53)	(59)	28
Variance (%)						
Residential	-2.9%	5.7%	-8.2%	-7.6%	-5.5%	2.3%
Commercial	-2.3%	10.1%	5.9%	5.3%	3.8%	0.8%
Wholesale	-3.0%	-38.5%	-2.5%	-2.2%	-0.8%	-1.9%
Industrial	14.1%	27.6%	-2.2%	2.3%	-5.3%	-2.0%
Lighting	-3.5%	-1.5%	18.2%	12.7%	16.3%	-0.4%
Irrigation	-14.9%	-8.7%	-4.9%	12.1%	7.7%	2.2%
Net	-1.4%	-0.3%	-2.4%	-1.6%	-1.7%	0.6%
Gross	-2.4%	-1.2%	-2.5%	-1.5%	-1.7%	0.8%

Note: The 2013 forecast included the CoK as wholesale customer since at the time of the 2012-2013 Revenue Requirements the application for the acquisition of the CoK was not yet filed.

6.3 *NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH*

Normalized Actual and Forecast								
Energy (GWh)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,337	1,349
Commercial	681	788	863	853	905	915	934	935
Wholesale	899	675	567	580	574	574	580	594
Industrial	291	352	381	380	373	363	380	385
Lighting	13	13	16	16	16	16	15	13
Irrigation	38	40	40	46	42	42	42	42
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,288	3,319
Losses	271	278	270	272	274	282	283	283
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,570	3,602
System Peak								
Winter Peak (MW)	723	698	693	685	755	717	754	764
Summer Peak (MW)	589	600	620	611	593	605	608	616

Growth Year over Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**
Residential		10%	-4%	0%	0%	2%	1%	1%
Commercial		16%	9%	-1%	6%	1%	2%	0%
Wholesale		-25%	-16%	2%	-1%	0%	1%	2%
Industrial		21%	8%	0%	-2%	-3%	5%	1%
Lighting		0%	16%	2%	0%	0%	-5%	-12%
Irrigation		4%	1%	15%	-9%	0%	0%	0%
Net		2%	-2%	0%	1%	1%	2%	1%
Losses		3%	-3%	1%	0%	3%	0%	0%
Gross		2%	-2%	0%	1%	1%	2%	1%
System Peak								
Winter Peak (MW)		-3%	-1%	-1%	10%	-5%	5%	1%
Summer Peak (MW)		2%	3%	-1%	-3%	2%	0%	1%

Customer Count	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**
Residential	99,228	111,862	113,431	114,166	115,772	117,748	118,934	120,405
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	16,110	16,405
Wholesale	7	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	50	50
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,511	1,511
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,080	1,080
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	137,691	139,457

Growth Year over Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**
Residential		13%	1%	1%	1%	2%	1%	1%
Commercial		16%	5%	4%	1%	2%	5%	2%
Wholesale		-14%	0%	0%	0%	0%	0%	0%
Industrial		21%	4%	2%	0%	0%	0%	0%
Lighting		-5%	-1%	-2%	-2%	-3%	0%	0%
Irrigation		1%	1%	-1%	0%	-1%	0%	0%
Total Direct		13%	2%	1%	1%	2%	1%	1%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2015	2016	2017
After- Savings Normalized Actual UPC	11.41	11.27	11.31
Forecast	12.24	11.89	11.71
Variance	(0.83)	(0.62)	(0.40)
Variance (%)	-7.3%	-5.5%	-3.5%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2015	2016	2017
After- Savings Actual Peak	693	724	755
Forecast	749	760	734
Variance	(56)	(36)	21
Variance (%)	-8%	-5%	3%

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross energy, peak load and load factor. The annual load factor is calculated as annual energy ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2012	3,421,657	723	0.54
2013	3,525,953	720	0.56
2014	3,433,619	651	0.60
2015	3,446,152	693	0.57
2016	3,480,006	724	0.55
2017	3,512,293	755	0.53
2018S	3,560,786	751	0.54
2019F	3,592,222	761	0.54

Appendix A-3

Load Forecast Methods

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1. LOAD FORECAST METHODS

In this appendix, FBC provides a detailed description of its demand forecast method.

In the figures provided the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2019 Annual Review the latest calendar year for which full actual data exists is the 2017.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2019 is the Forecast Year (2019F).
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous year's revenue requirements. For example, for this Application the Seed Year is 2018 (2018S) and the Seed Year forecast is based on the latest actual years, including 2017.

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, energy requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation. Industrial and street lighting loads are typically insensitive to the weather. Currently the residential, wholesale and commercial load classes are normalized because the associated regression results showed high R^2 values for these load classes. The commercial class data is normalized from 2014 to 2017 since a correlation presented itself in those years so far, therefore all data prior to 2014 is actuals data and not normalized since it did not show a correlation to weather at that point in time.

Results of the normalized regressions are provided in the tables below.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	40,403	62,305	70,639	64,997
Slope HDD	169	126	-	96
Slope CDD	-	-	213	-
Adjusted R^2	0.75	0.78	0.86	0.91

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	49,897	54,234	59,830	59,263
Slope HDD	80	55	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.97	0.96	0.93	0.96

Table A3-2: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	42,182	52,591	52,730	53,621
Slope HDD	31	3	-	(3)
Slope CDD	-	-	41	-
Adjusted R^2	0.79	0.85	0.85	0.81

Table A3-2: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	2,401	-	-	7,110
Slope HDD	(3)	(10)	-	(11)
Slope CDD	-	-	25	-
Adjusted R^2	0.14	0.86	0.58	0.40

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[2] and Cooling Degree Days (CDD)[3] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential and wholesale classes, regress energy on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). All monthly energy and degree day data for each season is used and four separate regressions are

[2] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[3] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

calculated for each class. The City of Kelowna (CoK) Event variable was included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2017:
   (a) obtain the month's HDD (or CDD) information from Environment Canada;
   (b) calculate the deviation from the 10-year average (2008-2017) HDD (CDD) as found in Step 2;
   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and
   (d) add the normalization adder to the month's load (residential, wholesale or commercial).

The general equation to normalize energy requirements in month m is shown below.

$$Normalized\ Energy_m = Energy_m - HDD\ Slope_t \times (HDD_m - Normal\ HDD_m)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Energy_m = Energy_m - CDD\ Slope_t \times (CDD_m - Normal\ CDD_m)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *ENERGY FORECAST*

This section discusses the before-savings forecast energy requirements for different load classes. Savings is defined as the sum of DSM, the Customer Information Portal (CIP), Advanced Metering Infrastructure Project (AMI), and rate-driven impacts. Note that the CIP forecast is only available for the residential class. A general formula for an after-savings load in year *t* is:

$$After\ Savings\ Load_t = Before\ Savings\ Load_t - Savings_t$$

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

The before-savings UPC forecast was based on a three year average of historic annual UPC values from 2015 to 2017. FBC reviews the forecast methods on an annual basis and found that there was no trend in the most recent three years of UPC data and therefore applied a three year

average. FBC uses the most recent UPC data since the UPC can be influenced by technology and customer behaviour patterns that are changing on an ongoing basis.

Table A3-3: Results of UPC Trend Analysis

Regression	UPC
Start Year	2015
End Year	2017
R^2	0.00
Adjusted R^2	-1.00
df	2
Intercept	4
Slope UPC	0.00

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = 0.5 \times (Year\ End\ Count_{t-1} + Year\ End\ Count_t)$$

The year-end customer count in year (*t-1)* is the prior year actual:

$$Year\ End\ Customer\ Count_{t-1} = Prior\ Year\ Actual$$

The year-end customer count in year *t* is based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population forecast supplied by BC Stats that is customized to the Company's direct service area.

Table A3-4: Results of Residential Regression

Regression	Residential
Start Year	2013
End Year	2017
R^2	0.98
Adjusted R^2	0.98
df	4
Intercept	(10,413)
Slope Population	0.51

1.2.2 Commercial

The expected before-savings commercial load in year *t* was forecast based on the provincial GDP supplied by the CBOC[4]. The relationship is estimated from the following equation.

$$Before\ Savings\ Load_t = b_0 + b_1 \times GDP_t + b_2 \times Princeton\ Event_t + b_3 \times CoK\ Event_t$$

Princeton $Event_t$ is a binary variable for the Princeton Light and Power (PLP) integration event in 2007, CoK_t is a binary variable for the City of Kelowna integration event in 2013 and coefficients b0, b1, b2, and b3 are obtained from an ordinary least squares (OLS) regression analysis on the 2003 to 2017 data.

Table A3-5: Results of Commercial Regression

Regression	GEN
Start Year	2003
End Year	2017
R^2	0.99
Adjusted R^2	0.98
df	14
Intercept	(4,066)
Slope GDP	4.10
Slope PLP Event	38,787
Slope CoK Event	119,625

1.2.3 Wholesale

The Company forecasts its wholesale load based on load surveys from all wholesale customers. For the 2019 forecast load, the response rate was 100 percent. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated energy requirements, etc.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. The majority of the FBC industrial customers responded to the surveys (86 percent of customers accounting for 88 percent of 2019 forecast load).

Consistent with past practice, FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. The lead time for new industrial customers is much longer than the lead time for the typical residential and commercial

[4] The CBOC GDP forecast is included in Appendix A-1.

customer, and FBC staff work with industrial customers well in advance of the date they are added to the system. Given the significant impact and variability in demand from individual customers in the industrial load class, the industrial addition forecast cannot be reliably undertaken through a forecasting process based on historical additions.

1.2.5 Irrigation

Consistent with past practice FBC checks for trends in the historic load data. FBC tested 5, 10 and 15 years of historic data but no statistically significant trend was found for this class. Therefore, an average of the most recent five-year period was used to forecast load. The before-savings irrigation load for 2019F was developed using a 5-year average of actual loads in 2013-2017.

1.2.6 Lighting

Consistent with past practice FBC checks for trends in the historic load data. There is a statistically significant trend for the most recent five-year period which was used to forecast load for this class. The before-savings street lighting forecast for 2019F was based on a trend analysis of lighting loads from 2013 to 2017.

