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September 4, 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 Energy Inc. (FEI or the Company)

Application for 2019 and 2020 Revenue Requirements and Rates for the Fort Nelson Service Area (the Application)

Attached please find FEI's Application for 2019 and 2020 Revenue Requirements and Rates for the Fort Nelson Service Area.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FEI Fort Nelson 2017-2018 RRA

FortisBC Energy Inc.
Fort Nelson Service Area

Application for 2019 and 2020 Revenue Requirements and Rates

Volume 1 - Application

September 4, 2018

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1. SUMMARY, BACKGROUND, APPROVALS SOUGHT AND PROPOSED REGULATORY PROCESS

1.1 SUMMARY

FortisBC Energy Inc. (FEI or the Company) is filing this Application for 2019 and 2020 Revenue Requirement and Rates (2019/2020 RRA or the Application), seeking approval of its rates for delivery service to customers on the natural gas distribution system in the Fort Nelson Service Area (FEFN) for 2019 and 2020 (the Test Period). As explained in this Application, the proposed rates over the Test Period and other approvals sought are required to ensure that the Company's rates recover the costs of serving its customers in FEFN.

On February 2, 2017, FEI filed a supplemental filing to its 2016 Rate Design Application (RDA) with the British Columbia Utilities Commission (BCUC or the Commission) which included a review of the rate design for FEFN. On January 9, 2018, the BCUC issued Order G-4-18 and Reasons for Decision on FEI's proposed Cost of Service Analysis and Revenue to Cost Ratios, and on July 20, 2018 the BCUC issued Order G-135-18 and Reasons for Decision on the balance of FEI's RDA (together referred to as the RDA Decision). The RDA Decision approved FEI's proposed rate design for FEFN. The delivery rates and rate structure (together referred to as the 2018 RDA Rates) as approved by the RDA Decision will be in effect on January 1, 2019, which coincides with the proposed delivery rate changes as a result of FEFN's 2019 revenue requirements proposed in this Application. The rate changes for FEFN customers in 2019 will therefore be a combination of the RDA Decision and the 2019/2020 revenue requirements decision. Section 2 of the Application provides an overview of the approved rate design changes and the impacts to FEFN from 2019 onwards.

FEFN's revenue requirements for 2019 and 2020 are determined by various business drivers including operating and maintenance expenses, taxes, capital additions, financing costs and return on equity. Detailed supporting material has been provided in Sections 3 through 10 of the Application which show the impact of these business drivers on the FEFN revenue requirements. Included in Section 11 are financial schedules providing a detailed account of FEI's revenue requirements and the proposed rates for the Test Period.

Based on the forecast energy demand for FEFN, FEFN's forecast revenue at the 2018 RDA Rates is not sufficient to recover FEFN's required revenue requirement over the Test Period. Specifically, there is a revenue deficiency of $101 thousand in 2019 and a further revenue deficiency of $180 thousand in 2020, for a cumulative 2020 revenue deficiency of $281 thousand compared to the forecasted 2020 revenue at the 2018 RDA Rates.

The largest driver of the revenue deficiency is the decrease in energy demand. As discussed in Section 4 of the Application, FEFN is forecasting low customer growth and a declining use per customer for both the residential and commercial customer classes. As a result, total energy demand is forecast to decline over the Test Period and the decrease in demand compared to

2018 Approved energy demand contributes $270 thousand out of the net revenue deficiency of $281 thousand over the two-year Test Period.

Other contributing factors to the net revenue deficiency are:

- Rate base growth due to capital expenditures required for system growth and maintenance contributes $58 thousand to the net revenue deficiency to the two-year Test Period. Details on FEFN's required capital expenditures are provided in Section 8 of the Application,
- An increase of $46 thousand in depreciation expense to the Test Period primarily due to additions to Distribution Plant in 2018 and upgrades to Fort Nelson office building,
- An increase of $30 thousand in amortization expense to the Test Period mostly attributable to the proposed 2019-2020 Revenue Requirement Application deferral account, the discontinuation of the credit balance in the Customer Service Variance account, and the Billing System Change Costs for FEFN Rate Changes as approved in the RDA Decision for FEFN, and
- An increase of $54 thousand in taxes mostly attributable to the tax impacts of increases in revenue over the two-year Test Period.

The revenue deficiency items noted above are partially offset over the Test Period by the following:

- Compared to 2018 Approved, the O&M is reduced by $20 thousand over the Test Period primarily due to lower labour costs, employee expenses, and facilities costs. Details on FEFN's required operating and maintenance costs are provided in Section 6 of the Application,
- A reduction of $11 thousand in property taxes over the Test Period, and
- The ending of any amortization of the 2017 revenue deficiency ($146 thousand) as it was fully amortized in 2018. .

As part of this Application, FEI is seeking a Certificate of Public Convenience and Necessity (CPCN) for an extension of FEI's distribution system in FEFN resulting from its purchase of the gas distribution assets from Prophet River First Nation (PRFN), with 53 residential and six commercial customers currently attached to the system (the Prophet River Extension). The estimated acquisition cost is ten dollars[1], plus approximately $8 thousand in legal fees. If the CPCN is approved, FEI will conduct the safety procedure of surveying the pipeline, relocate risers if necessary, and install individual gas meters to the 53 residential and six commercial properties. The estimated capital expenditure for the work is $104 thousand, which is included

[1] PRFN is not expecting remuneration for the distribution asset but for the purpose of having a binding contract for a legal transaction, there needs to be an exchange of value between the contracting parties, as a result, the purchase price is set at ten dollar as a nominal value.

in the 2019 capital expenditure forecast. Refer to Section 10 for further detail on the PRFN Project.

Consistent with past practice, FEI is also seeking approval of a deferral account for FEFN to capture the costs of this revenue requirement application and proceeding.

The Company is not requesting approval of forecast gas costs with this Application. Instead, any rate changes related to the flow-through of gas costs are dealt with in separate applications to the Commission. Any variations between forecast and actual gas costs will continue to be returned or recovered from customers through the existing deferral account mechanism approved by the Commission.

The approvals sought in this Application appropriately recover the costs of serving FEFN customers and the required capital improvements to continue service to FEFN customers. Although the proposed rates reflect a cumulative increase of 12.61 percent over the delivery portion of the approved 2018 RDA Rates (a cumulative increase of 9.62 percent on an average burner tip[2] basis), it is not uncommon for significant rate changes to occur due to the relatively small customer base in Fort Nelson. For example, in the last five years, the burner tip impacts in FEFN have fluctuated between a decrease of approximately 21 percent to an increase of approximately 33 percent.[3] FEI believes that the proposed rates for FEFN are reasonable, allowing the Company to recover its forecast costs of providing natural gas service to customers.

Given that FEI expects that permanent rates will not be able to be approved prior to the beginning of the Test Period, FEFN is seeking approval of an interim, refundable delivery rate increase of 4.37 percent effective January 1, 2019 (which is incremental to the rate impacts of the already-approved RDA Decision), and an interim, refundable Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider of $0.199 per GJ effective January 1, 2019.

1.2 *BACKGROUND*

This section outlines the corporate history of FEI and its operations in FEFN as well as the applicable regulatory context.

1.2.1 History of FEI

FEI is one of the largest natural gas distribution companies in Canada, based on number of customers and service area. FEI's customer base for the provision of natural gas transmission and distribution services includes more than one million residential, commercial and industrial

[2] Commodity plus delivery or total bill basis.

[3] Specific burner tip impacts outlined are representative of Rate Schedule 1 (residential) customers. The approximate 33 percent burner tip increase references the Commission approved April 1, 2014 Gas Cost Recovery Charge increase from $2.846 per GJ to $4.775 per GJ. The approximate 21 percent burner tip decrease references the Commission approved April 1, 2015 Gas Cost Recovery Charge decrease from $4.259 per GJ to $2.579 per GJ.

customers located in the Mainland, Vancouver Island and Whistler service areas. FEI, through its parent company FortisBC Holdings Inc., is a wholly owned subsidiary of Fortis Inc., a leader in the North American regulated electric and gas utility industry.

FEI is responsible for the procurement and supply of natural gas to the majority of its customers. For customers in all of its service areas, the Company purchases its supply of gas from a number of producers, aggregators and marketers. FEI also contracts with various providers for service on upstream pipelines, capacity in underground storage facilities and various types of peaking and gas supply cost mitigation arrangements.

The gas supply, transmission and distribution functions of FEI focus on activities that are integral to the safe, reliable and efficient running of utility operations. Beyond the front line activities such as responding to emergencies, and constructing, installing and operating the transmission and distribution system, there are a number of key support functions. These include planning and designing facilities, corrosion control, metering, meter reading, leak surveying, right of way management and materials management and distribution.

Also important are the systems and services that allow FEI to meet its responsibilities effectively including Information Systems, Energy Supply and Resource Development, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources, Environment, Health and Safety, and Corporate.

1.2.2 FEFN Background

FEI's operations in FEFN consist of a transmission lateral from the nearby Spectra Energy processing plant to the town of Fort Nelson, together with a gas distribution system. Also included in the service area is the Prophet River Extension.

The natural gas distribution system in the Fort Nelson area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and other companies and continued as BC Gas Inc., later BC Gas Utility Ltd., then Terasen Gas Inc., and now FortisBC Energy Inc.

FEFN customers have benefited and continue to benefit in various ways from being served by FEI, which is a much larger gas distribution company than FEFN would be on a standalone basis. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities;
- Access to low cost capital funding;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and

- Access to the commodity-related benefits of being in a company that is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs.

FEFN's gas supply has typically been obtained through one contract. For the past number of years, the Company has used a small portion of its contracted gas storage capacity at Aitken Creek to improve the load factor of the Fort Nelson load and to mitigate the impact of gas volatility for Fort Nelson customers. The diversity of FEI's overall gas supply portfolio has assisted over the years in providing favourable gas supply arrangements for FEFN.

1.2.3 Regulatory Context

Rates have been set separately for FEFN from the date the utility was acquired to the present. FEI (as BC Gas Utility Ltd.) sought regulatory consolidation of FEFN with the remainder of the Company in its 1992 Revenue Requirement Application, and again in its 2011 Common Rates, Amalgamation and Rate Design Application, but the adoption of common rates for FEFN was not approved in either of these applications. As such, FEFN is excluded from the common rates that are applicable to the rest of FEI.[4] Therefore, FEFN has been excluded from the Company's general revenue requirement applications and Performance Based Ratemaking (PBR) plans.

The most recent revenue requirement change approved by the Commission was the 2017 and 2018 Revenue Requirement and Rates Application (2017/2018 RRA) on November 29, 2016 with Order G-173-16[5]. In that Order, the Commission approved an increase in rates for FEFN customers effective January 1, 2017 to recover a revenue deficiency of $149 thousand. A further revenue deficiency of $144 thousand was recovered through an increase in rates for FEFN customers effective January 1, 2019. In the RDA Decision earlier this year, the Commission approved new rates and rate structure for FEFN, including unbundling FEFN rates, moving FEFN rates to a flat rate structure, and rebalancing revenue amongst residential, commercial, and industrial customers.

1.3 *APPROVALS SOUGHT*

The Company seeks the following approvals from the Commission, pursuant to Sections 45, 46, 59 to 61, and 89 of the *Utilities Commission Act* (the UCA):

[4] Order G-21-14 in the FEU Application for Reconsideration and Variance on the FEI Common Rates, Amalgamation and Rate Design Application.

[5] The Commission originally approved the revenue requirement changes for 2017 and 2018 per Commission Order G-162-16 on November 9, 2016 for a revenue deficiency of $153 thousand in 2017 and a further $150 thousand in 2018. In the related compliance filing filed on November 23, 2016, FEI requested approval to amend the revenue requirement changes due to adjustments to the shared services fee from FEI to FEFN. The amended revenue requirement was subsequently approved by Commercial Order G-173-16.

- Approval of an interim, refundable delivery rate increase of 4.37 percent effective January 1, 2019, and approval of an interim RSAM Rate Rider of $0.199 per GJ effective January 1, 2019;
- A permanent delivery rate increase of 4.37 percent effective January 1, 2019, to recover the forecast revenue deficiency of $101 thousand in 2019;
- An additional permanent delivery rate increase of 8.24 percent in 2020 to recover the incremental forecast revenue deficiency of $180 thousand in 2020;
- The RSAM rider to be set to $0.199 per GJ (a decrease of $0.192 per GJ compared to 2018) as set out in Section 3.4, Table 3-3 effective January 1, 2019;
- The following deferral account requests as described in Section 8.4.1 and 8.4.2:
    - The creation of a rate base deferral account for the 2019-2020 Revenue Requirement Application costs with an amortization period of two years beginning 2019;
    - To begin amortizing the 2017 Rate Design Application deferral account, as approved in Commission Order G-162-16, in 2019 over a five-year period; and
    - To continue to delay disposition of the non-rate base Fort Nelson First Nations Right-of-Way Agreement deferral account to the next revenue requirement proceeding.
- A CPCN for an extension of FEI's distribution system in FEFN resulting from its purchase of the gas distribution assets from PRFN as described in Section 10, with 53 residential and six commercial properties currently attached to the system.

A draft form of Order sought for interim rates and permanent rates as well as a draft procedural Order are provided in Appendix D.

FEI notes that the approvals sought for FEFN above will be impacted by FEI's 2019-2022 Demand Side Management (DSM) Application. On June 22, 2018, FEI filed its Application for Acceptance of 2019-2022 DSM Expenditures Plan and on July 28, 2018 the Commission set out the regulatory timetable. Approvals sought within the DSM Application include an increase in expenditures, an adjustment of the amount of expenditures allowed as a forecast within FEI's annual rate setting mechanism and a change to the amortization period of DSM expenditures, all of which will impact the 2019 and 2020 forecasts of FEFN within this Application. The regulatory timetable includes FEI's Reply Argument for the DSM Application on November 1, 2018. If a decision is received for the DSM Application in time, FEI will incorporate the DSM Application decision in its evidentiary update or compliance filing to this Application.

1.4 PROPOSED REGULATORY PROCESS

FEI believes that, consistent with past practice, a written hearing process is appropriate for the review of this Application, and proposes the following regulatory timetable:

Table 1-1: Proposed Regulatory Timetable

ACTION	DATE (2018)
Intervener registration deadline	Wednesday, October 10
Commission and Intervener Information Request (IR) No. 1	Wednesday, October 24
FEI Responses to IR No. 1	Monday, November 19
FEI Written Final Argument	Wednesday, December 5
Intervener Written Final Argument	Wednesday, December 19
ACTION	**DATE (2019)**
FEI Written Reply Argument	Wednesday, January 9

Due to the timing of this Application and the regulatory review process, the Commission will be unable to render its decision on the Application for permanent rates in time to be effective January 1, 2019. Therefore, FEI is requesting approval, pursuant to section 89 of the UCA, for interim 2019 rates in FEFN in the Application, effective January 1, 2019.

1.5 ORGANIZATION OF THIS APPLICATION

The remainder of this Application is organized as follows:

- **Section 2** - FEI's 2016 Rate Design Application (RDA) for Fort Nelson Service Area – summarizes the rate design changes approved for FEFN in the RDA Decision, and discusses the impact of the rate design changes on FEFN;
- **Section 3** - Revenue Requirement and Rates – discusses the revenue requirement and proposed rates the Company is requesting;
- **Section 4** - Gas Sales and Demand and Other Revenue – discusses the impact of use rates, customer additions and other factors affecting demand, revenue and margin in the Fort Nelson region;
- **Section 5** - Cost of Gas – discusses the impact of gas costs on total revenue requirement changes;
- **Section 6** - Operating and Maintenance (O&M) Expenses – discusses the labour and non-labour costs required to continue to operating and maintaining service to customers;
- **Section 7** - Taxes – discusses Property and Income Tax;
- **Section 8** - Rate Base and Capital Additions – discusses rate base overall, as well as each of its components including plant additions, deferral accounts and working capital;

- **Section 9** - Financing and Capital Structure – discusses the financing of rate base assets and the debt and equity components of financing;
- **Section 10** - CPCN for the Prophet River Extension; and
- **Section 11** - Financial Schedules.

2. FEI'S 2016 RATE DESIGN APPLICATION FOR FORT NELSON SERVICE AREA

2.1 *INTRODUCTION*

On February 2, 2017, FEI filed a supplemental filing to its 2016 RDA which included the first comprehensive review of FEFN's rate design. As a result of its review, FEI proposed a number of changes to FEFN's rate design, which the Commission approved in its RDA Decision. Although FEI had proposed that the changes to FEFN's rate design would be implemented in 2018, due to the timing of the RDA Decision, the complexity of the changes and to avoid rate increases only two months apart, FEI will implement the RDA Decision for FEFN rates and rate structures on January 1, 2019.

The purpose of this section is to provide an overview of the approved rate design changes and their impacts on FEFN from 2019 onwards. Since the total bill impact, due to both the RDA Decision and to the revenue requirement changes for 2019 and 2020, to be experienced by each Rate Schedule, including Residential, is less than 10 percent in each year for 2019 and 2020, FEI is not proposing any mitigation mechanism to address the total rate impact.