Table A3-6: Results of Lighting Trend Analysis

Regression	UPC
Start Year	2013
End Year	2017
R^2	1.00
Adjusted R^2	0.99
df	4
Intercept	(174,942)
Slope UPC	93.60
Slope CoK Event	2,134

1.2.7 DSM and Other Savings

FBC forecasts load reductions resulting primarily from its DSM programs. In addition to DSM programs the Company also has or anticipates other savings from the AMI, CIP, and the impact of future rate increases. Each of these items is discussed below.

- The forecast of DSM savings is consistent with the Company's 2018 DSM Expenditure Schedule, which was approved by Order G-113-18. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

- AMI savings are the incremental sales that occur due to an increase in paying marijuana grow operations that are offset by loss reductions due to closing illegal marijuana grow sites. The estimates and forecasts of incremental savings are based on the theft reduction information provided as part of the AMI CPCN Application as adjusted by the Commission determination provided in Order C-7-13.

- CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customers to view historic billing and consumption data. The savings estimate is based on a study commissioned by FBC and on BC Hydro estimates provided in its Smart Meter Initiative business case.

- Rate-Driven impacts are price elasticity savings given as a percentage of the before-savings loads. The current price elasticity estimate of -0.05 is consistent with BC Hydro's estimate.

The CIP is forecast for the residential class only while AMI is forecast for the residential and loss classes. CIP and rate-driven impacts are calculated as a percentage of the corresponding before-savings load. The rate-driven impact savings are applied to all rate classes. Savings from the 2012 implementation of the Residential Conservation Rate (RCR) are assumed to be fully realized; therefore no incremental savings have been forecast.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the ten year average (2008-2017) of historic peak data. The historic peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-Generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-139-14 – FBC MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	80	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	Consultation with stakeholders on the study's terms of reference and the choice of consultant has been completed. The study is currently in progress and will be filed later in 2018, after a workshop (to be scheduled) with stakeholders to review the results of the study.	N/A
2.	212	98	***Accounting Changes*** The Panel directs FBC to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.	Ongoing during term of PBR	Section 12.3
G-169-14 – FBC ADVANCED METERING INFRASTRUCTURE (AMI) ENABLED BILLING OPTIONS FOR CUSTOMERS					
3.	6	3	***AMI Deferral Account*** FBC must flow through any incremental O&M costs and/or benefits to customers as part of the Advanced Metering Infrastructure project deferral account.	Ongoing during term of PBR. Incremental costs/benefits are included in the Flow-through deferral account	Sections 6.3.3 and 12.4.2.5
4.	6	4	FBC must flow through any incremental working capital benefits to customers as part of the new flow through deferral account, approved in Order G-163-14, or another appropriate flow through account.	Ongoing	Sections 7.8.1 and 12.4.2.5
5.	n/a	5	FBC must report these incremental costs and savings in each of the annual reviews during the Performance Based Ratemaking term.	Ongoing during term of PBR	Section 6.3.3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
6.	15	n/a	***Advanced Metering Infrastructure (AMI) Theft Reduction*** The Commission Panel directs FBC to include, in its next and subsequent annual PBR reports, the impact of AMI on losses through theft deterrence. This directive will improve regulatory efficiency in the review of FBC's proposed actions (and FBC's incentives to undertake these actions while under PBR) related to the reduction of theft related costs. The information to be submitted should include: (i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and (ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.	Ongoing during term of PBR	Section 3.5.7.1
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
7.	17	4	***Capital Expenditures Exceeding the Deadband*** Should the dead-band for annual capital expenditures approved in the PBR Plans be exceeded FBC or FEI are directed to include in its next Annual Review filing, recommendations as to any adjustment to base capital (re-basing) for Commission approval.	Completed	Section 1.4.3
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES					
8.	15	5	***Ruckles Substation Rebuild Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the Ruckles Substation Rebuild project: • The status of the Ruckles project, including a comparison of the project timeline provided in the current Application to the updated project timeline, as at the time of filing each annual review application. • Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application. • The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the Application, with explanations for any variances.	Ongoing during term of PBR	Section 7.3 and Appendix D

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
9.	21	6	***Upper Bonnington Old Units Refurbishment Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Ongoing during term of PBR	Section 7.3 and Appendix C
G-153-17 – FBC CASTLEGAR DISTRICT OFFICE DISPOSITION					
10.		4	***Castlegar Office Disposition deferral account:*** FortisBC is directed to proposed the disposition of the Castlegar Office Disposition deferral account in the annual review of 2019 rates filing.	Amortization proposed in 2019	Section 12.4.2.4
G-9-18 – FBC APPLICATION FOR APPROVAL OF RATE DESIGN AND RATES FOR ELECTRIC VEHICLE DIRECT CURRENT FAST CHARGING SERVICE					
11.	2	2	***Electric Vehicle DCFC stations*** FBC is directed to separately track and account for all costs associated with the EV DCFC stations and exclude all such costs from its utility rate base until the Commission directs otherwise.	EV DCFC Stations costs excluded from rate base until otherwise directed	Section 11, Schedule 2
G-38-18 – FBC ANNUAL REVIEW FOR 2018 RATES					
12.	14	7	***Capital spending in excess of the dead band*** FBC is directed to provide the following information related to capital in its annual review of 2019 rates application: 1. A breakdown and explanation for both the annual variances (2014–2018) and cumulative variances between forecast/actual and formula capital	Completed	Appendix B2

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
			which quantifies the variances attributable to the following factors: • System improvements to accommodate customer growth; • Customer driven modifications at RG Anderson Terminal; • Increased costs due to unfavourable exchange rate; • A list of work prioritized from previous years by project, including the capital cost and the previously scheduled dates and classifications (i.e. mandatory, essential or flexible); • New projects in generation to address compliance with new WorkSafeBC legislation; • Unanticipated transmission projects to address safety and reliability issues; • Additional substation projects to address end-of-life equipment replacements; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its capital expenditures during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the PBR term. 3. A list of projects that were originally planned to be completed during the PBR term that are now expected to be delayed until after the PBR term, including a description of the project, reason for the delay, the estimated capital cost, classification and the year for which it was originally planned.		
15.	18	9	***Residential Use Per Customer*** The Panel does consider it appropriate to continue to monitor this trend and directs FBC to submit a table with the prior year forecast versus actual normalized after-savings residential UPC for the most recent three years in the next annual review filing.	Completed	Appendix A2
16.	19	10	***After Savings Winter Peak*** The Panel…directs FBC to provide a table with the prior year forecast versus actual after-savings winter peaks for the most recent three years in the next annual review filing.	Completed	Appendix A2

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-131-18 – FBC ANNUAL REVIEW FOR 2018 RATES COMPLIANCE FILING AND REQUEST FOR PERMANENT RATES					
17.	-	2	***2018 Revenue Deficiency Deferral Account*** FBC is approved to establish the 2018 Revenue Deficiency deferral account as a non-rate base deferral account financed at FBC's short-term interest rate, to record the forecast $0.896 million revenue deficiency, the disposition of which will be addressed in FBC's Annual Review for 2019 Rates.	Amortization period will be proposed in a future application	Section 12.4.2.1

1. INTRODUCTION

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

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

Table 1-3 at page 4 of the Application shows the annual and cumulative variances between actual/forecast and formula capital expenditures. In this Appendix, FBC provides the requested information for each of the remaining areas described in Order G-38-18.

2. ANNUAL CAPITAL VARIANCES

In Table B2-1 below, FBC provides a breakdown and itemization of variances attributable to the items identified by the Commission.

Table B2-1: Annual Capital Variances ($ millions)

Line No.	Description	2014	2015	2016	2017	2018F	Cumulative
1	Growth factor reduction for net customer additions	0.140	0.080	0.260	0.220	0.290	0.980
2	X factor increase by 0.53 percent	0.230	0.230	0.230	0.240	0.250	1.170
3	System improvements to accomodate growth	2.000	2.000	1.000	2.600	1.000	8.600
4	Forced relocation of Highway 97 infrastructure	0.100	0.400	2.400	0.700	0.100	3.700
5	Customer-driven modifications at RG Anderson Terminal			0.100	2.700	0.735	3.535
6	New Generation projects to address compliance with WorkSafeBC legislation (guarding of rotating parts and floor covers)			0.140	0.140	0.584	0.864
7	New Generation projects to address compliance with WorkSafeBC legislation (single device isolation)					0.254	0.254
8	Unanticipated transmission projects to address safety and reliability issues					0.600	0.600
9	Substation projects to address end of life equipment replacements				1.200	0.600	1.800
10	Other contributing factors:						
11	Weather events					1.899	1.899
12	Evolved project definition				1.900		1.900
13	Project re-prioritization				4.000	0.800	4.800
14	Cyber security				0.125	0.215	0.340
15	**TOTAL Capital Pressures**	2.470	2.710	4.130	13.825	7.327	30.442
16	**Annual and cumulative capital expenditures variance compared to formula**	0.472	2.408	2.964	15.799	11.394	33.035

Table B2-1 shows that the pressures experienced in years 2014 to 2016 are greater than the variances of FBC's annual capital expenditures over formula in those years. In order to manage pressures experienced during years 2014 to 2016 of the PBR term, some projects that were assessed as being less critical to the system, or that were temporarily less time-sensitive, were reprioritized to future years to accommodate the required projects listed in the table. In 2017 and 2018, FBC has prioritized:

- additional capital expenditures to start to catch up on an accumulation of work that had been re-prioritized from previous years of the PBR term; and
- new projects that were identified to address safety, compliance, reliability issues and to replace end of life of equipment.

For this reason, FBC's cumulative capital expenditure compared to formula is higher than the total of the items shown in Table B2-1.

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

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

FBC provides below a further discussion of each of the items in the table above, other than the formula-related items which are self-explanatory.

2.1 *SYSTEM IMPROVEMENTS TO ACCOMMODATE CUSTOMER GROWTH*

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

2.2 *FORCED RELOCATION OF HIGHWAY 97 INFRASTRUCTURE*

The project was required due to the widening of Highway 97 between Hwy 33 and Sexsmith Road in Kelowna. The Ministry of Transportation and Infrastructure directed FBC to relocate the transmission and distribution infrastructure.

This project is also customer-funded and offset by CIAC, which is excluded from the capital expenditure formula envelope.

2.3 *CUSTOMER DRIVEN MODIFICATIONS AT RG ANDERSON TERMINAL*

The project involves the addition of a 24/32/40 MVA 69/13 kV power transformer to an existing outdoor substation, one 3 MVA 13/8 kV step-down transformer and two main distribution structures with associated MV feeder equipment for both FBC RG Anderson Terminal (one 8 kV feeder) and the adjacent City of Penticton Carmi substation (six 13 kV feeders). RG Anderson Terminal is owned and operated by FBC and Carmi Substation is owned and operated by the City of Penticton.

This project is customer-funded and therefore offset by Contributions in Aid of Construction (CIAC). The project creates a formula capital pressure because CIAC is excluded from the capital expenditure formula envelope under FBC's PBR Plan.

2.4 NEW GENERATION PROJECTS TO ADDRESS COMPLIANCE WITH WORKSAFE BC LEGISLATION

Generation pressures in 2018 were due primarily to Occupational Health and Safety (OHS) requirements under WorkSafe BC legislation[1] including:

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

2.5 UNANTICIPATED TRANSMISSION PROJECTS TO ADDRESS SAFETY AND RELIABILITY ISSUES

There were two unanticipated transmission projects in the Crawford Bay area required to address safety and reliability concerns including:

- Salvaging of 8 kilometres of the old 30L transmission line south of the Crawford Bay substation to Gray Creek due to transfer of this load to more reliable facilities.
- 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.

2.6 SUBSTATION PROJECTS TO ADDRESS END OF LIFE EQUIPMENT REPLACEMENTS

The replacement of Lee Terminal T4 transformer Load Tap Changer was required in order to extend the life of the transformer.

Work required in Generating station switchyards in 2018 such as the Upper Bonnington 28-1 structure and switch replacement, concrete structure remedial work at Upper Bonnington, touch voltage mitigation at Corra Linn, replacement of the bus wood beams at Upper Bonnington, and oil inhibitor treatment for the Lower Bonnington generating unit transformers.

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

2.7 *OTHER CONTRIBUTING FACTORS*

In addition to the PBR formula pressures discussed in Section 1.4 of the Application, FBC has identified the following other contributing factors.

2.7.1 Weather Events

In 2018 to date there have been significant weather related events necessitating urgent repairs which have placed increasing pressure on the sustainment capital budget. The weather events include snowstorms in the Kootenay region, flooding and associated landslides throughout the territory as well as windstorms. Weather events are unpredictable and FBC strives to maintain service and to restore power as soon as possible during these weather related events.

2.7.1 Evolved Project Definition

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

2.7.2 Project Re-prioritization

The following is a list of work prioritized from previous years into 2017, including the priority (as set out in Section 3.1 below) assigned to each item:

- Distribution Rehabilitation scope for three distribution feeders in the Kootenay and Boundary regions (Essential). These projects were deferred from 2016 to 2017 due to capital cost pressures. The 2017 cost was $0.350 million.
- Condition Assessment and Rehabilitation for 38 Line (Kootenay Lake Crossing span) (Essential). This project was deferred from 2015 due to capital cost pressures. The 2017 cost was $0.350 million.
- Transmission Rehabilitation scope for the following lines: 27 Line, 72 Line, 74 Line, 32 Line, 19 Line, 75 Line, 55 Line (Essential). These projects were deferred from 2016 to 2017 due to capital cost pressures. The 2017 cost was $0.125 million.
- Distribution Line Rebuilds scope for portions of two distribution feeders in the Kootenay and South Okanagan regions (Essential). These projects were deferred from 2015 due to capital cost pressures. The 2017 cost was $0.050 million.
- Distribution Line Rebuild scope for portion of a distribution feeder in Creston (Midgely Mountain) (Essential). This project was deferred from 2016 due to capital cost pressures. The 2017 cost was $0.137 million.

- Underground Cable Replacement scope for a distribution feeder in Kelowna (Essential). This project was deferred from 2014 due to capital cost pressures. The 2017 cost was $0.015 million.
- Glenmore Feeder 5 (Summit Drive) Capacity Upgrade (Essential). This project was deferred from 2015 due to capital cost pressures. The 2017 cost was $0.295 million.
- Installation of oil containment at the Keremeos substation (Essential). This project was deferred from 2015 due to capital cost pressures. The 2017 cost was $0.230 million.
- Replacement of four bulk oil circuit breakers at three distribution substations (Essential). This project was deferred from 2016 due to capital cost pressures. The 2017 cost was $0.700 million.
- Princeton Roof Replacement (Mandatory). This project was deferred from 2015 to 2017 due to capital cost pressures. Repairs were completed on the roof to temporarily extend the life. The 2017 cost was $0.160.
- Rooftop HVAC Replacement for non-compliant refrigerant (Mandatory). This multi-year project was deferred from starting in 2015 to 2016 due to capital cost pressures. The 2017 cost was $0.758 million.
- Vehicle replacement projects were deferred from 2014 through 2016 due to capital budget pressures. The 2017 cost was $0.200 million.
- SAP Integration (Project One) was deferred from 2016 to 2017 due to critical resource availability and added project scope. The 2017 cost was $0.321 million and $0.591 million forecast in 2018.

In 2018, the following work was reprioritized from 2017:

- Distribution Rehabilitation scope for four distribution feeders in the Kootenay region (Essential). These projects were deferred from 2017 to 2018 due to capital cost pressures. The 2018 forecast cost is approximately $0.4 million to complete.
- Underground Switcher Replacement scope for a distribution feeder in Kelowna (Essential). This project was deferred from 2017 due to capital cost pressures. The 2018 forecast cost is $0.150 million to complete.
- Underground Cable Replacement scope for a distribution feeder in Kelowna (Essential). This project was deferred from 2017 due to capital cost pressures. The 2018 forecast cost is $0.050 million to complete.
- Station Smart Devices scope for a station transformer protection in South Okanagan (Essential). This project was deferred from 2017 due to capital cost pressures. The 2018 forecast cost is $0.165 million to complete.

2.7.3 Cyber Security

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

2.7.4 Exchange Rates

FBC's Base Capital forecast was based on an expectation that the CAD/USD exchange rate would be close to par[3], whereas capital expenditures during the PBR term have been incurred at an average annual rate exchange rate closer to 0.8[4]. FBC's Base Capital for the PBR plan was set at FBC's 2013 Approved levels. FBC's 2013 Approved capital expenditures were based on a CAD/USD exchange rate forecast of 0.97. Over the course of the PBR term, the Base Capital is escalated using the formula described in section 7.2.1 of the Application. A CAD/USD exchange rate forecast is not part of the formula. This causes capital cost pressures as many of FBC's major equipment purchases are from outside Canada and are denominated in USD currency.

As of June 2018, FBC's CAD/USD exchange rate forecast for 2018 was 0.78.

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

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[2] FBC Annual Review for 2018 Rates, page 4.

[3] The forecast of CAD/USD Exchange Rates was provided in Appendix E1 of the Evidentiary Update to the PBR Application (a 2019 exchange rate is not included in the table below because the initial PBR application was from 2014 to 2018 (2014: 0.99, 2015: 1.01, 2016: 0.99, 2017: 0.96, 2018: 0.95).

[4] 0.8 is the average 2014 through 2018 Bank of Canada annual average daily closing CAD/USD exchange rate per the bank of Canada website. 2018 is based on average available rates up to June 30, 2018. (2014: 0.91, 2015: 0.78, 2016: 0.76, 2017: 0.77, 2018: 0.78).

3. CAPITAL PRIORITIZATION

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

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

FBC recognizes the need for continual improvement in prioritizing investments and for more transparency in ensuring that all investments create value for the customer. As such, FBC continues to align processes across the organization in its capital planning to help achieve the highest level of benefit for the available funds and resources. FBC provides below a description of its current capital expenditure prioritization processes and the planned improvements to those processes over the remainder of the PBR term.

3.1 *CURRENT CAPITAL PRIORITIZATION PROCESS*

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

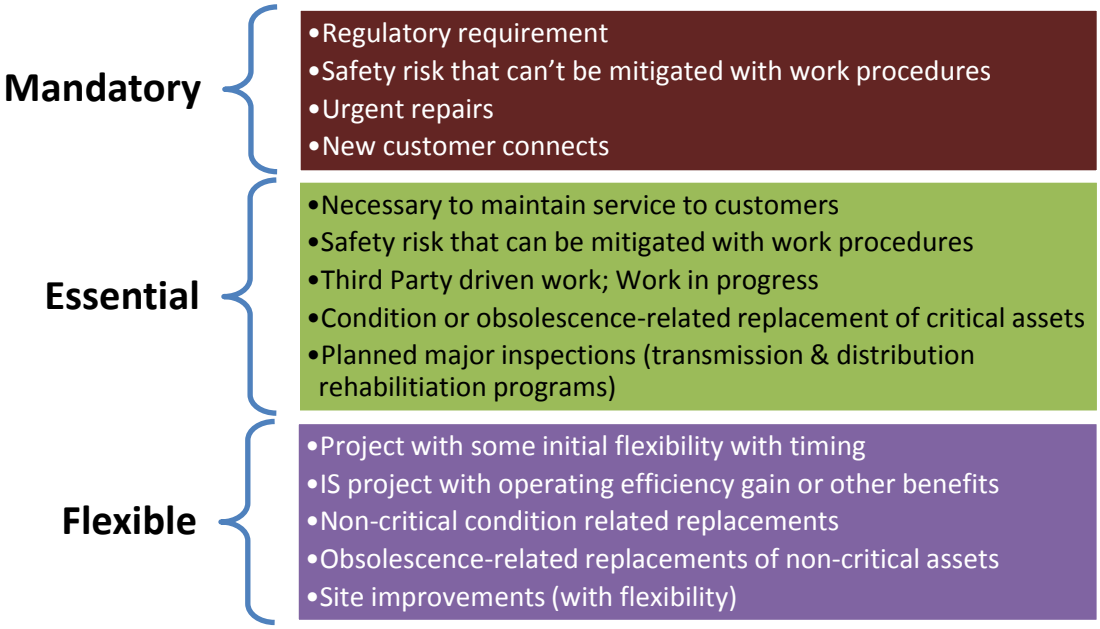
To date during the current PBR term, capital expenditures, including new projects required to address safety, compliance, reliability issues and to replace end of life of equipment, but excluding non-discretionary growth capital, have been prioritized through the following steps:

Step 1: Within the various planning groups of electric assets sustainment and general plant (e.g. Information Systems (IS), Fleet and Facilities), capital investments are prioritized through established asset-specific means. Criteria such as asset health/condition, number of customers served, location, reliability indices, and operating cost opportunities are considered through a project portfolio management process that strives to quantify the benefit of the proposed projects. IS projects are prioritized through the Project Portfolio Management process that quantifies the benefit of the proposed projects[5].