2.2 *OVERVIEW OF FEI'S RATE DESIGN APPLICATION FOR FORT NELSON*

The RDA Decision approved FEI's new rate design, including amendments to the Rate Schedules for the FEFN. The resulting changes for FEFN include:

- Unbundling the different components (commodity, midstream, and delivery) of FEFN's residential, commercial, and industrial rates;
- Replacing FEFN's existing declining block rate structure with a flat rate structure;
- Renaming FEFN's rate schedules to align with FEI's rate schedule naming conventions (Rate 1 to Rate Schedule 1, Rate 2.1 to Rate Schedule 2 and Rate 2.2 to Rate Schedule 3);
- Setting the annual consumption threshold separating small (Rate Schedule 2) and large (Rate Schedule 3) commercial customers at 2,000 GJ per year, down from the existing threshold at 6,000 GJ per year. This threshold is consistent with the threshold used in FEI's other service areas; and
- Rebalancing of revenues to costs amongst residential, commercial, and industrial rates based on a 95 percent to 105 percent R:C ratio range of reasonableness.

As part of FEFN's rate design changes, FEI sets out the RDA Rates for 2018 which were calculated based on the 2018 approved costs from FEFN's 2017/2018 RRA. The 2018 RDA Rates were established to be revenue neutral (i.e. net zero change in total revenues) when compared to the existing 2018 Approved Rates (2018 pre-RDA Rates). However, as explained earlier, while the 2018 RDA Rates were approved for 2018, due to the timing of the RDA Decision, FEI will implement them on January 1, 2019 in conjunction with the proposed changes from the 2019/2020 RRA.

Table 2-1 below shows the comparison between the existing 2018 pre-RDA rates and the 2018 RDA approved rates and rate structure for FEFN. The 2018 RDA approved rates shown in Table 2-1 below are only the rates resulting from the RDA Decision and do not include any changes from this 2019/2020 RRA. Refer to Section 3 for impacts from this 2019/2020 RRA. FEI also notes that the sum of the Commodity Cost Recovery Charge per GJ and the Storage Transport Charge per GJ shown in Table 2-1 below equals the currently approved gas cost recovery charge of $1.571 per GJ. These two charges are shown separately under the RDA approved rates due to the unbundling of FEFN rates approved by the RDA decision. As discussed in Section 5 of this Application, this Application only seeks approval of FEFN delivery rates. The Commodity Cost Recovery Charge per GJ and the Storage and Transport Charge per GJ are reviewed quarterly under separate proceedings.

Table 2-1: Comparison of Existing 2018 (pre-RDA) Rates and 2018 RDA Rates[6]

Existing Rate Schedule Name	New Rate Schedule Name	Existing 2018 (Pre-RDA) Rates		2018 RDA Rates	
Residential					
Rate 1 Option B Domestic Service	Rate Schedule 1 Residential Service	Minimum Charge incl. First 2 GJ/mth ($/Day)	0.5620	Basic Charge ($/Day)	0.3701
		Next 28 GJ/Mth ($/GJ)	5.128	Delivery Charge ($/GJ)	3.512
		Excess over 30 GJ/Mth ($/GJ)	5.026	Commodity Cost Recovery ($/GJ)	1.552
				Storage and Transport Charge ($/GJ)	0.019
Commercial					
Rate 2.1 General Service (Less than 6,000 GJ)	Rate Schedule 2 Small Commercial Service (Less than 2,000 GJ)	Minimum Charge incl. First 2 GJ/mth ($/Day)	1.4390	Basic Charge ($/Day)	1.2151
		Next 298 GJ/Mth ($/GJ)	5.574	Delivery Charge ($/GJ)	3.781
		Excess over 300 GJ/Mth ($/GJ)	5.450	Commodity Cost Recovery ($/GJ)	1.552
				Storage and Transport Charge ($/GJ)	0.019
Rate 2.2 General Service (Over 6,000 GJ)	Rate Schedule 2 Small Commercial Service (Over 2,000 GJ)	Minimum Charge incl. First 2 GJ/mth ($/Day)	1.4390	Basic Charge ($/Day)	3.6845
		Next 298 GJ/Mth ($/GJ)	5.574	Delivery Charge ($/GJ)	3.330
		Excess over 300 GJ/Mth ($/GJ)	5.450	Commodity Cost Recovery ($/GJ)	1.552
				Storage and Transport Charge ($/GJ)	0.019
Industrial					
Rate 3.1 Industrial Service	Rate Schedule 5 General Firm Service	Minimum Delivery Charge per Month ($/Mth)	1,826	Basic Charge ($/Mth)	600
		Delivery Charge First 20 GJ/Mth ($/GJ)	4.522	Demand Charge ($/GJ/Mth)	30.350
		Delivery Charge Next 260 GJ/Mth ($/GJ)	4.201	Delivery Charge ($/GJ)	1.000
		Delivery Charge Excess over 280 GJ/Mth ($/GJ)	3.450	Commodity Cost Recovery ($/GJ)	1.552
		Gas Cost Recovery Charge ($/GJ)	1.571	Storage and Transport Charge ($/GJ)	0.019
Rate Schedule 25 General Firm Transportation Service	Rate Schedule 25 General Firm Transportation Service	Administration Charge ($/Mth)	202	Administration Charge ($/Mth)	39
		Minimum Delivery Charge per Month ($/Mth)	1,826	Basic Charge ($/Mth)	600
		Delivery Charge First 20 GJ/Mth ($/GJ)	4.522	Demand Charge ($/GJ/Mth)	30.350
		Delivery Charge Next 260 GJ/Mth ($/GJ)	4.201	Delivery Charge ($/GJ)	1.000
		Delivery Charge Excess over 280 GJ/Mth ($/GJ)	3.450	Commodity Cost Recovery ($/GJ)	1.552
		Gas Cost Recovery Charge ($/GJ)	1.571	Storage and Transport Charge ($/GJ)	0.019

[6] Both the existing 2018 pre-RDA rates and the 2018 RDA rates shown in the Table 2-1 do not include the RSAM rate rider

In addition to the changes to the rate schedules set out in the table above, the Commission approved the following in the RDA Decision for FEFN:

- Cancellation of rate schedules that have no customers (Rate 1 Option A, Rate 2.4, Rate 3.2, and Rate 3.3);
- The RSAM Rate Rider will be phased-out for Rate Schedule 5 and Rate Schedule 25 for FEFN. The RSAM deferral account records the differences in Use per Customer (UPC) between the actual and forecast for refunding/charging through a rate rider over a two-year period. However, due to the timing of the RDA Decision, the existing Rate Schedule 5 and 25 customers will continue to contribute to the build-up of the RSAM deferral account balance up to the end of 2018 under the previous mechanism, thus attracting the RSAM rate rider for two subsequent years, i.e. 2019 and 2020. For 2019, FEI will continue to calculate the RSAM rate rider as it has in the past (inclusive of Rate Schedule 25 forecast volume). For 2020, FEI is proposing to hold the RSAM rate rider for Rate Schedule 25 at the 2019 level and calculate the RSAM rate rider for Rate Schedule 1, 2, and 3 based on their volumes (excluding Rate Schedule 25 forecast volume). This is because Rate Schedule 25 customers will not be contributing to the build-up of the RSAM deferral account starting in January 1, 2019, therefore, it would not be fair to continue to include the volumes of Rate Schedule 25 in 2020 to calculate the 2020 RSAM rate rider. Beginning in 2021, the RSAM rate rider for Rate Schedule 25 will be removed entirely. Refer to Section 3.4 for the 2019 RSAM rate rider calculation for FEFN;
- A deferral account to record the cost of changes to the billing system for FEFN that is required for the new rate design with an amortization period of five years beginning in 2019. FEI estimated the cost to make the changes to the billing system at approximately $70 thousand. The actual costs will be recorded on a net-of-tax basis. The work will begin in fall of 2018 and is scheduled to complete before the end of 2018 for the effective date of the new rate design on January 1, 2019; and
- Amendments to FEI General Terms and Conditions (GT&Cs) which set out the approved terms and conditions of service provided by FEI, including FEFN. The amendments include changes to the Standard Fees and Charges Schedule which reduced the Application Charge from $25 to $15, and the Returned Payment Charge from $20 to $8. These changes are reflected in the 2019 and 2020 RRA. Refer to Section 4.8 Other Revenue for further details.

2.3 *RATE IMPACT OF THE RDA DECISION FOR FEFN*

In this section, FEI responds to the Commission's direction in the RDA Decision to consider the appropriateness of implementing a mitigation mechanism to address the impact of rate design and rebalancing proposals on FEFN's residential rates in this Application. As explained below, FEI is not proposing any mitigation mechanism to address the rate impact due to the RDA Decision or revenue requirement changes for 2019 and 2020.

Based on the rates as listed in Table 2-1 above and using the 2019 forecast of average Use per Customer (UPC) as set out in Section 4 of this Application, the annual bill impacts due to the 2018 RDA Rates in dollars and in percentages for the average customer by each Rate Schedule are shown below in Table 2-2:

Table 2-2: Annual Bill Impacts for Average Customers due to the RDA Decision[7]

Rate Schedule	UPC (GJ)	2019 Annual Bill ($) at 2018 Pre-RDA Rates	2019 Annual Bill ($) at 2018 RDA Rates	Annual $ Increase	% of Previous Annual Bill
Rate Schedule 1 Residential Service	125	723	771	47	6.55%
Rate Schedule 2 Small Commercial Service	350	2,343	2,317	(26)	(1.10%)
Rate Schedule 3 Large Commercial Service	3,165	18,034	16,857	(1,176)	(6.52%)
Rate Schedule 25 General Firm Transportation Service	41,500	148,199	155,769	7,570	5.11%

As discussed earlier, the 2018 RDA Rates will be implemented on January 1, 2019 in conjunction with the proposed changes from this Application; therefore, the total annual bill impact to be experienced by FEFN customers will be a combination of both the 2018 RDA Rates and the 2019/2020 RRA. Table 2-3 below shows the total annual bill changes in dollars and in percentages for the average customer by each Rate Schedule which include impacts of the RDA Decision, the 2019 and 2020 revenue deficiencies as discussed in Section 3 of this Application, and the proposed changes in the RSAM rate rider for 2019.

Table 2-3: Total Annual Bill Impacts for Average Customers (incl. RDA, RRA, and RSAM)[8]

		2019		2020	
Rate Schedule	GJ	Annual $ Increase	% of Previous Annual Bill	Annual $ Increase	% of Previous Annual Bill
Rate Schedule 1 Residential Service	125	$ 48	6.26%	$ 48	5.80%
Rate Schedule 2 Small Commercial Service	350	$ (18)	(0.71%)	$ 154	6.24%
Rate Schedule 3 Large Commercial Service	3,165	$ (1,271)	(6.60%)	$ 1,041	5.78%
Rate Schedule 25 General Firm Transportation Service	41,500	$ 6,842	4.16%	$ 13,009	7.60%

As shown in Table 2-3 above, the total bill impacts to be experienced by the individual Rate Schedules are less than 10 percent in each year of 2019 and 2020 when combining both the RDA decision and the 2019/2020 Revenue Requirements. As discussed in the RDA Decision, Elenchus Research Associates Inc. (Elenchus), an independent consultant retained by the Commission staff in FEI's 2016 RDA, observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e. 10 percent or more)[9]. Since the total bill impact to be experienced by each Rate Schedule, including Residential, is less than 10 percent in each year for 2019 and 2020, FEI is not proposing any mitigation mechanism to

7 Annual bills shown in Table 2-2 do not include RSAM Rate Rider

8 The 2019 RSAM Rate Rider 5 included in the total bill impact calculations is proposed to be $0.199 per GJ (as outlined in Section 3.4), which is a decrease of $0.192 per GJ from the 2018 RSAM Rate Rider 5 of $0.391 per GJ. For 2020, the RSAM rate rider used for the total bill impact calculation equals the proposed 2019 RSAM Rider 5 rate rider of $0.199 per GJ; therefore the bill impacts represent no change in the RSAM rate rider.

9 Commission Order G-135-18 and Decision, page 57

address the rate impact due to the RDA Decision or to revenue requirement changes for 2019 and 2020.

2.4 POSTAGE STAMP RATES

As the new FEFN rate structure approved in the RDA Decision aligns with the rate structure of the rest of FEI's service areas, it is possible to easily compare the delivery rates between FEFN and the rest of FEI's service areas. Table 2-4 below compares delivery rates for the applicable Rate Schedules between FEFN and the rest of FEI's service areas for 2019 and 2020[10]. Given that there is still a rate impact that would be experienced by FEFN's residential customers from moving to FEI's rates, and that FEI has not yet filed for approval of 2020 rates, FEI is not proposing to postage stamp Fort Nelson rates in this Application.

Table 2-4: Comparison between FEI and FEFN Delivery Rates[11,12]

	FEI Proposed Rate (2019)	Fort Nelson Proposed Rates (2019)	Difference	FN/FEI	Fort Nelson Proposed Rates (2020)	Difference	FN/FEI
Rate Schedule 1							
Basic Charge/Day	$ 0.3890	$ 0.3701	$ (0.0189)		$ 0.3701	$ (0.0189)	
Delivery Charge/GJ	$ 4.370	$ 3.712	$ (0.658)		$ 4.093	$ (0.277)	
Annual Usage (GJ)	125	125			125		
Effective Rate/GJ	**$ 5.51**	**$ 4.79**	**$ (0.71)**	(13%)	**$ 5.17**	**$ (0.33)**	(6%)
Rate Schedule 2							
Basic Charge/Day	$ 0.8161	$ 1.2151	$ 0.3990		$ 1.2151	$ 0.3990	
Delivery Charge/GJ	$ 3.523	$ 3.996	$ 0.473		$ 4.435	$ 0.912	
Annual Usage (GJ)	349	349			349		
Effective Rate/GJ	**$ 4.38**	**$ 5.27**	**$ 0.89**	20%	**$ 5.71**	**$ 1.33**	30%
Rate Schedule 3							
Basic Charge/Day	$ 4.3538	$ 3.6845	$ (0.6693)		$ 3.6845	$ (0.6693)	
Delivery Charge/GJ	$ 2.939	$ 3.492	$ 0.553		$ 3.821	$ 0.882	
Annual Usage (GJ)	3,164	3,164			3,164		
Effective Rate/GJ	**$ 3.44**	**$ 3.92**	**$ 0.48**	14%	**$ 4.25**	**$ 0.80**	23%
Rate Schedule 25							
Admin Charge/Mth	$ 78.00	$ 39.00			$ 39.00		
Basic Charge/Mth	$ 587.00	$ 600.00			$ 600.00		
Demand Charge/GJ/Mth	$ 20.077	$ 31.785	11.708		$ 34.449	14.372	
Delivery Charge/GJ	$ 0.825	$ 1.053	0.228		$ 1.141	0.316	
Contract Demand	293	293			293		
Annual Usage (GJ)	41,500	41,500			41,500		
Effective Rate/GJ	**$ 2.72**	**$ 3.93**	**$ 1.21**	45%	**$ 4.24**	**$ 1.53**	56%

[10] FEI proposed no rate increase in 2019 in FEI's Annual Review for 2019 Delivery Rates, dated August 3, 2018. Since FEI's rates are reviewed on an annual basis while FEFN's rates proposed in this application is for both 2019 and 2020, therefore, comparison between FEI and FEFN is to FEI's proposed 2019 rates only.

[11] The effective rates in GJ of each Rate Schedule is based on the 2019 forecast of average UPC in GJ for Fort Nelson. Refer to Section 4 for the FEFN's 2019 UPC forecast of each Rate Schedule

[12] FEI's proposed 2019 rates used for the comparison between FEI and FEFN's delivery rate is before the changes to FEI's rates as a result of the RDA Decision.

As shown above, the proposed Fort Nelson residential customers' effective delivery rate for 2019 and 2020, including the impact of the RDA Decision and the 2019/2020 RRA, continues to be lower than FEI's residential customers' delivery rates. However, the effective delivery rates for commercial and industrial customers will be higher than FEI's commercial and industrial customers. For instance, commercial customers in Fort Nelson with annual consumption less than 2,000 GJ (Rate Schedule 2, formerly Rate 2.1) will have effective delivery rates approximately 20 percent and 30 percent higher than FEI in 2019 and 2020, respectively; commercial customers with annual consumption greater than 2,000 GJ (Rate Schedule 3, formerly Rate 2.2) will have effective delivery rates approximately 14 percent and 23 percent high than FEI in 2019 and 2020, respectively; and industrial customers in Fort Nelson under Rate Schedule 25 will have effective delivery rates 45 percent and 56 percent higher than FEI in 2019 and 2020, respectively.

2.5 *CONCLUSION*

This section summarized the changes and impacts to FEFN due to the RDA Decision for FEI. FEI is not proposing any mitigation mechanism to address the rate impact as a result of the RDA Decision since the total bill impact for all customer classes including residential is less than 10 percent in each year for 2019 and 2020 when accounting for both the RDA Decision and the 2019/2020 RRA.

3. REVENUE REQUIREMENTS AND RATES

3.1 *INTRODUCTION*

The purpose of this section is to provide an overview of the total revenue requirements and rates for the forecast periods of 2019 and 2020. Supporting discussion can be found in Sections 4 through 10, with financial schedules provided in Section 11.