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

Step 2: In addition to this asset specific prioritization, during the development of the 2016 capital plan, FBC began assigning each project to one of the three classifications in Figure B3-1 below

Figure B3-1: Capital Priority Classification



Step 3: Based on the three classifications set out in Figure B3-1, available funds and resources were allocated towards mandatory and essential work first. As funds were anticipated to be insufficient to cover the proposed scope of flexible work, further analysis was completed as described in Step 4.

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

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

3.2 *PLANNED IMPROVEMENTS TO THE CAPITAL PRIORITIZATION PROCESS*

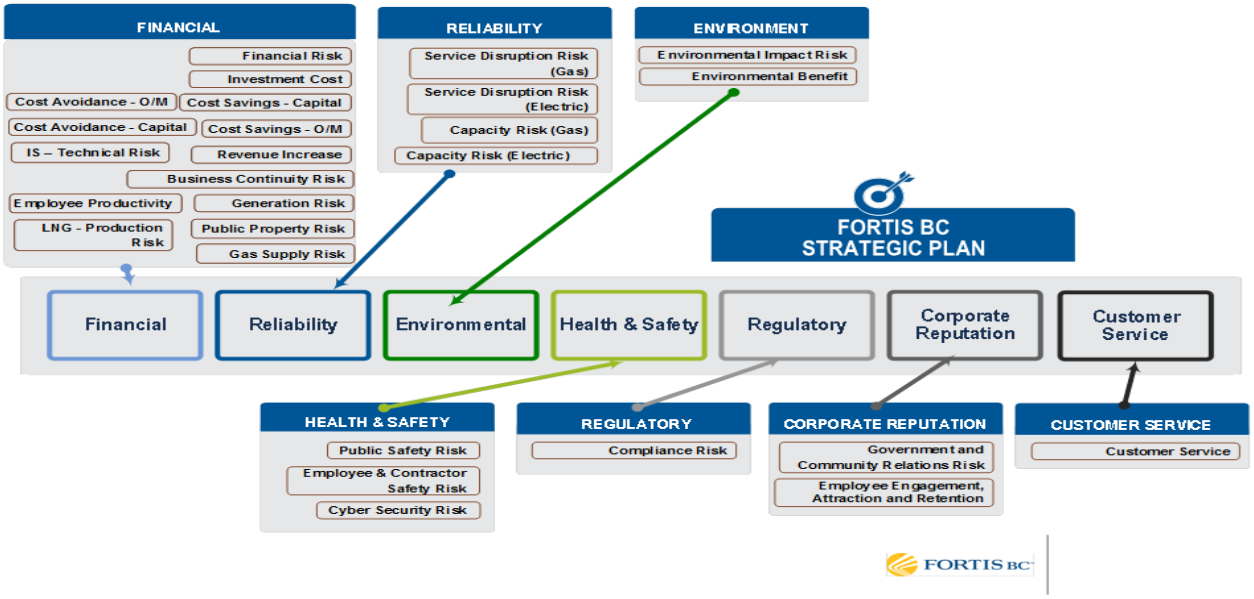
In recognition of the importance of consistently valuing and prioritizing its investments, and in light of recent capital pressures that are expected to continue, FBC is pursuing opportunities to build on and enhance its capital planning process to further align capital investment decision-making across the Company and leverage the tools, processes and systems implemented to date.

To this end, in 2018 FBC is implementing an Asset Investment Planning (AIP) tool[6]. Over time, the AIP will allow the consistent quantification of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

The foundation of the AIP tool is the value framework that is used to quantify the value of potential investments. The value framework is made up of seven overarching values that were derived from FBC's strategic objectives and core values. They are: financial, reliability, environmental, health & safety, regulatory, corporate reputation and customer service. Under each value, there are measures which contribute and impact each value. These measures, and which value they impact, are shown below in Figure B3-2.

Each project is evaluated against one or more of the measures that will be impacted by undertaking the project. The measures can be calculated automatically using asset and investment data or through user responses to predefined questions or a combination of both.

Figure B3-2: Preliminary Value Measures for Asset Investment Planning Tool



Once projects are evaluated using the value framework, the tool provides the ability to conduct an automated optimization of the capital planning portfolio for a given period of time to achieve the greatest benefit within a set of user-defined financial and/or resource constraints. Multiple scenarios can be generated using differing constraints to evaluate alternate execution strategies. The tool also supports approval workflows at the project and portfolio levels to ensure appropriate levels of senior management review.

[6] Implementation of the AIP tool has been a multi-phase project with Phase 1 applying to the gas system assets of FEI. The Phase 2 scope covers FEI and FBC General plant and FBC Electric asset management.

Once fully implemented, the AIP tool will provide the following benefits:

- Increased ability to make risk-informed decisions in capital planning by valuing investments through a common value framework;
- Ability to show consistent methodology across asset classes in valuing capital projects;
- Increased transparency and ability to communicate the value being achieved through execution of the capital plan; and
- Improved ability to optimize the portfolio over multiple years and to consider alternative constraint scenarios.

3.3 *PROJECTS PLANNED TO BE UNDERTAKEN OUTSIDE OF PBR TERM*

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

The following is a list of the projects that FBC had identified for execution in the 2014-2018 PBR Application and have delayed beyond the PBR term.

Table B3-1: Projects Delayed to Beyond the PBR Term

Name-Description	Estimated Cost (million)	Original Schedule	Current Status
Glenmore Low Voltage Bus Capacity Upgrade Upgrade the 1200 amp rated low voltage bus and three bus tie switches at Glenmore substation to a 2000 amp rating.	$ 0.2	2017	Delayed indefinitely due to redistribution of load
The Summerland Substation transformer: Required to supply the District of Summerland municipal utility with a distribution wholesale supply. The load on the existing Summerland T1 transformer was forecast to exceed 95 percent of the contract Demand Limit in 2015. Under the terms of the wholesale supply agreement, FBC would be required to upgrade the supply capacity in order to continue to provide reliable service.	$7.0	2015	Will be reviewed in the near future due to lower load growth than previously forecast.
Grand Forks Terminal Feeder Addition Additional feeder to supply Christina Lake from Grand Forks Terminal station	$5.0	2016-2017	Planned for 2024. Delayed due to dependency on the Grand Forks Terminal project being completed.

Name-Description	Estimated Cost (million)	Original Schedule	Current Status
DG Bell 4 Feeder Addition Currently the DG Bell substation has three feeders with a spare breaker available for a future feeder. The original planned solution was to make use of the spare breaker and add a fourth feeder to the station in order to offload the existing load	$1.8	2018	Planned for 2020. Delayed to coordinate with a City of Kelowna project.
Okanagan Long Term Solution Procurement of land to construct a FBC Facility in Kelowna	$12.0	2016	Delayed due to land procurement challenges.

As described in the PBR Application[7], FBC developed a forecast of Information Systems expenditures for the PBR period to allow for the implementation of projects to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. Information Systems expenditures are categorized under five main areas of focus including infrastructure sustainment, desktop infrastructure sustainment, application sustainment, business technology transformation and business technology enhancements. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. FBC does not have any IS projects that have been deferred to outside the PBR term.

3.4 *SUMMARY*

FBC has taken a number of steps over the years to enhance and strengthen its internal capital prioritization processes. FBC is implementing an Asset Investment Planning (AIP) tool Q4, 2018. The AIP tool will allow the consistent quantification and evaluation of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

[7] Table C4-22, Section 4.6.4 of the PBR Application.

Appendix C

UPPER BONNINGTON REFURBISHMENT PROJECT STATUS REPORT

Appendix C

FortisBC Inc.

Upper Bonnington Unit Refurbishment Project

Status Report

August 2018

1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the Commission approved capital expenditures related to the Upper Bonnington Old Units Refurbishment (UBO Refurbishment Project) in Order G-8-17. The Commission directed FBC to provide the following information about the progress of the project as part of its annual review applications:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to any updated project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project 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.

FBC submits the following report regarding the UBO Refurbishment Project in compliance with Directive 6 of Commission Order G-8-17, including costs to June 30, 2018.

1.2 *GENERAL PROJECT STATUS*

As described in the Annual Review for 2018 Rates Application, the UBO Refurbishment Project commenced on schedule with the dismantling of Unit 3 in late June 2017. FBC completed the electrical refurbishment over the next several months and the unit was successfully returned to service in Q4 2017.

[1] G-8-17, Appendix A, page 21.

The dismantling of Unit 4 began in February 2018. FBC advanced a portion of the planned engineering and procurement work from 2018 to 2017 to support the early 2018 construction. This proactive approach allowed FBC to secure machining and fabrication resources in advance of the Unit 4 dismantling thus preventing any unnecessary delays. Based on the condition of the Unit 4 components, FBC does not anticipate any significant delays to the project and anticipates returning Unit 4 to service in Q4 2018.

The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). Project expenditures to June 30, 2018 are approximately $13.797 million. Final project costs are currently forecast to be on budget.

In terms of engineering, the technical and performance specifications have been completed for all units (as these specifications are common to all four units). Electrical and mechanical designs have largely been completed and now must be adapted for use on Units 1 and 2. Engineering resources will continue to provide support during construction and commissioning.

Agreements are in place for all of the major material supply and service contracts. Previously, FBC had planned to contract the major mechanical refurbishment and replacement for Units 1, 2, and 4[2], for which a request for proposal (RFP) was expected to be completed by year end 2017. This RFP was cancelled and FBC opted to procure fabrication and machining services on a component by component basis. The cancellation of the RFP is discussed in further detail in Section 1.3.2.1.

The construction schedule remains unchanged from the previous update provided in the Annual Review for 2018 Rates.

1.3 *MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE*

1.3.1 Detailed Engineering

The technical and performance specifications for the project, which can be used on all units and common systems, as applicable to the project scope, have been completed.

Detailed engineering for Unit 4 is now complete. The mechanical engineering for Unit 4 was advanced from 2018 into 2017 to support the machining and fabrication RFP. The electrical design for Unit 4, which is essentially a replication of the detailed engineering work completed for Unit 3, was completed in early 2018.

Remaining engineering work on the project includes the detailed engineering for Units 1 and 2. This engineering work will be a replication of the work completed for Units 3 and 4. The detailed

[2] Mechanical refurbishment of Unit 3 was completed in 2014.

engineering for Unit 1 is expected to start in Q4 2018, in order to support the February 2019 dismantle start date.

1.3.2 Procurement

FBC has completed the majority of the procurement for the project. Components were procured for all units, where possible, in order to standardize equipment and realize savings by purchasing multiple components. Major items procured include the generator bearing lubrication system, excitation system, high pressure governor system and unit control system, motor control centre, and generator stator and rotor rewind contract.

In general, the actual cost of material and services procured is consistent with the project estimate. One exception is the generator stator and rotor rewind contract which is approximately $1.3 million over the estimated cost. This is partially offset by reductions in contingency and removal costs. Another exception is the Unit 1 transformer, which is discussed in Section 1.3.2.2 below.

The remaining procurement items include the contracting of the machining and fabrication services for Units 1 and 2.

1.3.2.1 Machining and Fabrication

As discussed in the Annual Review for 2018 Rates, FBC planned to contract the major mechanical refurbishment and replacement for Units 1, 2, and 4[3], for which a request for proposal (RFP) was expected to be completed by year end 2017. The RFP was issued in Q4 2017.

The proposals received either did not meet the objectives of the RFP or contained pricing that was considerably higher than budgeted. FBC anticipated economies of scale by selecting a single vendor for the bulk of the mechanical components, however, these savings never materialized. As a result, FBC cancelled the RFP and individually bid each component.

FBC visited a number of machine shops across British Columbia and Alberta in order to broaden its available resources for this scope of work. Based on the information collected, specific vendors were invited to submit a bid for each mechanical component. Vendors were evaluated based on their submitted price, as well as their respective capability, capacity and availability to complete the work.

To manage quality, FBC engineering resources regularly visit the machine shops to inspect the new and refurbished components to make sure they meet quality expectations. These site visits continue to provide significant value as it allows FBC to monitor execution of the work and to quickly provide feedback to the machine shops.

[3] Mechanical refurbishment of Unit 3 was completed in 2014.

1.3.2.2 Unit 1 Transformer

FBC completed the tender for the supply of a new generator step-up (GSU) transformer for Unit 1. The new GSU transformer is expected to be delivered to site in Q2, 2019. Based on the value of the agreement, FBC has realized savings of approximately $0.150 million for the supply and delivery of the new GSU transformer. The forecast installation and commissioning costs remain unchanged.

1.3.3 Construction

Refurbishment of Unit 4 has been progressing favourably. The dismantling of Unit 4 commenced in February 2018 and was completed in April 2018.

The following pictures were taken during the dismantling of Unit 4.

Figure 1: Removal of Unit 4 Rotor Assembly

Figure 2: Unit 4 Rotor Assembly with Field Poles Removed

Figure 3: Thrust Bearing Assembly for Unit 4

Figure 4: Removal of Unit 4 Intermediate and Lower Turbines

The Unit 4 mechanical components were shipped to a number of machine shops throughout British Columbia and Alberta to be refurbished. Components are quality checked by FBC through continued site visits of the machine shops. Most components have been completed and will be returned to site in Q3 2018.

The generator rewind for Unit 4 was successfully completed between March 2018 and June 2018.

The following is a brief update on other components:

- The installation of the new Unit 4 trash racks and support beams is complete;
- The installation of the new Unit 4 excitation system is complete (commissioning remaining);
- The installation of the new Unit 4 protection and control system is complete (commissioning remaining);
- The installation of the new bearing lubrication system is ongoing;
- The installation of the new brake system is ongoing;
- The installation of the new governor system is ongoing; and
- The installation of the new cooling water system is ongoing.

The project remains on schedule and FBC anticipates returning Unit 4 to service in Q4 2018.

1.3.4 Environmental Planning

FBC developed a site specific Environmental Management Plan (EMP) for the project. Environmental monitoring is in place to ensure both internal FBC crews and contractors adhere to the environmental requirements.

The EMP developed for the project includes background information on applicable regulations and the impact on the project, prevention measures to ensure regulatory compliance, and communication plans to ensure all on-site personnel are working cohesively towards preventing incidents which may have an environmental impact.

1.4 *PROJECT CHALLENGES AND ISSUES*

1.4.1 Detailed Engineering

Detailed engineering for the project has progressed favourably since the project was approved in early 2017. As previously discussed, FBC completed a significant amount of engineering work for the project in 2017 as it was needed for the refurbishment of Unit 3 and to support the procurement for Unit 4.

FBC encountered some challenges during detailed design in the second half of 2017 which resulted in a greater than anticipated engineering effort. The majority of the challenges were related to interfacing modern equipment with antiquated designs. For example, the design of the servomotor interface for the new high pressure governor system was more complicated than anticipated due to the uncertainty surrounding the original construction of the governor actuator. Ultimately, the challenges encountered were resolved and the learnings will be applied to the subsequent units.

No significant detailed engineering challenges were encountered in 2018. At this point in time, FBC does not anticipate any further challenges or issues relating to detailed engineering for the UBO Refurbishment Project.

1.4.2 Construction and Commissioning

1.4.2.1 Unit 3 (2017)

Overall, the refurbishment of Unit 3 was a success. As previously discussed, Unit 3 was refurbished over the second half of 2017 and was successfully returned to service in Q4 2017. FBC encountered some challenges throughout construction related to as-found conditions being worse than anticipated. For example, during construction of the new trash racks for Unit 3, the support beams were found to be in poor condition and replacement was recommended by the engineering team. The impact of these challenges were offset by savings elsewhere or were absorbed using contingency.

Additionally, FBC encountered some minor issues and deficiencies with the new equipment during the commissioning of Unit 3. Although the level of troubleshooting was higher than anticipating, the corrective actions did not result in any major changes and therefore did not have a major financial or schedule impact on the Unit 3 refurbishment. FBC has applied the learnings from these challenges and does not anticipate similar challenges in the future.

1.4.2.2 Unit 4 (2018)

The refurbishment of Unit 4 has progressed favourably over the first half of 2018. FBC has not encountered any major challenges or issues during construction which will have a material impact on the completion date.

Overall, the as-found condition of the Unit 4 turbine components are of similar condition to the Unit 3 turbine components refurbished in 2013/14, which served as the basis of the project estimate. However, the condition of the turbine runners was found to be worse than anticipated. Section 1.4.2.2.1 discusses this specific challenge in greater detail.

1.4.2.2.1 UNIT 4 TURBINE RUNNER CONDITION ISSUES

During the Annual Reviews for 2017 and 2018 Rates, FBC identified that “the turbine runners and seals will require replacement or refurbishment” depending on the as-found condition. To

better understand the condition of Unit 4 a condition assessment was completed in June 2017, in conjunction with a planned annual outage, to provide a preliminary assessment of the condition of these runners to give FBC an indication whether the runners needed refurbishment or replacement. The assessment of other mechanical components was not possible without fully dismantling the unit. The preliminary findings from the third party engineering firm Engen Services Ltd. suggested that the turbine runners of Unit 4 were likely repairable, however a final decision would be made once the runners were removed.

FBC and Engen completed a detailed inspection in late February 2018 and confirmed the turbine runners were repairable. However, the level of effort required to repair the turbine runners was higher than anticipated. Whereas Unit 3 had limited cracking on the blades during the 2013/14 repairs (prior to the UBO Refurbishment Project), Unit 4 had considerable cracking with nearly every blade having some degree of cracking. FBC successfully completed repairs in March 2018.

The pictures below provide an indication of the as-found condition and repairs on one of the Unit 4 runners.

Figure 5: Weld Repair on Cracked Turbine Runner Blade

Figure 6: Weld Repairs on Cracked Turbine Runner Blades

Additionally, the crown and band seals on the turbine were in worse condition than anticipated. FBC had anticipated minor repairs to the seals however upon further review it was determined that significant repairs were required in order to restore them back to the required tolerances.

The picture below shows the crown and band seals on one of the Unit 4 turbines.

Figure 7: Crown and Band Seals, Unit 4 Turbine

In order to repair the crown and band seals, the existing seals must first be cut down using a lathe that is capable of handling the large equipment, which in this case is either two runners attached by a shaft or a single runner and shaft. Once the cutting is complete and the new seal band is fabricated, the new seal band is attached, radially bolted, and the lathe is then used to machine the seal to the required tolerance. The pictures below show the process in greater detail.