FEI notes that the revenue requirements and delivery rate changes for FEFN to be discussed in this section for 2019 and 2020 are based on the 2018 RDA Rates for FEFN only. Refer to Section 2 of this Application for overview of the RDA Decision and changes from existing 2018 (pre-RDA) rates to the approved 2018 RDA Rates for FEFN.

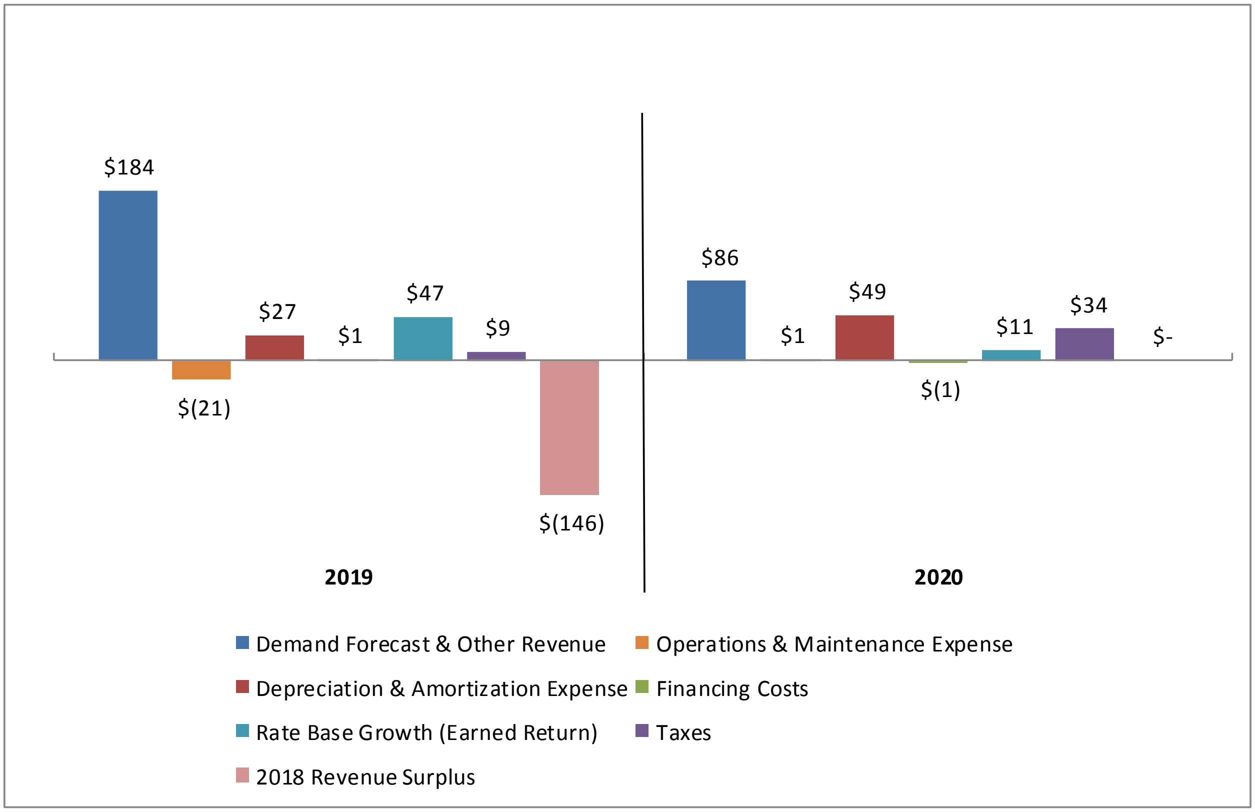
The revenue requirement for FEFN is $3,146 thousand in 2019 (Section 11, Schedule 21, Line 11, Column 5) and $3,201 thousand in 2020 (Section 11, Schedule 22, Line 11, Column 5). This results in an approximate 4.37 percent increase to the delivery rates in 2019 and an additional increase of 8.24 percent to delivery rates in 2020 (cumulative increase of 12.61 percent) when compared to the 2018 RDA Rates approved in the RDA Decision. For a typical FEFN residential customer consuming an average of 125 GJ per year, this equates to an increase to the annual bill from the 2018 RDA Rates of approximately $25 (or 3.05 percent)[13] in 2019 and an additional increase of $48 (or 5.80 percent) in 2020.

3.2 *REVENUE DEFICIENCY*

FEI is forecasting a total revenue deficiency of $101 thousand in 2019 (Section 11, Schedule 1, Line 27, Column 3) and an additional $180 thousand in 2020 (Section 11, Schedule 1, Line 27, Column 5) for a cumulative deficiency of $281 thousand (Section 11, Schedule 1, Line 27, Column 7) in FEFN when compared to the revenues for the same forecast energy demand of each year but at the 2018 RDA Rates approved by the RDA Decision. These deficiencies are summarized in Figure 3-1 below.

[13] Does not include the reduction of RSAM Rate Rider, which is approximately a reduction of $0.192 per GJ in 2019 (refer to Section 3.4). If RSAM Rate Rider is included, the increase from the 2018 RDA Rates to the annual bill is approximately $1 (or 0.06 percent) in 2019 for the average residential customer consuming approximately 125 GJ per year. Note that for 2020, the RSAM Rate Rider is equal to the 2019 RSAM Rate Rider, therefore, the annual bill increase in 2020 remains at $48 (or 5.80 percent).

Figure 3-1: FEFN Revenue Deficiency in 2019 and 2020 (amounts in $ thousands)



As displayed in Figure 3-1 above, the largest contributor to the overall revenue deficiency over the two years of 2019 and 2020 is the reduction in the customer demand forecast and, to a lesser extent, depreciation and amortization expenses as well as rate base growth. In 2019, these increases are partially offset by the ending of any amortization of the 2017 revenue deficiency, as it was fully amortized in 2018.

3.2.1 Demand Forecast and Revenue at the 2018 RDA Rates

The Demand Forecast discussed in Section 4 is used to determine the revenue surplus or deficiency. The 2018 RDA Rates are applied to the demand forecast to determine the variance (surplus or deficiency) between revenues at the 2018 RDA Rates and the revenue requirement for the test years. The decrease in demand in both 2019 and 2020 is mostly attributed to the continuing trend of decline in the use rate per customer for both residential Rate Schedule 1 and commercial Rate Schedule 2. Additionally, the residential customer class is experiencing a steady decline of customer counts in recent years which decreases the demand and this trend is forecasted to continue in 2019 and 2020. The reduced demand contributes approximately $184 thousand to the revenue deficiency in 2019 and to an incremental revenue deficiency of $86 thousand in 2020. As noted above, the decrease in forecast demand is the largest driver of the revenue deficiency over the Test Period.

3.2.2 Operations and Maintenance Expense

The impact of changes in O&M is a decrease to the revenue requirement by $21 thousand in 2019 and an incremental increase to the revenue requirement by $1 thousand in 2020 (cumulative decrease of $20 thousand), net of capitalized overhead. The items contributing to the O&M amounts are discussed more fully in Section 6.

3.2.3 Depreciation and Amortization Expense

The $27 thousand net increase in depreciation and amortization expense in 2019 is comprised of a net $41 thousand increase in depreciation expense ($14 thousand of which relates to additions to Distribution Plant in 2018 and $15 thousand of which relates to upgrades to the Fort Nelson office building) partially offset by a net $14 thousand decrease in amortization expense for a number of deferral accounts.

The incremental $49 thousand increase in depreciation and amortization expense in 2020 is comprised of a net $44 thousand increase in amortization expense for a number of deferral accounts.

3.2.4 Taxes

As discussed in Section 7, forecast levels of property taxes, changes in income tax rates, changes to capital cost allowances (CCA) rates, and changes in earned return and taxable income all have an impact on the revenue deficiency.

Property tax is forecast to decrease by approximately $18 thousand in 2019 due to a decrease in the assessed value of assets, and then increase by approximately $7 thousand in 2020 due to growth in revenues and corresponding grants in-lieu taxes.

There is an increase of $27 thousand in 2019 and a further increase of $27 thousand in 2020 (cumulative increase of $54 thousand over the Test Period) in income taxes, driven by increases in earned return and taxable income in the two years.

3.2.5 Earned Return and Financing Costs

Changes in the amount of rate base affect the amount of return on the rate base. The rate base has increased from $11,228 thousand in 2018 to $11,932 thousand in 2019 (Section 11, Schedule 2, Line 23) and to $12,108 thousand in 2020 (Section 11, Schedule 3, Line 23). This contributes $47 thousand to the revenue deficiency in 2019 and an additional $11 thousand in 2020 (cumulative $58 thousand over the Test Period).

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 9. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Over the two-year Test Period, there is no net impact due to changes in interest rates and the ratio between long-term and short-term financing (net $1 thousand increase in 2019 which is offset by a net $1 thousand decrease in 2020).

3.3 DELIVERY RATES

Based on the net revenue deficiency over the Test Period, FEI is seeking an increase of 4.37 percent in 2019 to FEFN's delivery rates approved as part of the 2018 RDA Rates, with an additional increase of 8.24 percent in 2020, for a cumulative increase of 12.61 percent over the two-year Test Period. For a typical FEFN residential customer consuming an average of 125 GJ per year, this equates to an increase of approximately $25 (or 3.05 percent) in 2019 and an additional increase of $48 (or 5.80 percent) in 2020 when compared to the 2018 RDA Rates. Table 3-1 below summarizes the annual bill impacts in dollar and in percentage for the average customer by each Rate Schedule due to the 2019 and 2020 revenue deficiencies.

Table 3-1: Annual Bill Impacts for Average Customers due to Revenue Deficiency (RRA) Only[14,15]

		2019		2020	
Rate Schedule	GJ	Annual $ Increase	% of Previous Annual Bill	Annual $ Increase	% of Previous Annual Bill
Rate Schedule 1 Residential Service	125	$ 25	3.05%	$ 48	5.80%
Rate Schedule 2 Small Commercial Service	350	$ 75	3.07%	$ 154	6.24%
Rate Schedule 3 Large Commercial Service	3,165	$ 513	2.83%	$ 1,041	5.78%
Rate Schedule 25 General Firm Transportation Service	41,500	$ 7,240	4.21%	$ 13,009	7.60%

As discussed in Section 2 of this Application, FEI will implement the RDA Decision for FEFN on January 1, 2019 which coincides with the propose increase due to the revenue deficiencies as discussed above in this section. Table 3-3 below summarizes the total annual bill impacts in dollars and in percentage for the average customer by each Rate Schedule when all changes are combined. This includes the impacts of the RDA Decision, the 2019 and 2020 revenue deficiencies, and the proposed changes in the RSAM rate rider for 2019 (as it sets out in Section 3.4 below). Refer to Appendix B for detail calculations of the annual bill impact in dollars and in percentage for an average customer by each Rate Schedule.

[14] Please note that the average annual use rates for each rate category that are used to calculate the bill impacts have been updated to reflect current customer use rates. Please refer to Section 4.5 for more information.

[15] Calculated using commodity rates effective January 1, 2018 as approved by Commission Order G-173-17 and still in place at July 1, 2018. The annual bill impacts to Rate Schedule 25 appear higher than other rate schedules because this is a Transportation Service rate schedule, and therefore only the delivery portion of the annual bill is included in the calculation.

Table 3-2: Total Annual Bill Impacts for Average Customers (incl. RDA, RRA, and RSAM) [16, 17]

		2019		2020	
Rate Schedule	GJ	Annual $ Increase	% of Previous Annual Bill	Annual $ Increase	% of Previous Annual Bill
Rate Schedule 1 Residential Service	125	$ 48	6.26%	$ 48	5.80%
Rate Schedule 2 Small Commercial Service	350	$ (18)	(0.71%)	$ 154	6.24%
Rate Schedule 3 Large Commercial Service	3,165	$ (1,271)	(6.60%)	$ 1,041	5.78%
Rate Schedule 25 General Firm Transportation Service	41,500	$ 6,842	4.16%	$ 13,009	7.60%

FEI does not have any customers served under Rate Schedules 5 and 6 in FEFN.

3.4 *RSAM*

Order G-17-04, dated February 5, 2004, granted approval for the implementation of the RSAM account for FEFN to capture variations in the delivery margin (Revenue less Cost of Gas) for residential, commercial and industrial rate classes. Order G-17-14 subsequently approved a change in the amortization period for the RSAM account from three years to two years. The RSAM account accumulates the annual RSAM debits and credits with one half of the net balance being recovered or refunded in the following year via a rate rider.

The RSAM rate rider for 2019 has been calculated consistent with past practice at $0.199 per GJ effective January 1, 2019 as shown in Table 3-3 below (a decrease of $0.192 per GJ from the 2018 rider). In the fourth quarter of 2019, FEI will recalculate the rate rider for FEFN to reflect 2018 actual information as well as updated projections for 2019, and accordingly will file for approval of a revised RSAM rate rider effective January 1, 2019 if necessary.

[16] The 2019 RSAM Rate Rider 5 included in the total bill impact calculations is proposed to be $0.199 per GJ (as outlined in Table 3-3 below), which is a decrease of $0.192 per GJ from the 2018 RSAM Rate Rider 5 of $0.391 per GJ. For 2020, the RSAM rate rider used for the total bill impact calculation equals the proposed 2019 RSAM Rider 5 rate rider of $0.199 per GJ; therefore the bill impacts represent no change in the RSAM rate rider. The 2020 RSAM rate rider will be recalculated at the end of 2019 except for Rate Schedule 25 which will remain at the 2019 level. Refer to Section 3.4 for detail.

[17] The 2020 total bill impact is due to the 2020 revenue deficiency only, hence the 2020 bill impacts are the same between Table 3-1 and Table 3-2. This is because the changes due to RDA is a one-time adjustment in 2019 and the RSAM rate rider is equal to the RSAM rate rider in 2019 as discussed in Footnote #16 above.

Table 3-3: 2019 RSAM Rate Riders

2018 RSAM + Interest Closing Balance ($000)	147
Amortization Period (years)	2
2019 Amortization post-tax ($000)	74
Tax Rate	27%
2019 Amortization pre-tax ($000)	101

RSAM (Rider 5) Calculation			
Rate Class	**RSAM Amortization ($000)**	**2019 Volume (TJ)**	**Rider ($/GJ)**
Rate 1		243.9	0.199
Rate 2.1		160.1	0.199
Rate 2.2		61.0	0.199
Rate 25		41.3	0.199
	101	506.3	0.199

As approved in the RDA Decision, the RSAM will be phased-out for Rate Schedule 5 and 25 for FEFN. As the RDA Decision will not be implemented until January 1, 2019, the existing Rate Schedule 5 and 25 customers will continue to contribute to the build-up of the RSAM deferral account balance up to the end of 2018, thus attracting the RSAM rate rider for two subsequent years, i.e. 2019 and 2020, until the 2018 balance is fully recovered. For 2019, FEI will continue to calculate the RSAM rate rider as it has in the past (inclusive of Rate Schedule 25 forecast volume). For 2020, FEI is proposing to hold the RSAM rate rider for Rate Schedule 25 at the 2019 level and calculate the RSAM rate rider for Rate Schedule 1, 2, and 3 based on their volumes (excluding Rate Schedule 25 forecast volume). This is because Rate Schedule 25 customers will not be contributing to the build-up of the RSAM deferral account starting in January 1, 2019, therefore, it would not be fair to continue to include the volumes of Rate Schedule 25 in 2020 to calculate the 2020 RSAM rate rider. Beginning in 2021, the RSAM rate rider for Rate Schedule 25 will be removed entirely.

4. GAS SALES AND DEMAND, AND OTHER REVENUE

4.1 *INTRODUCTION*

This section responds to previous Commission directions to provide information on FEI's demand forecast for FEFN, describes the forecast demand from FEFN residential, commercial and industrial customers over the Test Period, calculates the forecast revenue of FEFN at the 2018 RDA Rates (refer to Section 2 of this Application) based on the forecast total energy demand, and sets out the forecast of Other Revenue. As described in detail below, FEI's natural gas demand forecast for FEFN is based upon methods that are consistent with those used in prior years, and provides a reasonable estimate of natural gas demand for the Test Period of 2019 and 2020. FEI is forecasting a decrease in consumption in FEFN for both 2019 and 2020 when compared to the 2018 Approved demand. The total normalized demand is forecast to be approximately 506 TJ in 2019 and 482 TJ in 2020, which is a decrease of 54 TJ in 2019 and 78 TJ in 2020 from the 2018 Approved level of 560 TJ. Based on the 2018 RDA Rates for FEFN at each customer class, FEI's 2019 revenue and gross delivery margin forecasts for FEFN are $3.045 million and $2.313 million, respectively. For 2020, FEI's revenue and gross delivery margin forecasts for FEFN based on the 2018 RDA Rates are $2.920 million and $2.228 million, respectively.

The remainder of this section is organized as follows:

- Section 4.2 – Response to Commission Directive re: Demand Forecast
- Section 4.3 – Overview of Forecast Methods
- Section 4.4 – Customer Additions
- Section 4.5 – Use Rate (Residential and Commercial Customers)
- Section 4.6 – Demand Forecast
- Section 4.7 – Revenue and Delivery Margin Forecast
- Section 4.8 – Other Revenue

In addition to the sections described above, FEI has included the following appendices related to the demand forecast:

- Appendix A1 – Conference Board of Canada Report

  Provides the data and source for the BC Housing Starts that are utilized in FEI's residential demand forecast for FEFN.