Figure 8: Damaged Turbine Runner Seal

Figure 9: Turbine Runner Seal after Machining

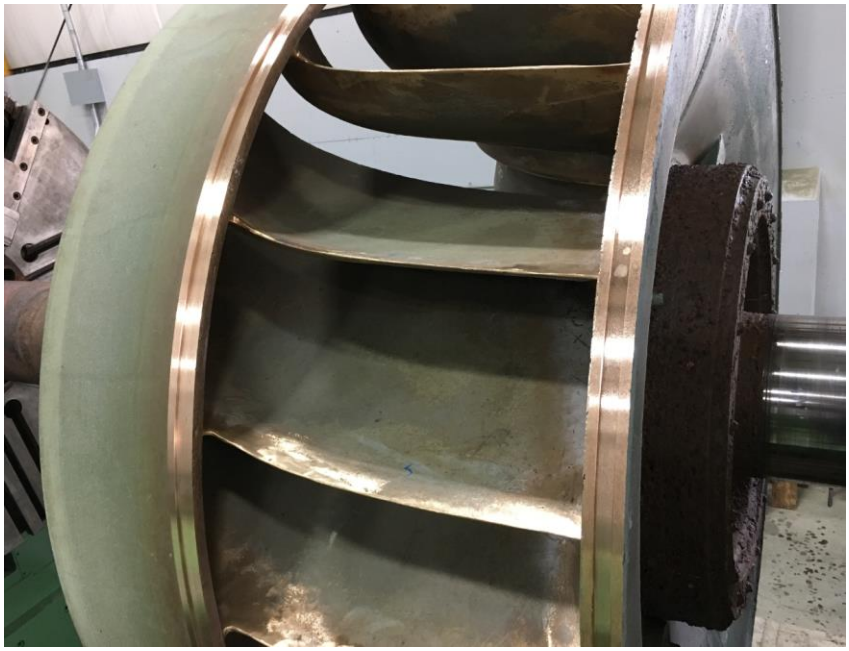


Figure 10: - New Band Seal Attached, prior to cutting

Figure 11: Refurbishment of Seals Complete

The repair for the seals for Unit 4 is approximately $250,000 over the estimated cost. This additional cost is offset by reductions in contingency. There is no anticipated schedule impact as these repairs are not currently on the critical path of the project schedule.

2. PROJECT SCHEDULE

Major milestones associated with Unit 4 have been identified in the milestone summary below. Construction schedules for the remaining units are described in section 2.3.4.

Table C-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	13/10/2017	13/10/2017	Complete
Unit 4 Detailed Engineering	30/03/2018	30/03/2018	Complete
Procurement			
Transformer	01/01/2020	09/08/2017	Complete
Major Unit Mechanical	01/01/2018	29/12/2017	RFP cancelled, components bid individually.
Construction			
Dismantle of Unit 4	06/04/2018	06/04/2018	Complete
Installation of new High Pressure Governor System	18/06/2018	29/06/2018	Ongoing
Installation of new Excitation System	29/06/2018	12/08/2018	Ongoing, cubicles installed.
Installation of new Unit Protection and Control	01/08/2018	10/08/2018	Ongoing, cabinets installed.
Generator Rewind	07/06/2018	27/06/2018	Complete
Re-Assembly	25/09/2018	25/09/2018	
Unit 4 Returned to Commercial Service	26/10/2018	26/10/2018	

2.1 *SCHEDULE PERFORMANCE TO DATE*

Engineering is largely completed, with the exception of some detailed design for Units 1 and 2. The drawings created for Units 3 and 4 will need to be updated for Units 1 and 2. The majority of the procurement is now complete as most contracts are now in place and expected delivery dates are on schedule.

The dismantling of Unit 4 began ahead of schedule in February 2018. Voith Hydro began work on the generator rewind in late February 2018 and was completed in June 2018.

The following is a brief update on other completed components:

- The installation of the new Unit 4 trash racks and support beams is complete;
- The installation of the new Unit 4 excitation system is complete (commissioning remaining); and
- The installation of the new Unit 4 protection and control system is complete (commissioning remaining).

Progress on the new governor system, bearing lubrication system, and the cooling water system has been favourable. These items remain on schedule.

Figure 12: New Unit 4 Governor System and Oil Lubrication System

2.2 SCHEDULE PROJECTION GOING FORWARD

For the remainder of 2018, engineering resources will be focused on providing construction and commissioning support for Unit 4.

Procurement for Unit 4 is complete. Procurement of machining and fabrication services for Unit 1 is expected to occur in Q4 2018.

Construction for Unit 4 remains on target. Reassembly is expected to begin in August 2018, with unit alignment completed in September 2018. Commissioning is expected to begin in September 2018 and be complete by end of October 2018. FBC expects to return Unit 4 to service in October 2018.

Construction for the remaining units is scheduled as follows:

- Unit 1: February 2019 – November 2019
- Unit 2: February 2020 – November 2020
- Plant wrap-up: December 2020 – April 2021

2.3 SCHEDULE DIFFICULTIES AND VARIANCES

As previously discussed in the Annual Review for 2018 Rates, based on progress to date FBC has advanced the dismantling start date for the remaining units from March, as originally scheduled, to February of the respective year in order to provide additional schedule contingency. The project schedule remains on target.

2.4 PROJECT SCOPE CHANGE SUMMARY

Throughout detailed engineering, FBC has made minor adjustments in order to address some unforeseen challenges and issues. These adjustments do not represent significant scope deviations and do not have a major financial or schedule impact.

Any engineering deviations from the original scope are captured and documented through FBC's change management procedures.

With respect to the plant, scope changes to date include floor modifications for removal and disposal of asbestos and other minor issues identified during demolition of the old switchgear structure, and the requirement for one additional tail race gate in order to work through high tail water during freshet, at an aggregate cost of approximately $0.115 million.

With respect to the generator units, scope changes to date are largely related to the generator rewind. Specifically, changes were driven by the as-found configuration of the rotor poles being different than anticipated and the as-found condition of certain stator and rotor components being worse than anticipated. For example, the as-found condition of the rotor pole connectors

on both Unit 3 and Unit 4 were worse than anticipated and required replacement, at an aggregate cost of approximately $0.113 million. Scope changes related to the generator rewinds of Unit 3 and Unit 4 have had a cumulative financial impact of approximately $0.232 million to date.

The overall project schedule is not affected.

3. PROJECT COSTS

The following table outlines the project expenditures to June 30, 2018 and the forecast project expenditures to completion.

Table C-2: Cost Summary

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent	Variance Explanations
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)	
	($000s)				(%)		
Unit 3	4,079	6,128	86	6,214	52%	150%	Advancement of engineering effort from future years into 2017 in addition to higher than anticipated stator and rotor rewind new construction costs. Remaining expenditures are related to minor deficiencies which will be addressed post-freshet.
Unit 4	6,634	5,027	2,393	7,419	12%	59%	Completion of Unit 4 turbine assessment, and higher than anticipated stator and rotor rewind costs. Higher than anticipated machining/fabrication costs related to poor mechanical component condition.
Unit 1	8,050	668	6,805	7,473	-7%	8%	Forecasting under budget. Anticipating engineering effort will be lower than expected as engineering from previous units can be updated for use on Unit 1. FBC is anticipating savings from the application of learnings and from increased productivity.
Unit 2	5,641	438	5,035	5,473	-3%	8%	Forecasting under budget. Anticipating engineering effort will be lower than expected as engineering from previous units can be updated for use on Unit 2. FBC is anticipating savings from the application of learnings and from increased productivity.
Common	860	397	342	739	-14%	46%	Forecasting under budget due to lower than anticipated costs related the AC/DC Station Service work. Plant Wrap-Up work remaining in 2021.
Subtotal - Construction	**25,264**	**12,657**	**14,660**	**27,318**	**8%**	**50%**	
Cost of Removal	1,880	826	670	1,496	-20%	44%	Lower than anticipated removals for stator and

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent	Variance Explanations
							rotor rewind, transformer containment, and engineering and construction management support during removals
Project Contingency	3,771	-	1,781	1,781	-53%	0%	Contingency has been reduced by $2.0 million to reflect significant proportion of engineering / procurement / construction complete).
Subtotal- Construction & Removal	**30,916**	**13,483**	**18,269**	**30,585**	**-1%**	**44%**	
AFUDC	867	314	874	1,188	37%	36%	Advancement of engineering and procurement.
Total Project Cost	**31,783**	**12,600**	**19,182**	**31,783**	**0%**	**43%**	

In the Annual Review for 2018 Rates, FBC forecast the total for Unit 3 to be $5.399 million. The advancement of engineering effort from future years into 2017 and the higher than anticipated stator and rotor rewind costs were largely responsible for the $1.320 million variance.

The forecast total for Unit 3 is currently $6.214 million, which represents a variance of $2.135 million over budget. The additional $0.815 million, the variance between the present forecast total for Unit 3 in 2018 and the previous forecast total for Unit 3, is mainly driven by the as-found condition of components, increased project definition through detailed engineering, and the complexity of installing modern equipment in an antiquated operating plant. Examples include:

- the new high pressure governor system – the installation and commissioning of the new high pressure governor system required additional effort driven by the interfacing of modern equipment with an antiquated design;
- the new braking system – additional engineering effort was required to confirm the feasibility of the new braking system installation;
- the new trash racks – the as-found condition of the trash rack support beams was worse than anticipated and replacement was required; and
- the generator rewind – the generator rewind scope of work was increased to account for the replacement of the pole to pole connectors and for the refurbishment of the rotor fans, which was required due to worse than anticipated as-found condition of these components.

The project estimate was approved as Class 4 in the Annual Review for 2017 Rates because it was difficult to achieve further level of definition without dismantling the units. As a result, more project definition was achieved during the refurbishment of Unit 3. The solutions developed to address these uncertainties and challenges by FBC engineering and construction crews have resulted in considerable learnings which have been applied to Unit 4 and will be applied to Units 1 and 2. FBC believes the construction and commissioning of Units 1 and 2 will be more efficient as potential issues and risks are addressed proactively through improved mitigation and contingency measures.

In summary, the total project forecast remains consistent with the original budget. While there are instances where forecast costs are higher than budgeted, they have been offset by reductions in contingency and forecast removal costs.

4. PROJECT RISKS

FBC continues to make efforts to reduce the risk profile of the UBO Refurbishment Project through the use of lump sum contracts and the use of preliminary condition assessments for the turbines.

FBC has completed the majority of the procurement for the project. Components were procured for all units, where possible, in order to standardize equipment and realize savings by purchasing multiple components.

Due to the unit design it is not possible to determine the condition of the mechanical components prior to dismantle and therefore it is not possible to say which components can be refurbished and which components require replacement prior to dismantle. However, it is possible to complete a preliminary condition assessment of the turbines prior to unit dismantle. The preliminary condition assessment of the turbines provides FBC an opportunity to determine whether there is any visible damage to the turbines which would result in replacement. This has two favourable impacts on risk:

1. it reduces the likelihood of replacement as the visible portion of the respective turbine runner has been inspected and no significant visible damage (which would result in replacement) found; and

2. it reduces the impact of a replacement determination at that point in time as it affords FBC an additional 6-8 months (prior to unit dismantle) to procure new turbine runners.

In short, the preliminary condition assessments of the turbines do not fully address the risk of having to replace the turbines. Rather, these assessments reduce the likelihood of the risk occurring and the impact of this risk should it materialize.

The major financial and schedule risks are related to the as-found condition of submerged turbine components (Section 4.1) and the as-found condition of the stator cores (Section 4.2). FBC continues to work towards reducing the impact of these risks by identifying condition as soon as practically possible through the use of condition assessments, where possible.

Safety and environmental risks continue to be managed using FBC's safe work planning procedures.

4.1 *AS-FOUND CONDITION OF SUBMERGED TURBINE COMPONENTS*

As previously discussed, there is a risk that the as-found condition of submerged turbine components could be worse than anticipated, resulting in a requirement for replacement rather than refurbishment.

The most significant component of this risk is associated with the turbine runners. Typically, there is a single turbine runner per generating unit. However, in the case of the units in the Upper Bonnington Old Plant, each unit has three turbine runners. For Units 1, 2 and 4, FBC included the cost of replacing two of the runners in the project, while refurbishing the remaining seven. The runners for Unit 3 were successfully refurbished in 2013/14 and the runners for Unit 4 were successfully refurbished in 2018.

As discussed above, replacing turbine runners would also have a considerable schedule impact. The procurement period for the turbine runners is between six to twelve months. To mitigate this impact, FBC will be completing a preliminary condition assessment of the turbine runners for each unit before unit dismantle in order to allow sufficient time to procure replacement runners.

4.2 *AS-FOUND CONDITION OF STATOR CORE*

Initially, there was a risk that the as-found condition of the stator core of each unit (excluding Unit 2) could be worse than anticipated. While recent condition assessment reports did not indicate any visible issues, FBC stated that non-destructive testing upon unit dismantle would be required for FBC to ascertain the true condition of the stator cores.

Since the project was approved in 2017, the stator cores of Units 3 and 4 were found to be in acceptable condition and were therefore not replaced. The true condition of the Unit 1 stator core will remain unknown until Unit 1 is dismantled in 2019. FBC does not anticipate any issues related to the as-found condition of the Unit 2 stator core as it was previously replaced as part of the repairs completed after the unit failure in 1995.

5. CONCLUSION

The UBO Refurbishment Project continues to track according to schedule. While the forecast annual spend has changed since the submission of the project in 2017, the total project forecast remains on-target. FBC continues to focus on safe execution of construction work and on reducing the risk profile of the project.

FBC continues to leverage detailed design work completed to-date and apply learnings to-date in order to benefit the remaining units. The engineering effort required for the remaining two units is expected to decrease as drawings created for Units 3 and 4 are adapted for use on Units 1 and 2. Additionally, the learnings from the refurbishment of Units 3 and 4 which will be applied to Units 1 and 2. FBC believe this will have a positive impact on the cost and time required to refurbish the remaining units.

Appendix D

RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

Appendix D

FortisBC Inc.

Ruckles Substation Rebuild Project

Status Report

August 2018

1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the Commission approved capital expenditures related to the Ruckles Substation Rebuild project (Ruckles project) by Order G-8-17. The Commission directed FBC to provide the following information about the progress of the project as part of its annual review applications.

- The status of the Ruckles project, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to the updated project timeline, as at the time of filing each annual review application.
- Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application.
- The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the [Annual Review for 2017 Rates] Application, with explanations for any variances.[1]

The Ruckles project involves rebuilding the existing Ruckles Substation, together with the necessary transmission and distribution modifications, primarily to address issues of age and the substation's location in the identified flood zone of the Kettle River, in order to continue to safely supply electricity to the City of Grand Forks (CoGF) municipal electric utility and surrounding area. FBC submits the following report in compliance with Directive 5 of Commission Order G-8-17, including the project status and costs, which are current as of June 30, 2018.

1.2 *GENERAL PROJECT STATUS*

In the Annual Review for 2017 Rates in which approval was requested, the Ruckles project had an AACE Class 3 capital cost estimate of $8.288 million in as-spent dollars (including $0.428 million of AFUDC and $0.301 million of removal costs). Project expenditures to June 30, 2018 are approximately $5.772 million. Final project costs are currently estimated at $6.913 million, or $1.375 million or 16.6 percent lower than estimated, due to savings associated with the elimination of 13 kV to 4 kV step-down equipment which is no longer necessary (discussed

[1] G-8-17, Appendix A, page 15.

further below), favourable actual costs for major equipment compared to budget allowances, and the release of risk and project contingency.

FBC does not anticipate any significant variances from the project schedule as presented in the business case. Construction is at 77 percent completion, with the majority of the remaining work being civil-related.

Significant areas of Grand Forks, including the old Ruckles Substation, experienced extensive flooding in May 2018. The floodwaters reached levels consistent with those expected for a 1 in 200 year event; the possibility of such an event was one of the main drivers for the Ruckles project. Emergency flood response, including the installation of a mobile transformer, placement of concrete blocks and sandbags for flood control, and contractor support to operate dewatering pumps and provide site clean-up resulted in a small amount of additional costs to the project. The newly constructed, elevated Ruckles Substation did not sustain flood damage. By successfully maintaining scheduled milestones, the new equipment was installed, commissioned, and energized before the floodwaters damaged the old substation, thereby avoiding extended and extensive outages to FBC and CoGF customers.

1.3 *MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE*

1.3.1 Project Engineering

As described in the previous Status Report provided as part of the Annual Review for 2018 Rates, the existing Ruckles Substation is supplied by two FBC transmission lines and provides a distribution supply source to direct residential, irrigation and commercial customers of FBC (at 13 kV), the electrical utility of the City of Grand Forks (at both 13 kV and 4 kV), and an industrial sawmill customer (at 4 kV).

Following Commission approval of the project, and to seek out project cost savings, FBC initiated discussions with the CoGF municipal electric utility to explore whether the CoGF would be willing to advance its ongoing 4 kV to 13 kV system voltage conversion project so that it would be completed by June 1, 2018. The CoGF was originally anticipating completion of the conversion project in 2018/2019. An earlier conversion allowed FBC to eliminate the 4 kV infrastructure requirements associated with the CoGF supply from this project and to achieve project cost savings. In June 2017, the CoGF accepted FBC's offer to contribute a portion of the project savings in order to advance the voltage conversion.

FBC also held discussions with its industrial customer, Interfor Corporation (Interfor) to explore whether Interfor would also be willing to convert its equipment from 4 kV to 13 kV by June 1, 2018. Following initial discussions, Interfor engaged a third party to develop a scope and estimate for the conversion. FBC and Interfor then reached an agreement whereby FBC contributed a portion of Interfor's costs of conversion.

By removing the 4 kV supply infrastructure from the Ruckles project, gross cost savings were approximately $0.500 million, less contributions to the CoGF and Interfor. Including the contributions, the net cost savings were approximately $0.250 million.

All civil and structural design was completed and Issued for Construction (IFC) packages were received by the FBC Project Management Office (PMO) on April 28, 2017. The electrical tender package was issued to the PMO on May 19, 2017. This tender package was issued as part of the Request for Quotation (RFQ) to four vendors on June 6, 2017. The detailed electrical construction package was issued in September 2017.

1.3.2 Procurement

All major equipment was received and has been installed on site. The Electrical construction contract is 77% complete. The contract scope of work includes the civil and site, structures and bus work, station equipment and apparatus, protection, control, and metering, and removal of existing equipment.

1.3.3 Environmental Planning

FBC has developed a site specific Environmental Management Plan for the project. Both internal FBC crews and contractors are expected to meet or exceed the environmental requirements.

1.3.4 Permits and Approvals

There are no outstanding permits or approvals required.

1.4 *PROJECT CHALLENGES AND ISSUES*

1.4.1 Detailed Engineering

Geotechnical and soil characterization studies were completed to verify site conditions. Surveys and historical information were also used to determine site elevations. This allowed engineering to design the project above the flood plain by reconstructing the station two metres above the existing grade.

1.4.2 Communications and Stakeholder Engagement

Communications with the CoGF and Interfor are complete. Both parties agreed to convert from a 4 kV to 13 kV supply. As explained in section 1.3.1, this has reduced the project capital cost, improved system reliability by reducing the amount of installed equipment, and allowed FBC to achieve efficiencies by not having to maintain non-standard 4 kV equipment.

1.4.3 Construction and Commissioning

The Ruckles Substation and surrounding areas in the Grand Forks area experienced extensive flooding in May 2018, with water levels consistent with those expected for a 1 in 200 year event.