- Appendix A2 – Historical Forecast and Consolidated Tables

  Provides historical forecast and actual data as well as variances of historical forecasts, broken down by customer classes. Based on the 10 years of data shown in Appendix

A2, Section3, Table A2-3, the 10-year mean average percentage error of the demand forecast is 2.9 percent for residential and 6.6 percent for the aggregate commercial rate classes. For 2017, the most recent year with actual data, the demand forecast error for the residential rate class was 4.2 percent and for aggregate commercial rate classes was 2.2 percent.

- Appendix A3 – Forecast Method

  Provides a detailed description of FEI's demand forecast methods for FEFN, including supporting calculations for the residential and commercial use per customer and customer additions forecasts.

4.2 RESPONSE TO COMMISSION DIRECTIVE RE DEMAND FORECAST

In Order G-162-16 dated November 9, 2016 regarding FEI's Application for 2017 and 2018 Revenue Requirement and Rates for FEFN, the Commission directed FEI as follows:

> 7. FortisBC Energy Inc. is directed to file the supporting calculations for the residential and small commercial use per customer and customer additions forecasts in its future revenue requirement applications for the Fort Nelson service area.

FEI has included the requested information in this Application in Appendix A3 Demand Forecast Method.

4.3 OVERVIEW OF FORECAST METHODS

Consistent with the forecasting process followed by FEI for its other service areas, the forecast demand is comprised of three main components:

- Customer additions (account) forecast;
- Average use per customer (UPC) forecast; and
- Industrial Forecast.

The residential and commercial energy forecast, consisting of customers served under Rate Schedules 1, 2, and 3[18], is driven by the respective account and use per customer forecasts. Consistent with the methodology used across FEI's other service areas, the average use per customer is estimated for customers served under Rate Schedules 1, 2, and 3 and then is multiplied by the corresponding forecast of customers in each rate class to derive energy consumption.

[18] Rate Schedule 1 represents Residential customers. Rate Schedules 2 and 3 are both Commercial customer rate schedules (with the same applicable delivery rates) and the delineation between Rate Schedule 2 and 2 is based on an annual demand of 2,000 GJs. Rate Schedule 25 is for large volume firm transportation customers.

The industrial energy forecast reflects the forecast demand based on an interview with the one remaining industrial customer in FEFN under Rate Schedule 25.

Current approved 2018 RDA Rates, based on the FEFN rate design approved in Order G-135-18 as discussed in section 2 of this Application, are applied against the energy forecast to calculate the forecast revenue. The cost of gas is subtracted from this forecast revenue to calculate the delivery margin (also referred to as gross margin), which is used as part of the calculation of the revenue deficiency for the Test Period.

The subsequent sections set out the results of the demand forecasts. In the figures provided in the subsequent sections below, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. The 2019 and 2020 Revenue Requirements for FEFN are based on actual data up to and including 2017; the latest calendar year for which full actual data exists is the 2017 calendar year.
- 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 filing. For example, for this Application the Seed Year is 2018 and the Seed Year forecast is based on the latest actual years, including 2017. As such, the 2018 Seed Year forecast in this Application will differ from the 2018 Forecast presented in the 2017/2018 RRA, for which 2017 actual data was not available.
- 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 an Annual Review) or a range of two or more years depending on the filing (two years, 2019 and 2020, for FEFN).

4.3.1 Implications of the Rate Design Decision on the Demand Forecast

With the approval of FEI's 2016 RDA for FEFN (refer to Section 2 of this Application), for the Test Years of 2019 and 2020, the commercial customers in FEFN will be taking service under Rate Schedules 2 and 3 (rather than the previous Rates 2.1 and 2.2) with a separation point of 2,000 GJ per year (rather than the previous 6,000 GJ per year). FEI's forecast methods require historical demand, including the 2018 seed year, to be based on the same rate schedules as the forecast years. Therefore, in order to develop the commercial forecast for 2019 and 2020, FEI mapped the commercial customers in FEFN to the new Rate Schedules 2 and 3 for the period from 2014 to 2017 using their average annual weather normalized consumption of those years. Customers with an average annual consumption of 2,000 GJs or less were mapped to Rate Schedule 2 while customers with an average annual consumption greater than 2,000 GJs were mapped to Rate Schedule 3. Refer to Appendix A2, Table A2-1 for the Customer Count, Customer Additions, Use per Customer and Total Energy Demand in the previous Rate 2.1 and 2.2 commercial classes for 2014 to 2017 and Table A2-2 for the respective mapped numbers in the new Rate Schedules 2 and 3 commercial classes over the same period.

4.4 *CUSTOMER ADDITIONS*

The forecast of customer accounts is the first component of determining the total energy demand.

The Conference Board of Canada (CBOC) housing starts forecast provides a proxy for Fort Nelson's residential customer additions. The year over year growth rate is calculated for 2019 to 2020 based on the CBOC Provincial Medium Term forecast on January 19, 2018, Table 156 and Table 157. The CBOC Provincial Medium Term forecast is provided in Appendix A1.

The commercial additions forecast is based on the average of the actual additions recorded between 2014 and 2017.

The industrial customer base in FEFN is limited to one customer, and FEI is not forecasting a change during the Test Period.

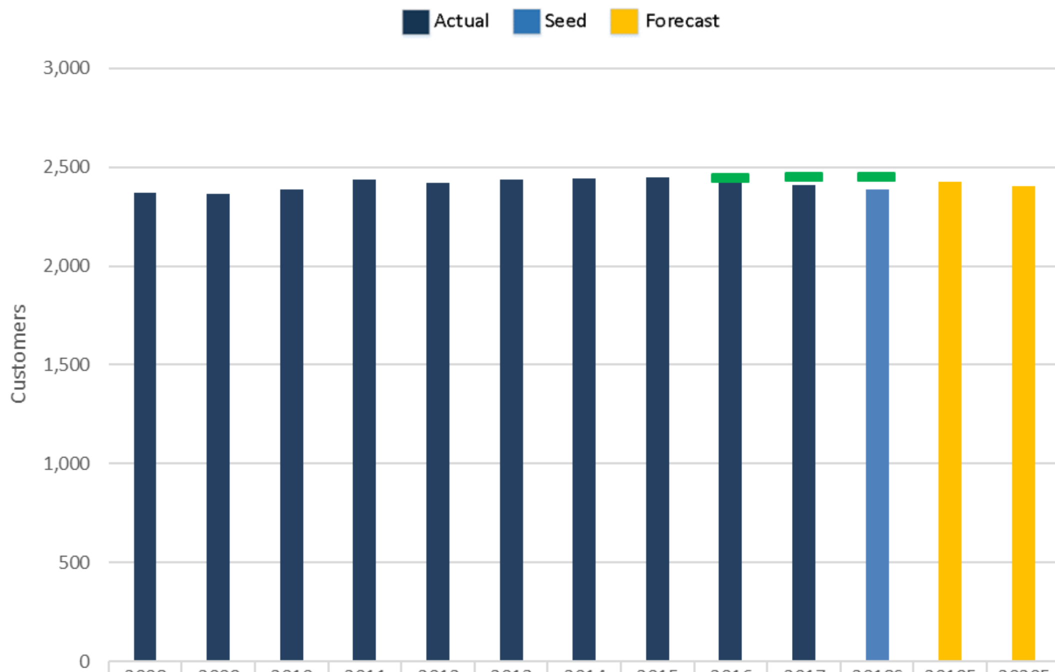
See Appendix A3 for a more detailed description of FEFN's customer additions forecast method.

To be discussed in Section 10, FEI is seeking a CPCN as part of this Application for the Prophet River Extension. If the CPCN is approved, FEI will proceed to install new meters in 2019 at the premises of all residential and commercial customers in PRFN. Currently, PRFN is a single large commercial customer. As a result of FEI's distribution asset extension to include PRFN and installing individual meters, this single large commercial customer will be removed and converted to 53 new residential customers in Rate Schedule 1, and six new commercial customers in Rate Schedule 2. The customer additions, use per customer and demand forecasts for 2019 and 2020 discussed throughout this section include this change. Furthermore, for the purposes of developing the forecast, these rate switches were mapped into FEFN's new rate structure as discussed in Section 4.3.1 above.

Figure 4-1 below shows the total number of customers in the residential, commercial and industrial segments[19].

[19] 2018 data in the figures represents projected year end customers.

Figure 4-1: Total Customers

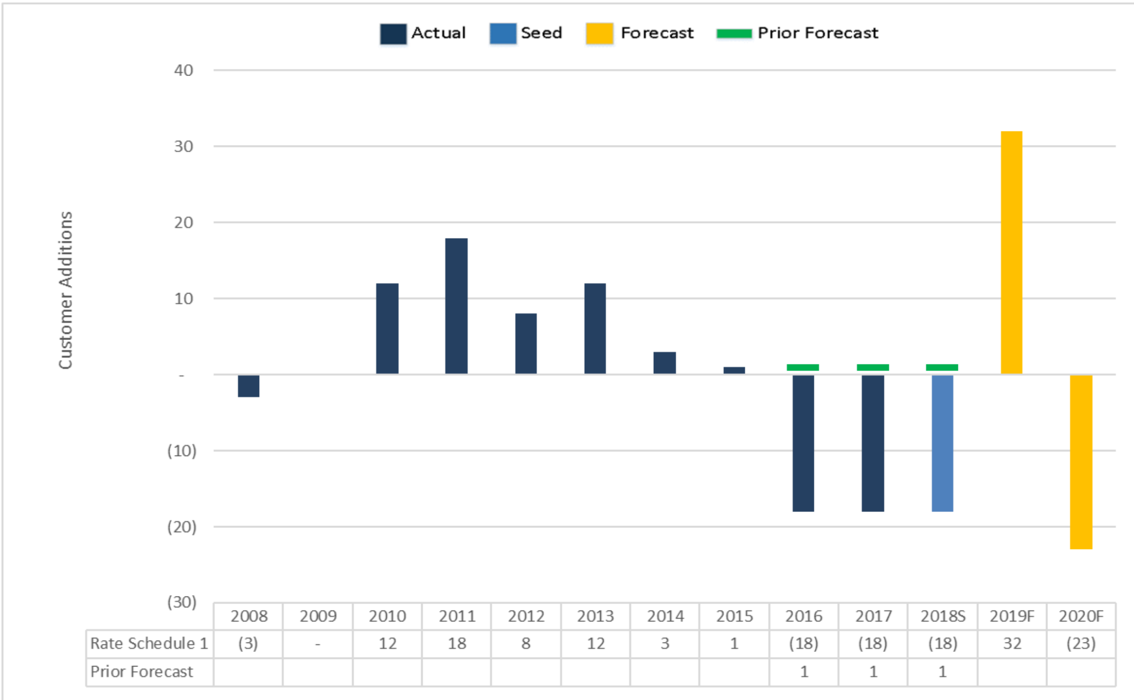


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Total Customers	2,369	2,367	2,388	2,435	2,423	2,438	2,441	2,446	2,432	2,410	2,386	2,426	2,406
Prior Forecast									2,449	2,452	2,455		

4.4.1 Residential Customer Additions

As shown in Figure 4-2 below, FEFN has experienced negative net customer additions in both 2016 and 2017. In the absence of the Prophet River Extension, and based on the CBOC forecast, FEFN would have forecasted a further loss of 18 customers in 2019. However, the addition of 53 customers from PRFN temporarily reverses the trend in 2019. In 2020, the forecast is once again based solely on the CBOC predictions and the net additions are forecast to be negative.

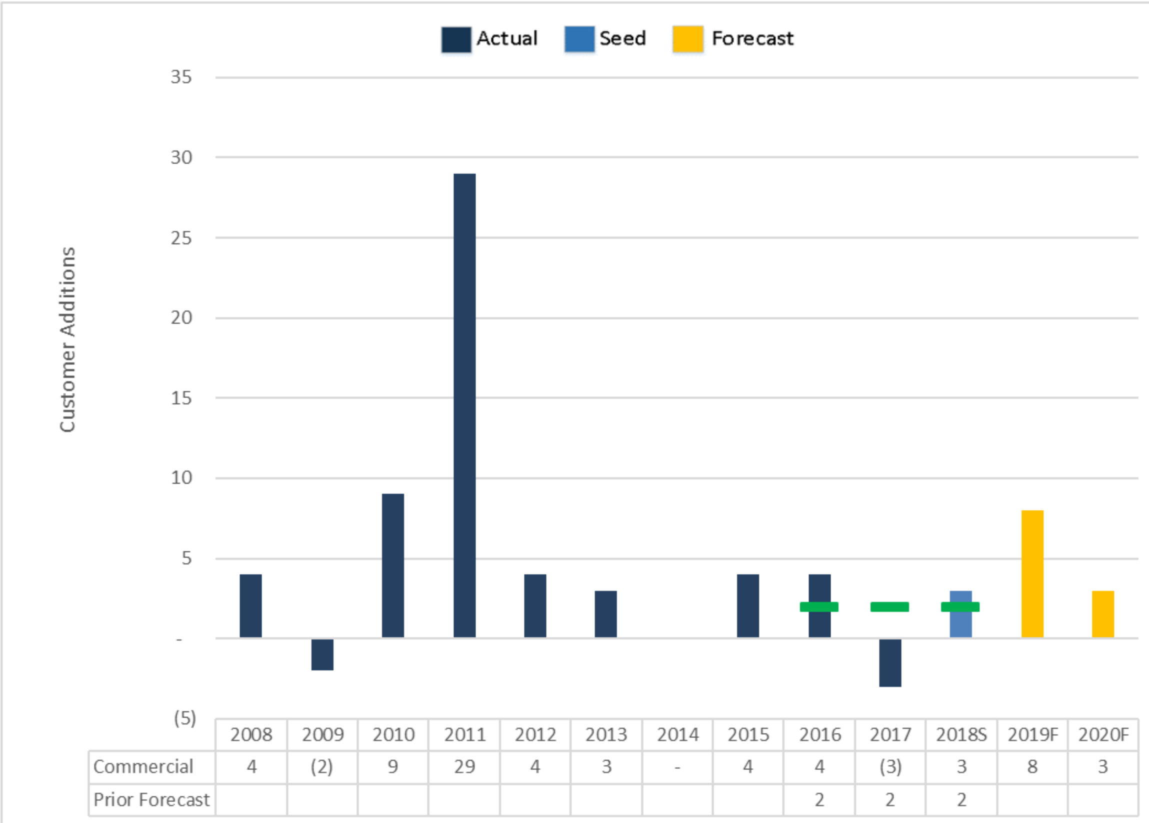
Figure 4-2: Residential Customer Additions



4.4.2 Commercial Customer Additions

Without the Prophet River Extension, the commercial customer additions forecast was for three customers per year in each of 2018S, 2019F and 2020F. For 2019F, a one-time adjustment was made for the Prophet River Extension: six customers were added to Rate Schedule 2 and one customer was deducted from Rate Schedule 3, resulting in a net one-time addition of five customers in 2019. When combined with the base forecast of three additions, the result is eight additions in 2019F as shown in Figure 4-3 below.

Figure 4-3: Commercial Customer Additions

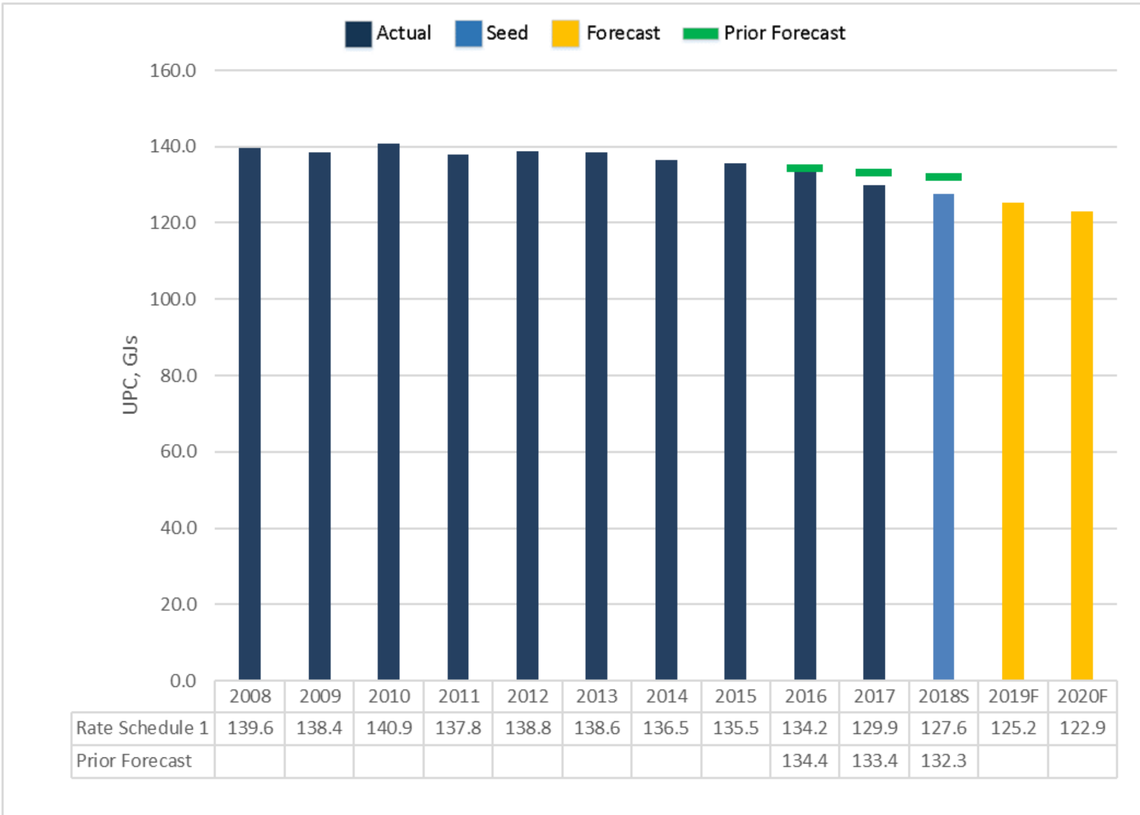


4.5 *USE RATES (RESIDENTIAL AND COMMERCIAL CUSTOMERS)*

FEI developed individual UPC forecasts for each rate schedule by considering the recent (three year) historical weather-normalized use per account. See Appendix A3 for a more detailed description of FEI's UPC forecast methods.

The Rate Schedule 1 UPC is forecast to continue to decline through the Test Period as seen in Figure 4-4 below.

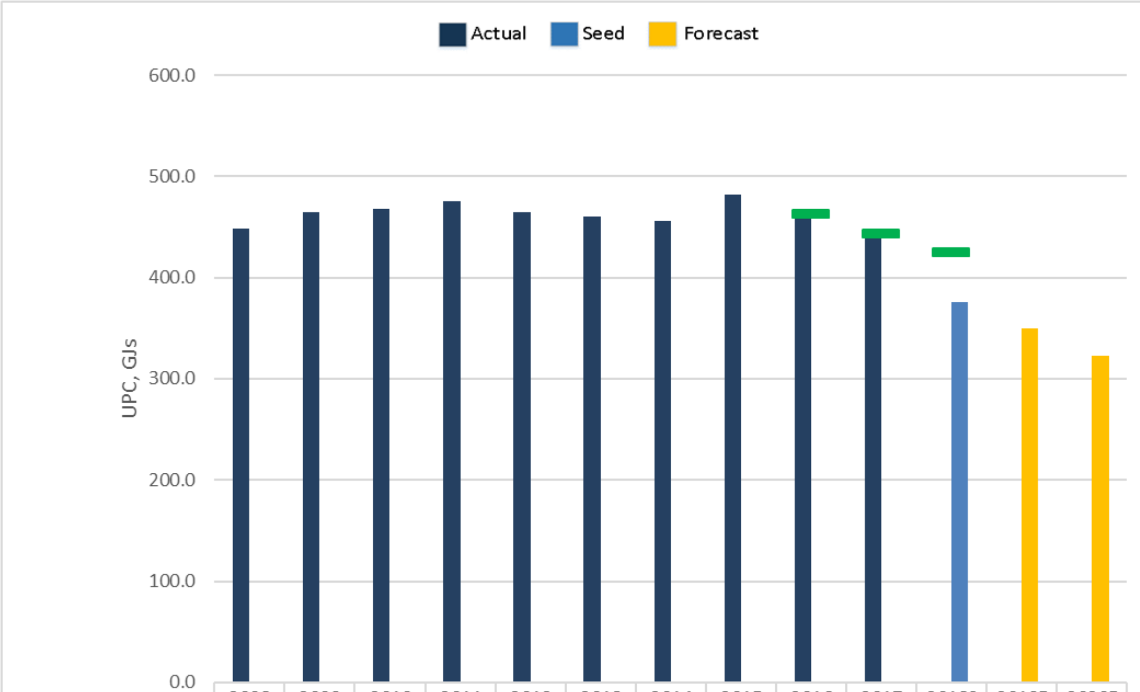
Figure 4-4: Residential UPC for Rate Schedule 1



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 1	139.6	138.4	140.9	137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	125.2	122.9
Prior Forecast									134.4	133.4	132.3		

For small commercial, the UPC of Rate Schedule 2 (formerly Rate 2.1) has been declining steadily since 2015 as shown in Figure 4-5 below. The recently approved rate design for FEFN will result in 16 customers being moved out of Rate Schedule 2 and into Rate Schedule 3 (formerly Rate 2.2). This move will effectively lower the average UPC for the customers remaining in Rate Schedule 2, from approximately 447.8 GJ to 375.9 GJ. Note that the UPC shown in Figure 4-5 for years 2008 to 2017 are actual UPCs under the previous Rate 2.1 while the UPCs for the 2018 seed year and the forecasts for 2019 and 2020 are shown as Rate Schedule 2.

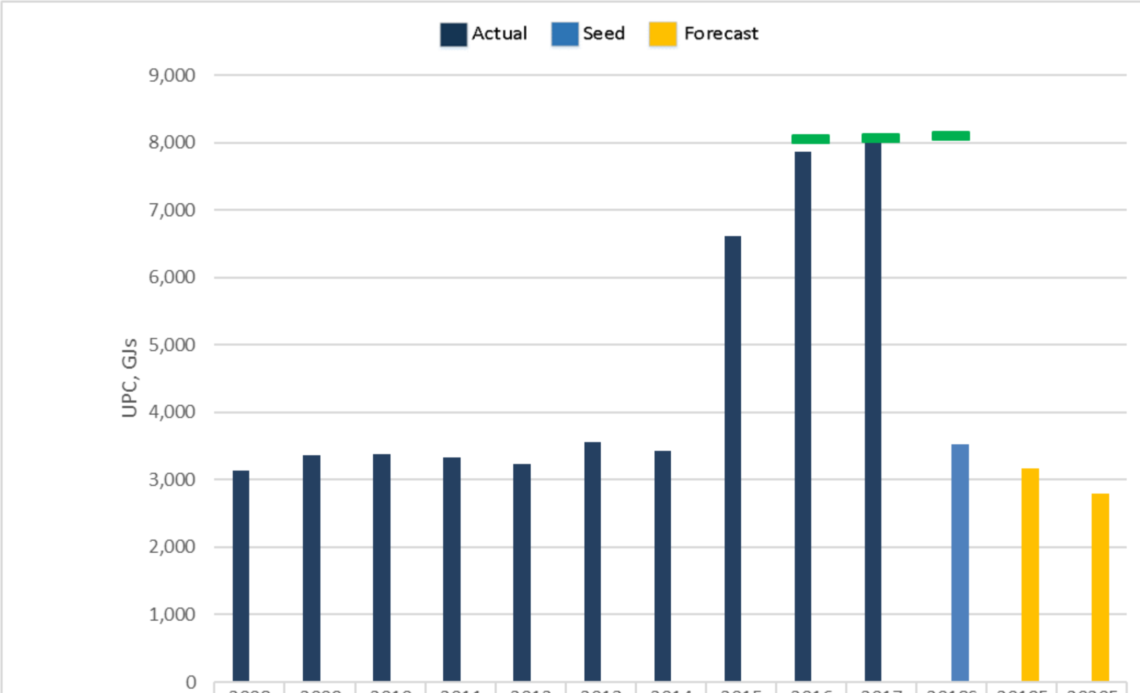
Figure 4-5: UPC for Rate Schedule 2



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 2.1	448.9	464.0	468.1	475.6	465.0	460.2	455.5	482.0	465.8	447.8			
Rate Schedule 2											375.9	349.3	322.7
Prior Forecast									463.1	444.2	425.4		

The Rate Design decision will result in 16 customers migrating from Rate Schedule 2 (formerly Rate 2.1) into Rate Schedule 3 (formerly Rate 2.2). The UPC for these customers is less than the customers currently in Rate Schedule 3, so the result is a reduction in the average UPC for Rate Schedule 3 from approximately 8,086 GJ to 3,526 GJ as shown in Figure 4-6 below. Note that the UPC shown in Figure 4-6 for years 2008 to 2017 are actual UPCs under the previous Rate 2.2 while the UPCs for the 2018 seed year and the forecasts for 2019 and 2020 are shown as Rate Schedule 3.

Figure 4-6: Commercial UPC for Rate Schedule 3



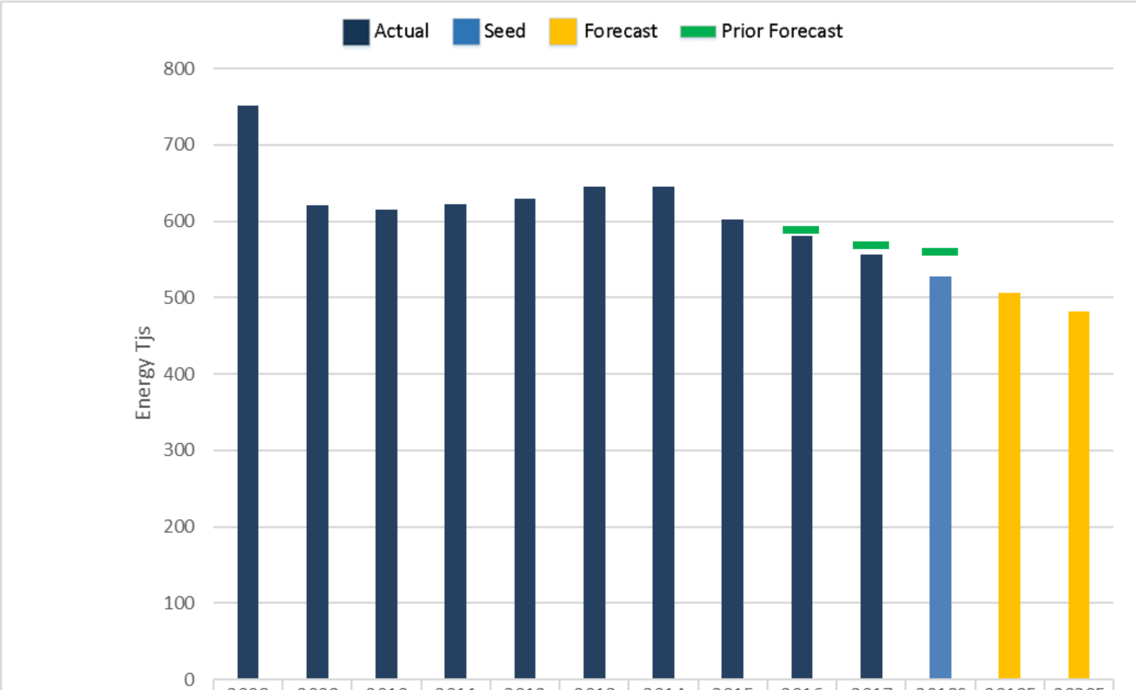
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 2.2	3,137	3,371	3,388	3,326	3,228	3,555	3,425	6,616	7,869	8,086			
Rate Schedule 3											3,526	3,164	2,802
Prior Forecast									8,060	8,081	8,103		

4.6 *DEMAND FORECAST*

The energy demand forecast for each residential and commercial rate schedule is derived by multiplying the total forecast customers, including customer additions, by the average UPC forecast for each rate schedule. As discussed below, the forecast of energy demand from FEFN's remaining industrial customer is based on an interview with the key account manager (identical to the annual industrial survey distributed to other FEI industrial customers). The total forecast energy demand is the sum of the energy demand for the individual rate schedules.

The following Figure 4-7 illustrates the total historical and forecast normalized energy demand over the period 2008 to 2020. FEI is forecasting a decrease in FEFN's total energy demand for 2019 and 2020 as compared to 2018S, as well as a decrease compared to the Approved 2018 total energy demand of 560 TJs (Section 11, Schedule 23, Line 9, and Column 2).

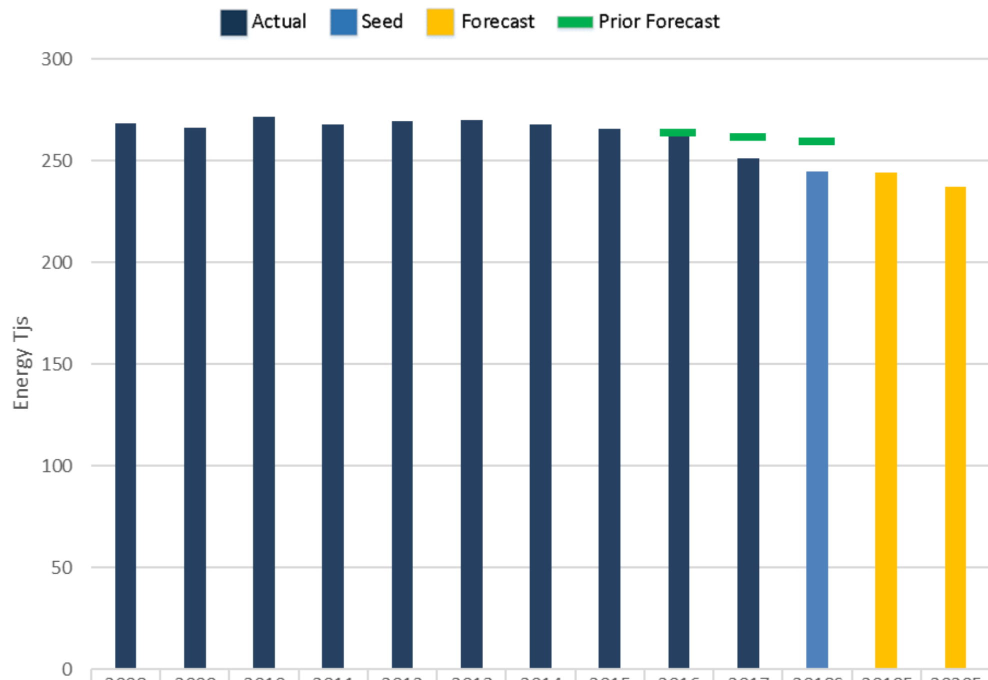
Figure 4-7: Total Energy Demand



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Total	751	621	615	622	630	645	645	603	580	556	527	506	482
Prior Forecast									590	570	560		

As seen in Figure 4-8 below, FEI is forecasting a minimal change in residential energy demand in FEFN from 2018 to 2019, but a greater decrease from 2019 to 2020. The minimal change in 2019 is primarily due to the expectation of an additional 53 Rate Schedule 1 customers from the PRFN Extension, as discussed in Section 4.4. The increase offsets the CBOC-based forecast of a decrease of 22 customers in 2019, as well as the continuing decline in the residential use rate as shown in Section 4.4.1.

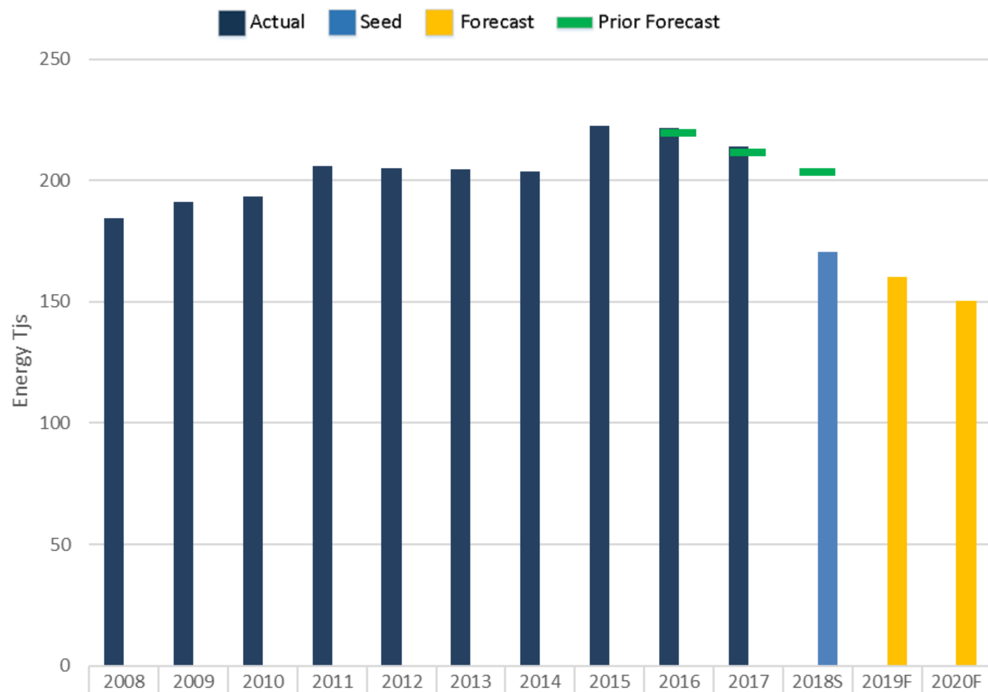
Figure 4-8: Residential Energy Demand



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 1	268	266	271	268	269	270	268	265	262	251	245	244	237
Prior Forecast									264	262	260		

As seen in Figure 4-9 below, the forecast demand for Rate Schedule 2 is decreasing. This decrease in demand is the result of declining use rates, which is partially offset by stable customer growth. The large decrease in 2018S compared to the approved forecast is due to the recently approved changes to FEFN's rate design, which lowered the use rate forecast for Rate Schedule 2 as discussed in Section 4.5.

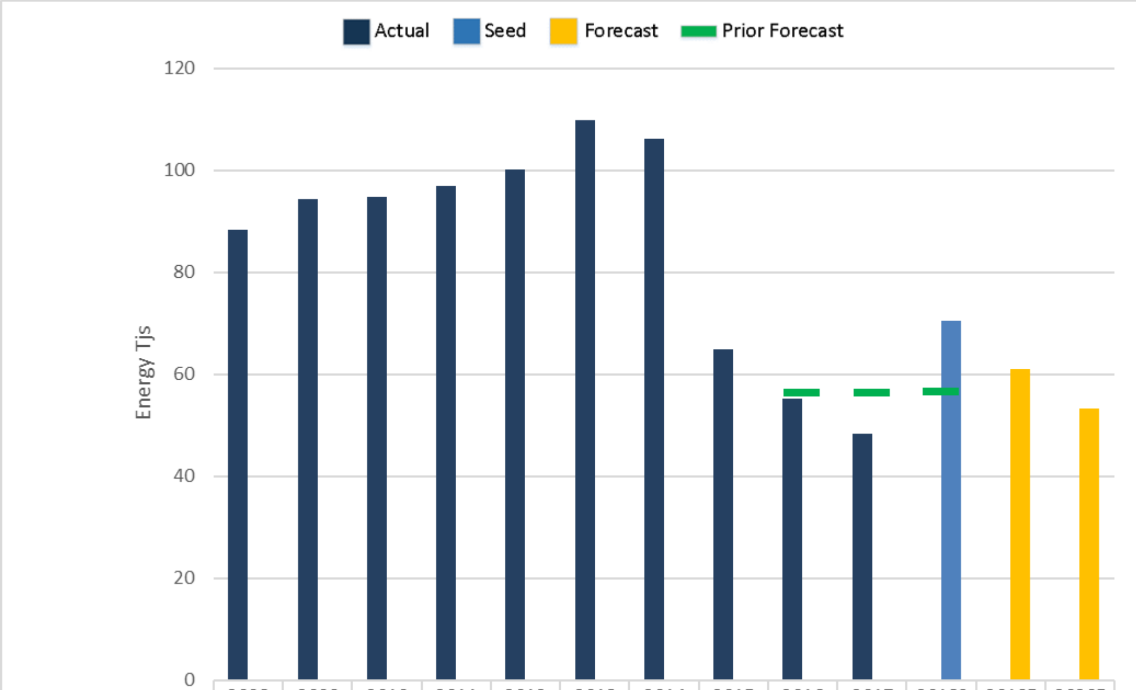
Figure 4-9: Rate Schedule 2 Energy Demand



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 2.1	185	191	194	206	205	204	204	223	222	214			
Rate Schedule 2											171	160	150
Prior Forecast									220	212	204		

Figure 4-10 below shows the forecast demand for Rate Schedule 3. The forecast reflects the new lower use rate for Rate Schedule 3 along with the increase in customers that were moved from Rate Schedule 2 due to the approved changes to FEFN's rate design.

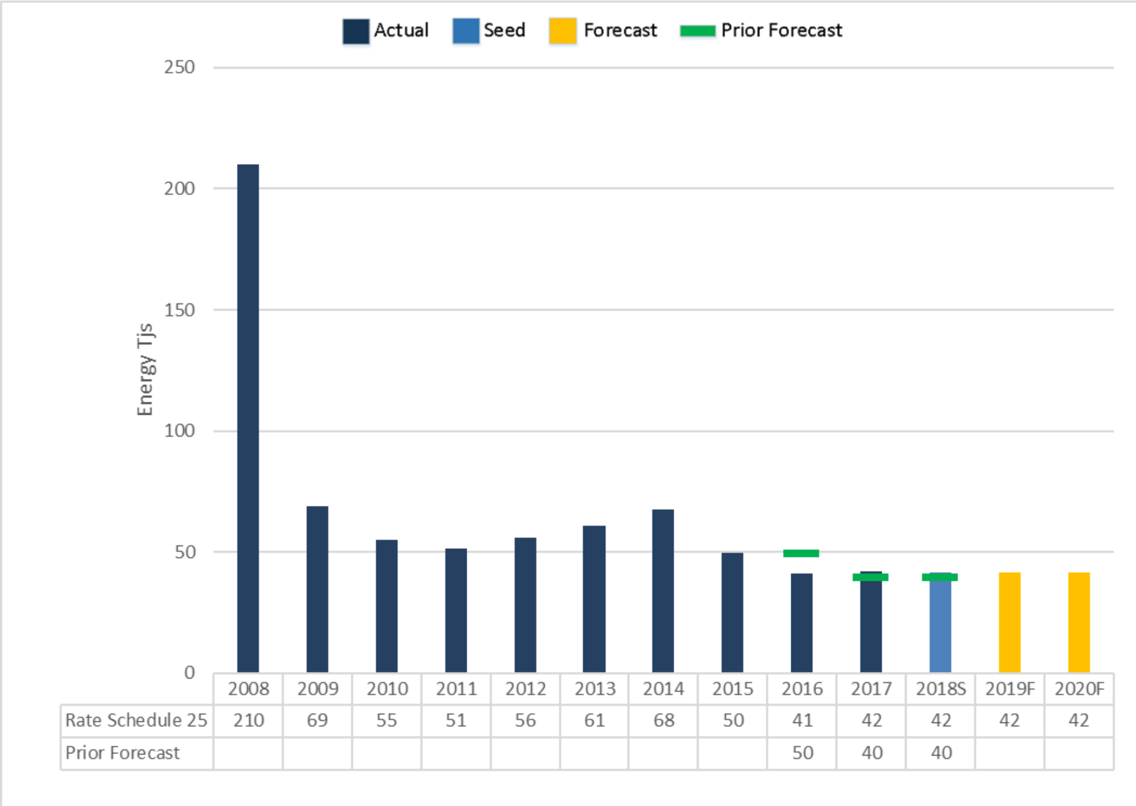
Figure 4-10: Rate Schedule 3 Energy Demand



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F	2020F
Rate Schedule 2.2	88	94	95	97	100	110	106	65	55	48			
Rate Schedule 3											71	61	53
Prior Forecast									56	57	57		

FEI only has one Industrial customer served under FEFN's Rate Schedule 25. In 2008, this customer stopped production from its two facilities in Fort Nelson but the facilities remained to be open and consumed natural gas for space heating. In November 2016, this customer closed one of its two facilities with the remaining one continuing to consume natural gas for space heating only. The future forecast of energy demand is based on this industrial customer's own forecast, as established during an interview with a key account manager. The Industrial Energy Demand is seen in Figure 4-11 below.

Figure 4-11: Industrial Energy Demand



4.7 REVENUE AND DELIVERY MARGIN FORECAST

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEFN has developed its forecast of revenues by applying the total energy forecast to the approved 2018 RDA Rates for each rate schedule.

Table 4-1 below summarizes the revenues projected for 2018 and forecast for 2019 and 2020, based on the approved 2018 RDA Rates.

Table 4-1: Forecast Sales Revenue[20]

Revenue ($ thousands)	Actual 2017	Projected 2018	Forecast 2019	Forecast 2020
Residential[1]	1,520	1,414	1,504	1,465
Commercial[2]	1,714	1,570	1,385	1,299
Industrial[3]	146	156	156	156
Total	**3,380**	**3,140**	**3,045**	**2,920**

[20] The cost of gas was lower in 2018 as compared to 2017, and this is reflected in the decreased revenue in 2018 projected numbers.

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2 for 2017 Actual and 2018 Projected; Rate Schedule 2 and 3 for 2019 and 2020 Forecasts
3. Rate Schedule 25

The delivery margin is the forecast of revenues at the approved 2018 RDA Rates, minus the cost of gas (discussed in Section 5). Table 4-2 below summarizes the delivery margin projected for 2018 and forecast for 2019 and 2020, by customer segment, at the approved 2018 RDA Rates.

Table 4-2: Forecast Delivery Margin

Margin ($ thousands)	Actual 2017	Projected 2018	Forecast 2019	Forecast 2020
Residential[1]	1,022	1,030	1,120	1,093
Commercial[2]	1,158	1,179	1,037	979
Industrial[3]	138	155	156	156
Total	**2,318**	**2,364**	**2,313**	**2,228**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2 for 2017 Actual and 2018 Projected; Rate Schedule 2 and 3 for 2019 and 2020 Forecasts
3. Rate Schedule 25

4.8 *OTHER REVENUE*

There are three components of Other Revenue, as shown in Section 11, Schedules 35-36, Lines 1-3:

- Late Payment Charges;
- Connection Charges; and
- Other (primarily non-sufficient funds cheque administration fees).

As discussed in Section 2 of this Application, the FEI's 2016 RDA Decision approved amendments to FEI's GT&Cs (including FEFN). The amendments include changes to the Standard Fees and Charges Schedule which reduced the Application Charge from $25 to $15, and the Returned Payment Charge from $20 to $8. These changes are reflected in the 2019 and 2020 Other Revenue forecast as described below.

Table 4-3 below shows the forecast of Other Revenue from FEFN in 2019 and 2020. The 2019 and 2020 Other Revenue forecast is entirely comprised of application charges and late payment charges. Revenue for application and late payment charges have been forecast based on 2017 actual data adjusted proportionally with the forecasted total revenues in 2019 and 2020. It is to be noted the decrease in application charge forecast for 2019 and 2020 is primarily due to reduction in application charge due to the RDA Decision as discussed above.

Table 4-3: 2017-2020 Other Revenue Components ($000s)

	Approved 2017	Actual 2017	Approved 2018	Projected 2018	Forecast 2019	Forecast 2020
Late Payment Charge	17	14	17	13	13	12
Application Charge	9	7	9	8	5	5
Other Recoveries	-	-	-	-	-	-
Total Other Operating Revenue	**26**	**21**	**26**	**21**	**18**	**17**

5. COST OF GAS

This Application only seeks approval of the delivery rates in FEFN. The Company is not requesting approval of forecast gas costs with this Application; rate changes related to the flow-through of gas costs are dealt with in separate applications to the Commission. Any variations between forecast and actual gas costs will continue to be returned to or recovered from customers through the existing Gas Cost Reconciliation Account (GCRA) deferral account mechanism.

While FEI is not requesting approval of forecast gas costs with this Application, the forecast cost of gas, which includes the estimated cost of unaccounted for gas (UAF), is required in the determination of a number of revenue requirement line items that form part of the forecasts included in the Application. The forecast cost of gas sold is determined by multiplying forecast sales volumes by the existing (as of July 1, 2018) gas cost recovery charge for each rate schedule; for FEFN, the gas cost recovery charge is the same for all sales rate schedules.

The current gas cost recovery charge is $1.571 per GJ, approved by Commission Order G-175-17, dated November 30, 2017 and became effective January 1, 2018. The 2018 First Quarter Gas Cost Report for Fort Nelson, filed on March 7, 2018, and the 2018 Second Quarter Gas Cost Report for Fort Nelson, filed on June 6, 2018, recommended the gas cost recovery rate remain unchanged at April 1, 2018 and at July 1, 2018, respectively. Commission Letter L-6-18, dated March 15, 2018, and Letter L-11-18, dated June 15, 2018, accepted the Company's recommendations to leave the gas cost recovery charge unchanged from $1.571 per GJ.

Consistent with established Commission practice, FEI will continue to review and report on the gas costs and the gas cost recovery rates for FEFN on a quarterly basis and, as necessary, will make application for any rate changes to recover the cost of gas.

As discussed in Section 2 of this Application, the Commission approved FEI's 2016 Rate Design Application with Commission Order G-135-18 on July 20, 2018, which includes a new unbundled (commodity, midstream, and delivery), flat rate structure for FEFN. The new unbundled flat rate structure, beginning January 1, 2019, will show a separate Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule and a separate Storage and Transport per Gigajoule charge for each rate schedule, instead of using a combined gas cost recovery charge as is embedded in the current declining block rate structure. In its 2018 Fourth Quarter Gas Cost Report, FEI will apply for the unbundled Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule and the Storage and Transport per Gigajoule charge to be effective January 1, 2019 for each rate schedule. FEI notes that all revenues discussed in this Application are based on the currently approved gas cost recovery charge of $1.571 per GJ as discussed above.

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use; UAF includes measurement variances and cannot be projected with precision. Consistent with past practice, the forecast UAF is based on the historical five-year rolling average of the actual annual UAF for FEFN. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered via the gas cost recovery charge, whereas the cost of UAF related to the Transportation Service Rate Schedule 25 is included in the determination of the delivery rates.

6. OPERATING AND MAINTENANCE EXPENSES

6.1 *INTRODUCTION*

FEI has forecasted its operating and maintenance expenses (O&M) for 2019 and 2020 as part of determining its revenue requirements. The O&M expenses included in this Application are required to continue to serve customers in a safe and efficient manner. In 2019, O&M expenses are forecast to decrease by approximately 2.3 percent from 2018 Approved primarily due to lower labour costs, employee expenses, and facilities costs. In 2020, O&M expenses are forecast to remain relatively unchanged from the 2019 Forecast.

6.2 *DETERMINATION OF O&M*

To determine the FEFN-related total O&M costs, both actual and forecast, the following process is used:

1. Determine the FEFN direct O&M costs. These costs consist of labour for the two employees noted below, vehicle usage, and materials and services used in direct system operations.
2. Allocate O&M costs from those FEI departments that provide functional support to FEFN. These shared services costs include charges related to Information Systems, Energy Supply and Resource Development, Transmission, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources, Environment, Health and Safety, and Corporate (shown as "Fees and Administration Costs" in Table 6-1 below).

   Starting with 2008, the Commission approved the use of customers as the allocation factor to determine the Shared Services for FEFN, stating[21]:

   > Shared Services received by TG Fort Nelson from TGI for 2008 are to be allocated to the Company on the basis of customers…

   Since that time, the Shared Services allocation has been based on FEFN's customers as a percentage of FEI's customers.

   The combined customer total for FEI and FEFN is forecast to be 1,027,385 for 2019 and 1,039,093 for 2020, while the FEFN portion is 2,423 and 2,409 (as shown in the financial schedules in Section 11, Schedules 27 and 28, Line 15, and Column 9). Therefore, the allocation factors which have been used for 2019 and 2020 proposed rates are 0.236% and 0.232% respectively.

   The 2019 and 2020 O&M costs used in the allocation are consistent with the basis used in calculating the approved 2017 and 2018 shared services fee. The calculation uses the gross O&M FEI is forecasting for 2019, taking into consideration the formula drivers

[21] Order G-27-08

approved under the PBR as well as the forecast of the O&M items that are excluded from the formula calculation. The amount is then escalated for inflation in 2020.

3. Apply an overhead capitalization rate to the sum of the direct and allocated O&M costs to calculate the net O&M costs. The currently approved overhead capitalization rate is 12 percent.

6.3 FORECAST O&M

Table 6-1 below provides a combined resource view of the direct and allocated O&M costs for the years 2017 through 2020. The O&M forecasts for 2019 and 2020 were determined in accordance with the methodology described above.

Table 6-1: O&M Resources Required for FEFN ($ thousands)

Particulars	2017 Approved	2017 Actual	2018 Approved	2018 Projected	2019 Forecast	2020 Forecast
M&E Costs	$ 19	$ 25	$ 19	$ 18	$ 19	$ 19
IBEW Costs	330	132	338	364	327	331
Labour Costs	**349**	**157**	**357**	**382**	**346**	**350**
Vehicle Costs	44	22	45	43	44	45
Employee Expenses	29	13	30	20	20	20
Materials and Supplies	8	8	8	8	8	8
Fees and Administration Costs	526	495	536	508	540	535
Contractor Costs	21	20	21	21	21	22
Facilities	41	32	42	34	36	37
Recoveries & Revenue	(2)	(2)	(2)	(2)	(2)	(2)
Non-Labour Costs	**667**	**588**	**680**	**632**	**667**	**665**
Total Gross O&M Expenses	**1,016**	**745**	**1,037**	**1,014**	**1,013**	**1,015**
Less: Capitalized Overhead	(122)	(122)	(124)	(124)	(121)	(122)
Total O&M Expenses	**$ 894**	**$ 623**	**$ 913**	**$ 890**	**$ 892**	**$ 893**

Major changes in Gross O&M line items are discussed below:

6.3.1.1 Total Labour Costs

The Operations staffing at FEFN includes two full-time IBEW employees supported periodically by specialized pressure control technicians and management staff in Prince George. The IBEW labour costs are forecast to be slightly lower in 2019 and 2020 compared to 2018 Approved. FEFN staff turnover has been reduced and the higher training costs (time charged to training) incurred in prior years are anticipated to return to normal levels. In addition, certain processes have been streamlined resulting in less required support from Prince George IBEW staff in 2019 and 2020.

The 2017 Actual is lower compared to 2017 Approved, primarily due to an IBEW employee being on medical leave worth approximately $40 thousand, an amount of approximately $70 thousand for standby labour that was inadvertently excluded from the 2017 O&M, and lower than anticipated maintenance activities undertaken.

The 2018 Projected includes a true-up of $70 thousand for 2017 Actual standby labour. Excluding this amount, the 2018 Projected is forecast to be lower than the 2018 Approved as one of the full-time IBEW employees was cross training in other areas outside of Fort Nelson during the first half of the year.

6.3.1.2 Employee Expenses

The 2019 and 2020 employee expenses are forecast to be the same as 2018 Projected. The 2018 Projected is lower than 2018 Approved due to lower than expected requirements for travel-related training for the two full-time IBEW employees and reduced Prince George Operations management team travel to FEFN. The 2017 Actual employee expenses are lower than 2017 Approved primarily due to an IBEW employee being on medical leave and reduced management team travel to FEFN.

6.3.1.3 Facilities

These are costs to operate and maintain the local office including janitorial and telephone services as well as line heater fuel for the distribution station. The 2017 Actual and 2018 Projected costs are lower than 2017 and 2018 Approved costs primarily due to lower line heater fuel costs.

6.3.1.4 Fees and Administration Costs

For 2019, of the $540 thousand forecasted fees and administration costs, $528 thousand is the shared service fee, approximately $1 thousand is related to FEFN's allocation of FEI's 2019-2022 DSM Expenditures application costs, and approximately $8 thousand is related to the legal fees for the purchase of the Prophet River Extension and the remainder is for miscellaneous administration expenses. Please refer to Section 10 for further details related to the Prophet River Extension. The 2019 forecast shared service fee is increased by $24 thousand from the 2018 Projected amount of $504 thousand.

For 2020, of the $535 thousand forecasted fees and administration costs, $531 thousand is the shared service fee, which is a further $3 thousand increase from the 2019 forecast.

Table 6-2 provides a detailed breakdown of the 2019 and 2020 shared service fee calculation.

Table 6-2: FEFN Shared Service Fee ($ thousands)

	2019 Forecast	2020 Forecast
FEI Gross O&M [1]	279,811	285,961
Less: O&M not subject to allocation [2]	56,143	57,255
O&M Allocation Base	223,667	228,706
Multiplied by Allocation Factor	0.00236	0.00232
Shared Services Fee	528	531
Average Number of Customers		
FEFN	2,423	2,409
FEI	1,024,962	1,036,685
Total	1,027,385	1,039,094
Allocation Factor (FEFN/Total)	0.00236	0.00232

[1] The 2019 Forecast Gross O&M from Section 11, Schedule 20 of the 2019 FEI Annual Review.
[2] Distribution common costs that do not provide functional support to Fort Nelson and accounted for as direct costs.

The 2017 Actual and 2018 Projected costs are lower than 2017 and 2018 Approved due to a decrease in the shared service allocation factor from 0.244 percent to 0.236 percent due to a lower percentage of FEFN customers.

6.4 *SUMMARY*

The forecast amounts of O&M for the years 2019 and 2020 included in this Application are based on appropriate forecasting methodologies and the planned and required activities for the test years. FEI's forecast of O&M expenses in FEFN are required to continue to operate the FEFN natural gas distribution system and to meet the needs of customers.

7. TAXES

7.1 INTRODUCTION

This section discusses FEI's forecasts of property taxes and income tax for FEFN, which have been forecast on a basis consistent with prior years. In 2019, property taxes are forecast to decrease by 13 percent from 2018 Approved and then increase by 6 percent in 2020. Income tax is forecast to increase by 36 percent compared to 2018 Approved and then a further increase of 26 percent in 2020. Any variances from the forecast of property taxes included in rates will be recorded in the Property Tax deferral account and returned to or collected from customers in the following year.

7.2 PROPERTY TAX

Details of 2017 and 2018 approved, actual and projected property tax expense, and the forecasts for 2019 and 2020 can be found in Table 7-1 below.

Table 7-1: Property Tax Expense ($000)

Asset Type	Approved 2017	Actual 2017	Approved 2018	Projected 2018	Forecast 2019	Forecast 2020
Transmission Assets	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.5
Distribution Assets	80.4	77.3	82.5	73.4	74.9	77.0
General Assets	20.9	12.3	21.7	11.6	12.2	12.7
In-Lieu	37.7	37.6	33.2	27.2	31.8	36.2
OGC Fees	1.5	1.4	1.5	1.4	1.5	1.5
Total Property Taxes	$ 140.9	$ 129.0	$ 139.3	$ 114.0	$ 120.8	$ 127.9
Forecast Change from 2018 Approved					(13%)	(8%)
Forecast Change from 2018 Projected					6%	12%

The property taxes for 2018 are projected at $114 thousand which is lower than the 2018 Approved level, primarily due to a reassessment of the inventory in FEFN with BC Assessment which reduced the amount attributed to distribution and general assets and, to a certain extent, the Grants In-Lieu.

For the 2019 Forecast and 2020 Forecast, it is estimated the property tax expenses will be approximately 13 percent and 8 percent lower, respectively, than the 2018 Approved level because of the reassessment. Compared to 2018 Projected, Property taxes are forecast to increase by approximately 6 percent and 12 percent in 2019 and 2020, respectively, primarily due to the forecast increase in revenues resulting in higher in-lieu taxes. 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.

7.3 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating FEFN's revenue requirements. 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. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation.

As approved by Commission Order G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

Income tax for 2019 is forecast to be $102 thousand (Section 11, Schedule 37, Line 13, and Column 3), an increase of 36 percent when compared to 2018 Approved. The increase is primarily due to increase in FEI's taxable income in FEFN as a result of the growth in rate base and increase in depreciation expense. For 2020, the income tax is forecast to be $129 thousand (Section 11, Schedule 38, Line 13, and Column 3), which is an increase of 26 percent from the 2019 forecast level. The increase is primarily due to changes in amortization expenses forecasted between 2019 and 2020.

7.4 *SUMMARY*

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

8. RATE BASE AND CAPITAL ADDITIONS

8.1 INTRODUCTION

The 2019 and 2020 mid-year average rate base amounts of $11,932 thousand and $12,108 thousand respectively, as determined in Section 11, Schedules 2 and 3, reflect the investment by the Company in utility assets necessary to provide service to customers in FEFN.

The table below sets out FEFN's 2017 through 2020 rate base.

Table 8-1: Rate Base (amounts in $000s)

	Approved 2017	Actual 2017	Approved 2018	Projected 2018	Forecast 2019	Forecast 2020
Net Plant in Service, Mid-Year	10,793	11,138	11,019	11,340	11,610	11,894
Adjustment to 13 - Month Average	-	(42)	-	-	-	-
Work in Progress, No AFUDC	35	121	35	121	121	121
Unamortized Deferred Charges	297	376	126	198	130	21
Cash Working Capital	37	30	34	44	44	45
Other Working Capital	14	24	14	27	27	27
Utility Rate Base	$ 11,176	$ 11,648	$ 11,228	$ 11,730	$ 11,932	$ 12,108

The growth in rate base for the forecast period is largely attributable to capital additions. Each of the main components of rate base (plant balances, deferral accounts, and working capital) is discussed separately below.

8.2 NET PLANT IN-SERVICE (NPIS)

The mid-year NPIS balance of $11,610 thousand in 2019 and $11,894 thousand in 2020 per Table 8-1 above is the sum of the mid-year average of the gross plant in-service, contributions in aid of construction (CIAC), and accumulated depreciation and amortization related to these two items.

8.2.1 Gross Plant In-Service (GPIS)

The opening GPIS balance of $16,517 thousand in 2019 (Section 11, Schedule 2, Line 1, Column 3) is made up of ending 2017 GPIS plus 2018 projected plant additions, less retirements. Plant additions are comprised of capital expenditures adjusted for opening and closing work in progress (WIP), plus allowance for funds used during construction and overheads capitalized, where applicable. Table 8-2 below summarizes the plant additions in FEFN for 2017 through 2020.

Table 8-2: Summary of Gross Plant Additions ($000s)[22]

	Approved 2017	Actual 2017	Approved 2018	Projected 2018	Forecast 2019	Forecast 2020
Intangibles	46	74	46	46	28	28
Transmission	75	54	15	15	5	5
Distribution	307	302	388	399	575	463
General	50	50	50	50	41	41
Total	478	480	499	510	649	537

For 2017 and 2018 combined, capital additions were generally in line with amounts approved (Approved was $977 thousand and Actual/Projected is $990 thousand) with a variance of approximately 1.3 percent.

A description of the major changes in plant additions for 2019 and 2020 follows.

8.2.1.1 Intangible Plant

As approved in FEI's Annual Review for 2016 Rates[23], FEI is allocating Intangible capital costs to FEFN as of 2017. The amount of the allocation to FEFN's Intangible Plant in 2019 and 2020 is $28 thousand, related to the purchase and sustainment of System Computer Software.

8.2.1.2 Transmission Plant

The forecast additions to transmission plant in 2019 and 2020 are forecasted to be less than prior years' capital expenditures.

Large projects that were identified and initiated in the period of 2015 and 2016, such as the replacement of transmission pipeline valves (2017 - $169 thousand), are being completed in 2017 and 2018[24].

For 2019 and 2020, there are no significant projects planned with only minor cathodic protection issues intended to be addressed. The forecasted cost of this work is $10 thousand with $5 thousand in 2019 and $5 thousand in 2020.

8.2.1.3 Distribution Plant

Table 8-3 below summarizes the forecast additions to distribution plant in 2019 and 2020:

[22] Table excludes AFUDC and capitalized overhead. The forecast capital additions with AFUDC and capitalized overhead for 2019 and 2020 are $770 thousand and $659 thousand, respectively (Section 10, Schedule 5, Line 38, Column 5 for 2019 and Section 10, Schedule 6, Line 38, Column 5 for 2020)

[23] As discussed in the FEI Annual Review for 2016 Rates and as approved by Commission Order G-162-16 on November 9, 2016, FEI is allocating Intangible Plant costs to FEFN beginning in 2017 and the costs are removed from FEI's Base Capital in the same year.

[24] 2015-2016 Fort Nelson Revenue Requirement Application, Page 30.

Table 8-3: Summary of Capital Additions for Distribution Assets ($000s)

	Forecast 2019	Forecast 2020
Growth related Distribution Capital	23	28
Muskwa Gate Station Telemetry	163	-
Recreation Centre District Station Valve Replacement	-	74
Replacement of Steel Distribution Mains and Services	243	319
PRFN Project	104	-
Misc Sustainment Capital	42	42
Total	575	463

The forecast additions to distribution plant in 2019 and 2020 include:

- Growth related distribution capital (new mains, new services, and new meters) which is forecasted to be $23 thousand in 2019 and $28 thousand in 2020. Growth capital investments are incurred to install gas mains, services and meters to attach new customers;
- Upgrades to the Muskwa Gate Station consisting of telemetry to remotely monitor the operation of the station; a new line heater burner management system with industry standard safety features for achieving regulatory compliance, improving reliability, and combustion efficiency; a new station grounding to meet updated industry standards ($163 thousand in 2019);
- Replacement of an under-rated valve at the Recreation Centre District Station to ensure an adequate safety factor ($74 thousand in 2020);
- The proactive replacement of steel distribution mains and services to address those that are prone to leaks, and due to their location in Fort Nelson, of greater risk to public safety due to longer periods of frozen ground and remoteness from emergency repair personnel ($243 thousand in 2019 and $319 thousand in 2020). These are similar expenditures to those incurred and forecasted for 2017 and 2018;
- Installation of individual gas meters to approximately 59 homes and business in PRFN, relocate services as necessary, and conduct work to ensure the distribution system meets FEI safety standards. The capital cost for this work which is included as part of 2019 capital additions is approximately $104 thousand. This work is depended upon FEI receiving a CPCN approval for the Prophet River Extension. Refer to Section 10 for detail; and
- Other miscellaneous sustainment related distribution capital (distribution system integrity) which is forecasted to be $42 thousand in both 2019 and in 2020.

8.2.1.4 General Plant

The 2019 and 2020 forecasts of capital additions for General Plant is approximately $9 thousand less than the 2018 Approved level. The decrease is mostly due to a reduction in the forecast for hardware and software. The HVAC Hydro chlorofluorocarbons replacement project at the Fort Nelson office building, originally planned for 2017 and 2018, will be completed in 2018. For 2019 and 2020, FEI will complete the roof replacement project for the Fort Nelson office building.

8.2.2 Contributions in Aid of Construction (CIAC)

Gross CIAC is composed of opening contributions plus additions and less retirements throughout the year. There are no CIAC additions forecast for 2019 and 2020, and as such the year end CIAC amounts of $1.3 million in each of 2019 and 2020 (Section 11, Schedule 3, Line 11) are unchanged from the 2017 actual ending balance[25].

8.2.3 Accumulated Depreciation

The rate base of FEFN includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation or amortization expense, and decreased through retirements. Depreciation for 2019 and 2020 has been calculated starting January 1 of the year after the assets are placed in service, which is the currently accepted treatment for FEFN.

The depreciation rates used for 2019 and 2020 are the FEI depreciation rates embedded in the delivery rates approved by Order G-196-17, which are the currently approved rates for 2018.

8.3 *WORK IN PROGRESS*

Consistent with past practice, Work in Progress included in Rate Base represents construction work in progress for projects that are shorter than three months in duration and less than $100 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project. The 2018 Projected, 2019 and 2020 forecasts of Work in Progress with no AFUDC are based on 2017 Actual, which was increased from $35 thousand for 2017 Approved to $121 thousand for 2017 Actual.

[25] Historically, FEFN CIAC additions have been minimal in dollar value and are difficult to predict.

8.4 DEFERRAL ACCOUNTS

On May 3, 2017, the Commission issued its Regulatory Account Filing Checklist[26]. The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the Commission.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 13 and 14, FEI has classified its existing rate base deferral accounts for FEFN in accordance with this classification.

The mid-year balances of the deferral accounts included in rate base are provided in Table 8-4 below.

Table 8-4: Deferral Balances included in Rate Base ($000s)

	Approved 2017	Actual 2017	Approved 2018	Projection 2018	Forecast 2019	Forecast 2020
Forecasting Variance Accounts						
Revenue Stabilization Adjustment Mechanism (RSAM)	168	375	56	253	107	36
Interest on RSAM	2	3	1	5	4	1
Gas Cost Reconciliation Account (GCRA)	(87)	(128)	-	(104)	(22)	-
Property Tax Variance	(1)	(20)	1	(40)	(41)	(24)
Interest Variance	(6)	(9)	(1)	1	1	-
Customer Service Variance Account	(27)	(27)	(11)	(11)	(2)	-
Benefits Matching Accounts						
Energy Efficiency & Convservation (EEC)	54	52	71	82	135	182
2019-2020 Revenue Requirement Application	-	-	-	22	37	15
2017-2018 Revenue Requirement Application	42	12	14	(13)	(14)	-
2015-2016 Revenue Requirement Application	9	9	-	-	-	-
2017 Rate Design Application	69	13	93	19	18	14
2016 Cost of Capital Application	3	3	2	2	1	-
Gains and Losses on Asset Disposition	86	86	74	74	63	52
Net Salvage Provision/Cost	(93)	(71)	(174)	(118)	(203)	(291)
Muskwa River Crossing COS	(58)	(58)	-	-	-	-
Muskwa River Crossing Project Costs	136	136	-	-	-	-
Billing system costs for FEFN Rate changes	-	-	-	26	46	36
Total Mid-Year Deferred Charges in Rate Base	297	376	126	198	130	21

In the following sections, FEI requests approval of one new deferral account for FEFN to capture the costs of this application and proceeding. FEI also provides updates on two existing FEFN deferral accounts.

8.4.1 New Deferral Accounts

FEI is proposing to create the following new deferral account for FEFN discussed below.

[26] Log No. 53608, Appendix B.

Table 8-5 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to deferral accounts for regulatory proceedings generally, and the deferral account requested in sections 8.4.1.1 below.

Table 8-5: Deferral Account Filing Considerations

Item	Consideration	Determination
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests the establishment of one new deferral account to capture the costs related to this application and the related regulatory proceeding.
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 account is a regulatory proceeding cost account, which is 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 the account encompasses the preparation and filing of the relevant regulatory applications and their review by the Commission.
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. FEI considers this to be a more cumbersome, less efficient and less accurate 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.
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

Item	Consideration	Determination
		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). FEI forecasts additions to the deferral account 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 O&M for the purpose of determining forecast O&M Expense in the revenue requirement. See section 8.4.1.1.
d)	any impact on intergenerational equity	Generally FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See section 8.4.1.1. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FEI 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. Regular labour and staff expenses related to regulatory applications are included in forecast O&M Expense.
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 FEI 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 section 8.4.1.1.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).

Item	Consideration	Determination
XI.	Outline a recommended regulatory process for the Commission's review of the application.	Deferral account approvals and disposition are generally determined in revenue requirements proceedings.

8.4.1.1 2019-2020 Revenue Requirement Application

FEI will incur costs in 2018 and 2019 related to the 2019 and 2020 Revenue Requirements and Rates Application for FEFN estimated at approximately $70 thousand (on a pre-tax basis). Costs incurred will consist of legal fees, intervener and participant funding costs, Commission costs, required public notifications, miscellaneous facilities, stationery and supplies costs. Consistent with past practice, FEI requests approval to capture the full costs of this Application for FEFN in this rate base deferral account and to amortize these costs over two years, in 2019 and 2020, which represents the period covered by this Application. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates in the following years.

8.4.2 Existing Deferral Accounts

FEI is providing an update on the following two deferral accounts for FEFN.

8.4.2.1 Fort Nelson First Nations Right-of-Way Agreement

As approved through Order G-97-15, a non-rate base deferral account was created to capture the actual costs incurred to complete the Fort Nelson First Nations Right-of-Way Agreement. Further, the Order also stated that disposition of this deferral account should be requested in FEFN's next revenue requirement proceeding.

As part of the 2017 and 2018 Revenue Requirements and Rates Application and approved through Order G-162-16, FEI proposed to continue to record actual costs in this deferral account and apply for disposition of this account in its next revenue requirement proceeding due to ongoing negotiations in finalizing the agreement.

The 2015 and 2016 Revenue Requirements and Rates Application for FEFN forecasted an original spend of $410 thousand related to securing an updated Right-of-Way Agreement with the Fort Nelson First Nations. As at June 30, 2018, FEI has incurred actuals costs of $111 thousand related to this Agreement. Based on the most recent appraisal available, the remaining fee for a 99 year agreement would be approximately $236 thousand, or a 10 year term prepaid fee at $62 thousand with each subsequent 10 year term fee being determined by appraisal at the time of renewal.

However, as the negotiations in finalizing this agreement are still continuing and there remains uncertainty about the ultimate dollar value to be spent, FEI is proposing to continue to record the actual costs in a non-rate base deferral account for FEFN attracting a weighted average cost of capital return and apply for disposition of this account in a future revenue requirement proceeding. This treatment will ensure that customers only pay for the actual costs incurred related to this agreement.

8.4.2.2 2017 Rate Design Application

As part of the 2017-2018 Revenue Requirements Application, FEI requested approval for a rate base deferral account to capture FEFN's portion of the costs related to the 2017 Rate Design Application.

Commission Order G-162-16 approved the establishment of the 2017 Rate Design Application deferral account. The 2017 Rate Design Application deferral account consists both of direct costs to Fort Nelson customers for administration, pre-application funding for stakeholder groups and Commission costs prior to filing the application, as well as the allocated costs from FEI which represent legal and consultant fees, miscellaneous facilities, Commission costs and Participant Assistance/Cost Award (PACA) reimbursements. The methodology used to allocate costs from FEI is based on the number of FEFN customers as a proportion of the total number of FEI and FEFN customers. As of June 30, 2018, FEI has incurred approximately $25 thousand in direct costs to FEFN and another $2 thousand in costs for FEFN allocated from FEI, with an additional $1 thousand forecasted for the remainder of 2018.

Furthermore, in this Application, FEI is seeking approval to amortize these costs over five years beginning in 2019. This amortization period is appropriate given it is consistent with other recovery periods for regulatory proceeding related costs and FEI expects to file a new COSA study within five years as directed by Commission Order G-4-18.

8.5 *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 and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days, and are supported by a Lead Lag Study. Cash working capital of $73 thousand (Section 11, Schedule 17, Line 2) in 2019 and $74 thousand (Section 11, Schedule 18, Line 2) in 2020 has been added to rate base.

FEI has utilized the lead/lag days for FEFN as approved in Order G-138-14 for FEI.

The next and final step in the calculation of cash working capital is to adjust the cash working capital for the reserve for bad debts and the withholdings from employees. The reserve for bad debts and employee withholdings are calculated based on historical levels.

8.6 *OTHER WORKING CAPITAL*

Other working capital consists of inventories of material and supplies.

The forecast 2019 and 2020 costs for these items have been calculated based on historical levels for inventories. Please refer to Section11, Schedules 17 and 18.

8.7 *RATE BASE SUMMARY*

The rate base amounts that have been forecasted for 2019 and 2020 incorporate required expenditures to meet our customers' needs and make improvements related to system integrity and reliability.

9. FINANCING AND CAPITAL STRUCTURE

9.1 INTRODUCTION

FEI has forecast FEFN's share of FEI's debt financing costs for 2019 and 2020 using the same method as has been accepted in the past. 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. FEFN shares the same capital structure and ROE as FEI. FEI has prepared this Application for FEFN using FEI's approved ROE of 8.75 percent and common equity percentage of 38.5 percent.

9.2 FINANCING COSTS

Debt financing costs include the interest expense on issued debt as well as interest expense on new issuances that are forecast. Debt consists of both Long-term Debt and Short-term (Unfunded) Debt.

9.2.1 Long-Term Debt

FEFN receives an allocation of FEI's total long term debt. As set out in FEI's Annual Review for 2019 Rates application, FEI plans to issue long-term debt of approximately $150 million in 2019. FEI also plans to issue a further $150 million in 2020. Both of these issues will be used to repay existing indebtedness and finance the Company's capital expenditure program. FEFN maintains the same share of long-term debt financing of rate base as FEI, which in the 2019 FEI Annual Review Application was 58.83%. Using this allocation percentage FEFN's share of long-term debt is $7,038 thousand (Section 11, Schedule 43, Line 30, and Column 5) in 2019 and $7,123 thousand (Section 11, Schedule 44, Line 30, and Column 5) in 2020.

9.2.2 Short-Term Debt

The short-term debt for FEFN represents the difference between its long-term debt allocation from FEI and 61.5% of rate base. Interest rate forecasts reflect FEI's methodology as discussed in the 2019 FEI Annual Review Application and repeated below.

FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FEI under its commercial paper program. CDOR is used because FEI's short-term borrowings under its credit facility are priced off of CDOR and so CDOR is tracked relative to FEI's commercial paper borrowings. CDOR is not forecast by economists either; therefore, FEI must first obtain the 3-Month T-Bill rate forecast then convert it to a CDOR forecast. FEI does this by taking the 3 year historical spread between CDOR and the 3-month T-Bill rate. To then derive the short-term borrowing rate forecast, FEI further adjusts the CDOR forecast with the 3-year historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill rate is projected to increase from 1.36 percent in 2018 to approximately 2.26 percent in 2020. The short-term borrowing rate forecast is shown in Table 9-1 below.

Table 9-1: Short Term Interest Rate Forecasts

FEI Short Term Interest Rate	2018	2019	2020
3-Month T-Bill Rate[1]	1.36%	2.05%	2.26%
Spread to CDOR	0.42%	0.42%	0.42%
CDOR Rate	1.78%	2.47%	2.68%
Spread to CP	-0.17%	-0.17%	-0.17%
CP Dealer Commission	0.10%	0.10%	0.10%
Standby Fee on Undrawn Credit[2]	0.40%	0.54%	0.41%
Upfront Fee on Undrawn Credit	0.11%	0.15%	0.11%
FEI Short Term Rate (Rounded)	**2.20%**	**3.10%**	**3.15%**

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 - A standby fee of 16 bps is charged on undrawn credit facility amounts, and has been reflected into the short term rate as if the forecast amount payable had been converted to a rate applied to commercial paper borrowings.

Due to the uncontrollable nature and forecasting uncertainty associated with interest rates, FEFN has an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the amount of debt as compared to forecast.

9.3 SUMMARY OF FINANCING AND RETURN ON EQUITY

The equity financing and ROE for FEFN have been forecast for 2019 and 2020 using FEI's approved percentages. FEFN's debt financing costs on rate base are primarily determined by embedded rates on long-term debt and short-term debt; the short-term rate is forecast to increase starting in 2019.

10. CPCN FOR PROPHET RIVER FIRST NATION (PRFN) EXTENSION

10.1 *INTRODUCTION*

Pursuant to Section 45 and 46 of the UCA, FEI is requesting a CPCN for an extension of FEI's distribution system in FEFN resulting from FEI acquiring 3.2 km of 60 mm polyethylene gas distribution main from the PRFN (the Prophet River Extension). The Prophet River Extension was initiated after PRFN approached and requested that FEI assume ownership and operation of the gas distribution system currently owned by PRFN. The distribution main currently has 53 residential and six commercial properties attached. The acquisition cost is ten dollars plus approximately $8 thousand in legal fees to complete the acquisition. If the CPCN for the Prophet River Extension is approved, FEI will proceed to install individual gas meters to the 53 residential and six commercial properties. As part of the work, FEI will conduct leak suvey and inspection per the standard procedure for pipeline previously not owned by FEI and relocate risers if necessary to fit with the new meters. The estimated capital expenditure for the work is $104 thousand.

FEI expects there will be little to no impact to existing FEFN customers due to the Prophet River Extension and the subsequent capital expenditure. The rate impacts are 0.24 percent in 2019 from the approved 2018 RDA Rates which will then be offset by a decrease of 0.25 percent in 2020. For an average residential customer in FEFN with annual consumption of 125 GJ, the bill impact due to the Prophet River Extension will be an increase of $1.40 in 2019 and a decrease of $1.44 in 2020, or a net decrease of $0.05 over two years. FEI notes the rate impacts account for the additional delivery margin from the additional basic charges to be collected from the 53 residential and six commercial customers after individual meters are installed and they become individual customers of FEFN.

FEI is expecting to complete the Asset Purchase Agreement with PRFN in the fall of 2018 and the work to install individual gas meters at each property will commence and be completed in 2019. Although the Asset Purchase Agreement has not been completed, PRFN is not expecting remuneration for the distribution asset but for the purpose of having a binding contract as part of a legal transaction, an exchange of value between the contracting parties is necessary and therefore, the purchase price is set at ten dollar as a nominal value. FEI therefore does not expect the purchase price to change. FEFN will file the signed Asset Purchase Agreement when it becomes available. The Asset Purchase Agreement will be subject to FEI receiving a CPCN for the Prophet River Extension on terms acceptable to FEI.

10.2 *REGULATORY PROCESS*

Considering the low cost of acquiring the gas distribution system from PRFN and the straight-forward nature of the transaction, FEFN is including its request for a CPCN as part of this Application. Including the request as part of this Application is efficient and cost effective for FEFN customers.

10.3 BACKGROUND

PRFN is located approximately 100 km south of Fort Nelson. PRFN is part of FEI's Fort Nelson Service Area in accordance with FEI's General Terms and Conditions (GT&Cs), approved per Commission Order G-21-14 effective January 1, 2015[27]. Currently, PRFN is a single Rate Schedule 3 (Rate 2.2 prior to the RDA Decision) customer in FEFN with an annual consumption of approximately 7,800 GJ[28].

In September 1986, Tera Environmental Consultants approached BC Gas (predecessor of FEI) requesting a cost estimate for the construction and installation of a natural gas distribution system to service homes on PRFN. Construction of the system was completed by BC Gas in 1989 with PRFN owning and operating the system. The distribution system of the 60 mm polyethylene pipeline is approximately 3.2 km long with 53 residential and six commercial properties attached. BC Gas (now FEI) provides gas service to PRFN through a single gas meter connected to the Spectra transmission main. The single gas meter and the regulator station owned by FEI is less than 200 m away from the PRFN. PRFN is billed by FEFN under Rate Schedule 3 as a single large commercial customer.

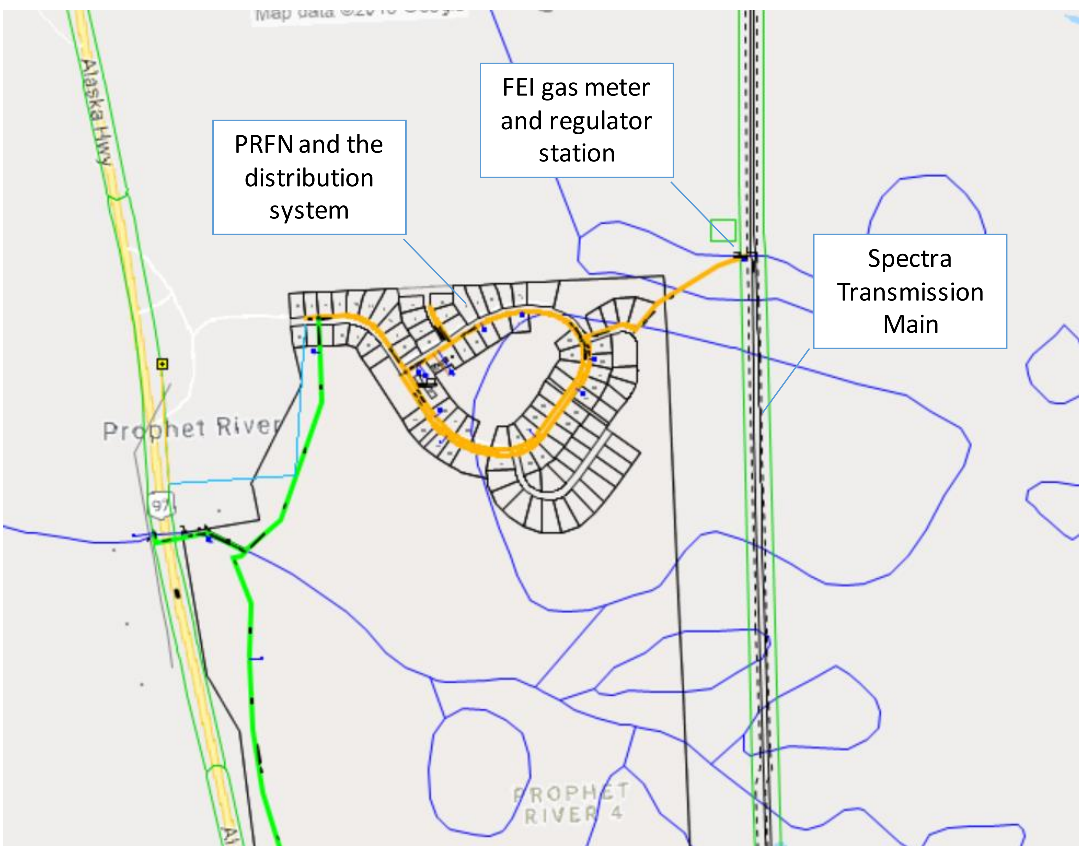
PRFN itself is not a public utility under the UCA. Currently, there are no individual meters installed on properties being served by PRFN's distribution system, and PRFN does not request payment from its members for the use of the system.

Figure 10-1 below shows the location of PRFN relative to Fort Nelson, and Figure 10-2 shows the location of the boundary of PRFN, FEFN's gas meter and regulator station serving PRFN, and the distribution system (in yellow) currently owned by PRFN. FEI notes that there is a distribution main approximately 2.2 km long, owned by FEI, connected downstream of PRFN's private distribution system serving other FEFN customers off the reserve. This distribution main owned by FEI is highlighted in green in Figure 10-2.

[27] FEI's GT&Cs, Service Areas, Section 1, page D-10
[28] Average of 2013 to 2017

Figure 10-1: Prophet River First Nation (PRFN) and Fort Nelson

Figure 10-2: PRFN Distribution System and FEFN's Gas Meter Location



10.4 *CPCN DESCRIPTION*

In February 2016, PRFN first approached FEI requesting that FEI assume ownership and operation of the gas distribution system within PRFN. PRFN expressed to FEI that PRFN has no ability or resources to expand it for the anticipated growth of PRFN over the next 5 to 10 years. PRFN wants to ensure the distribution system, including potential expansion in the future, continues to provide reliable natural gas service to its members and sees FEI as a provincially regulated utility that will be able to operate, maintain, and expand the system safely and reliably.

As indicated above, PRFN does not currently charge its members for use of the system. PRFN has indicated that having individual meters installed to the residential and commercial properties that use the system will be beneficial to its members. PRFN expressed that they would like to see PRFN members begin taking responsibility for their energy costs and that this is an an opportunity for its members to begin establishing a credit rating by paying their own utility bills. The PRFN has agreed to backstop payment should its members fail to make payment to FEI. PRFN also provided a letter to BCUC, included in this Application as Appendix C, confirming that they have requested FEI and in full support of FEI to assume ownership of the distribution system.

If the CPCN for the Prophet River Extension is approved, FEI will proceed to install individual gas meters to the 53 residential and six commercial properties current attached to the system. FEI estimates the cost for the work at $104 thousand[29], including relocating risers if necessary to install the meters, a leak survey and inspection as part of standard procedure for the newly acquired pipeline.

10.5 *PERMITTING*

The Asset Purchase Agreement will be conditional upon FEI obtaining a right of way permit pursuant to Section 28(2) of the *Indian Act*. The permit will grant FEI the necessary land tenure rights to own, operate and maintain the gas distribution system on the PRFN reserve. FEI will be engaging with the Ministry of Indian Affairs and Northern Development (representing Her Majesty The Queen in Right of Canada) and the PRFN to negotiate acceptable permit terms.

10.6 *JUSTIFICATION*

10.6.1 Alternatives

The purchase of the PRFN gas distribution system is a single-option transaction. Therefore, a comparison of different alternatives, along with a related discussion of the costs, benefits, and financial analysis has not been included.

[29] The cost estimate for installation gas meters and relocating riser locations (if necessary) is based on current unit pricing for FEFN attaching new customers

10.6.2 Incremental Revenue Requirement Impacts to FEFN

FEI expects there will be little to no impact to existing FEFN customers due to the Prophet River Extension.

Based on an addition of ten dollars to FEFN's rate base in 2019 for purchasing the existing gas distribution system from PRFN, plus approximately $8 thousand in legal fees and the subsequent capital expenditure of approximately $104 thousand, and considering the incremental revenue from basic charges, the rate impacts are an increase of 0.24 percent in 2