On the morning of May 11, rising floodwaters breached a temporary sandbag dike erected by FBC around the old Ruckles Substation. Water levels in the station yard and control buildings quickly reached the levels foreseen in the project application (refer to Project photos in section 1.4.4 below). This forced the deenergization of the station to manage the extreme safety hazards associated with flooded high voltage equipment. Although not all aspects of the project were complete, construction of the new station was sufficiently advanced that the electrical infrastructure was available to provide safe and reliable service. FBC was able to expedite the remaining commissioning and only a short unplanned outage occurred before load was transferred from the unserviceable equipment in the old Ruckles Substation to the new substation equipment. Additional emergency flood response, including the installation of a mobile transformer to provide a temporary 4 kV supply, concrete block and sandbag installations, and contractor support to operate dewatering pumps and site clean-up, resulted in approximately $70 thousand of additional costs to the project, but no significant schedule delays occurred. The project is now scheduled to be complete by the end of August 2018.

Field equipment commissioning was completed by a third party contractor. All protection and control commissioning was completed by internal FBC employees. Both Interfor and the CoGF have fully converted to the new 13 kV voltage and are being supplied from the new Ruckles Substation.

1.4.4 Project Photos

Figure 1: Old Ruckles Substation T1 transformer and FDR4 / FDR5 circuit breakers three days after peak flooding (note high water marks on equipment)

Figure 2: Old Ruckles Substation control building interior (note high water marks on switchgear panels)

Figure 3: New Ruckles Substation control building (left) and general area flooding (note substantial elevation difference between old substation fence on the right and the new fence on the left)

Figure 4: New Ruckles Substation
(photo taken shortly after the flood peak)

2. PROJECT SCHEDULE

Major milestones have been identified in the schedule below. Milestone targets will continue to be monitored, and variance explanations will be documented.

Table D-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering/Procurement:	Q4-2018		In progress
9L 63 kV reconfiguration(IFC)	Q1-2017	March 31, 2017	Complete
Control room (IFC)	Q2-2017	May 11, 2017	Complete
Site/Civil (IFC)	Q2-2017	April 14, 2017	Complete
Electrical/Physical (IFC)	Q2-2017	June 5, 2017	Complete
Issue RFQ	Q2-2017	June 6, 2017	Complete
Steel (IFC)	Q2-2017	June 15, 2017	Complete
Issue Contract	Q3-2017	July 14, 2017	Complete
Major equipment delivery	Q4-2017	December 2018	Complete
Construction:			
Civil/site Phase 1 (pre-construction)	Q4-2017	November 2017	Complete
Civil/Site Phase 2 (completion)	Q4-2018		In progress
Buildings	Q2-2018	May 2018	Complete
Structures/Buswork	Q4-2018	May 2018	Complete
Station Equipment/Apparatus	Q3-2018	June 2018	Complete
Communication/SCADA	Q2-2018	June 2018	Complete
Protection/Control/Metering	Q2-2018	May 2018	Complete
Commissioning	Q3-2018	June 2018	Complete
Distribution Line work	Q3-2018		In progress
Equipment removal	Q4-2018		In progress
Project Completion	Q4-2018		

2.1 *SCHEDULE PERFORMANCE TO DATE*

Procurement and Contracts are on schedule.

2.2 SCHEDULE PROJECTION GOING FORWARD

Major milestones and completion dates were reviewed and agreed to by FBC and the contractor. Changes in scope and schedule during equipment salvage and reclamation will continue be monitored and controlled.

2.3 SCHEDULE DIFFICULTIES AND VARIANCES

2018 floodwaters slightly delayed construction, but project completion is still scheduled for August 2018.

2.4 PROJECT SCOPE CHANGE SUMMARY

Successful negotiations with the CoGF and Interfor allowed FBC to remove the 4 kV portion of the project. This created some Civil and Electrical design changes for the project. Specifically, two padmount transformers and the associated containment systems and foundations were removed from the scope of work.

FBC change management procedures have been used to manage design and scope change.

3. PROJECT COSTS

The following table outlines the project expenditures to June 30, 2018 and the forecast project expenditures to completion.

Table D-2: Cost Summary

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percent Budget Spent	Variance Explanation
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)	
	($000s)				(%)		
Line Work	241	249	38	288	19%	103%	High water table when transmission poles installed. Vacuum truck required
Civil & Site	1,688	1,394	324	1,718	2%	83%	
Buildings	191	209	0	209	9%	109%	
Structures & Buswork	427	508	6	514	20%	119%	Scope addition for animal guarding and capacitor bank breaker replacement
Station Equipment & Apparatus [2]	2,602	1,780	0	1,780	-32%	68%	4 kV to 13 kV voltage conversion savings and favourable equipment pricing
Communications & SCADA	32	39	0	39	23%	123%	Additional material required
Protection, Control & Metering	270	258	9	267	-1%	96%	
Design	627	663	31	693	11%	106%	Additional engineering required for 4 kV-13 kV conversion
Commissioning	132	112	10	122	-7%	85%	
Project Management	544	250	80	330	-39%	46%	Internal FBC dual role construction / project manager. Did not have to contract out on site construction manager.
Subtotal - Construction	6,754	5,462	497	5,959	-12%	81%	
Cost of Removal	301	77	145	223	-26%	26%	Savings on non-PCB oil disposal

[2] FBC's contributions to the 13 kV system voltage conversion of the City of Grand Forks and Interfor are included in the value of Station Equipment and Apparatus.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percent Budget Spent	Variance Explanation
Project Contingency	805	0	314	314	-61%	0%	Identified potential risks did not materialize
Subtotal-Construction & Removal	7,860	5,539	957	6,496	-17%	70%	
AFUDC	428	233	184	417	-3%	55%	
Total Project Cost	8,288	5,772	1,141	6,913	-17%	70%	

The forecast project cost is $1.375 million lower than the business case forecast as a result of eliminating the 4 kV equipment from the substation, favourable actual costs for major equipment compared to budget allowances, and the release of project risk and contingency. Additional details are included in Table C-2 above.

4. PROJECT RISKS

4.1 *SCHEDULE RISKS*

Floodwaters have now receded and Interfor and the CoGF have completed their 4 kV to 13 kV conversions. Remaining schedule risks are low.

4.2 *COST RISKS*

Cost risks remaining for the project include risks associated with the occurrence of contaminated soil disposal, additional excavation, and grounding deficiencies.

4.3 *ENVIRONMENTAL RISKS*

Environmental risks mainly include potential equipment oil spills. This risk will be mitigated with on-site spill kits and emergency response plans.

Asbestos was present in the old control room. A third party contractor was hired to remove and dispose of the asbestos before the control room was removed from the site.

Contaminated soil may also be present and could result in increased project costs. Any soil removed from site will be sampled and disposed of at an approved dumpsite.

FBC has developed a site specific Environmental Management Plan for the project.

5. CONCLUSION

The new Ruckles Substation was successfully energized in May 2018 to address imminent damage to equipment in the old Ruckles Substation resulting from flooding in the Grand Forks area consistent with anticipated 1 in 200 year flood levels. Had FBC not proceeded with the project, extensive and extended outages to FBC direct customers, City of Grand Forks customers, and the Interfor sawmill would have been inevitable. There would also have been substantial unforeseen costs associated with addressing damaged equipment and potential environmental mitigation.

Project completion continues to track according to schedule. Project cost savings resulted from successful negotiations with Interfor and the CoGF allowing FBC to remove the 4 kV voltage system requirements from the project scope. Favourable equipment pricing and the release of risk and contingency also contributed to the project cost savings.

Appendix E

DRAFT ORDER

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2019 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 15, 2014, the British Columbia Utilities Commission (Commission) issued its Decision and Order G-139-14 approving for FortisBC Inc. (FBC) a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2019 (the PBR Decision). In accordance with the PBR Decision, FBC is to conduct an Annual Review process to set rates for each year;

B. By letter dated July 26, 2018, FBC proposed a regulatory timetable for its annual review for 2018 rates;

C. By Order G-142-18 dated July 31, 2018, the Commission established the Regulatory Timetable for the annual review for 2019 rates which included the anticipated date for FBC to file its annual review materials, the deadline for intervener registration, one round of information requests, a workshop, FBC's response to undertakings requested at the workshop, and written final and reply arguments;

D. On August 10, 2018, FBC submitted its Annual Review for 2019 Rates Application materials (Application) seeking approval of, among other things, to maintain existing 2018 rates, effective January 1, 2019. The Application is made pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA);

E. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the Commission orders as follows:

1. FortisBC Inc. (FBC) is approved to maintain 2019 rates at the approved 2018 levels, effective January 1, 2019;

2. Approval is granted for FBC for the following non-rate base deferral account requests:

    - Creation of a deferral account for the 2018 DSM Expenditure Schedule application, to be financed at the Company's short term interest (STI) rate, with a one-year amortization period;
    - Creation of a deferral account for the Rate Design and Rates for Electric Vehicle (EV) Direct Current Fast Charging Service Application, to be financed at FBC's STI rate, with disposition to be proposed in a future application;
    - Creation of a deferral account for costs related to FBC's participation in British Columbia Hydro and Power Authority's (BC Hydro) Waneta 2017 Transaction application, to be financed at FBC's STI rate, with a one-year amortization period;
    - The addition of the 2019 revenue surplus of $4.204 million after tax to the existing 2018 Revenue Deficiency Deferral Account, which will be renamed to the 2018 – 2019 Revenue Surplus Deferral Account, and the financing of this account at FBC's weighted average cost of debt (WACD);
    - A four-year amortization period for the existing Multi-Year (2019-2022) Demand Side Management Expenditures deferral account, commencing in 2019;
    - A five-year amortization period for the existing 2017 Cost of Service Analysis and Rate Design Application deferral account, commencing in 2019; and
    - Amortization of the existing Castlegar Office Disposition deferral account in 2019.

3. Z-factor treatment is approved for the 2019 Employer Health Tax, 2018 and 2019 MSP premium reductions, and 2018 incremental operations and maintenance expenses and capital expenditures related to Mandatory Reliability Standards Assessment Reports No. 8 and 10, as described in Section 12.2 of the Application.

4. Approval is granted for FBC to recognize cloud computing implementation costs to be capitalized consistent with traditional on-premise hardware and software for 2019 as described in Section 12.3.1.2 of the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner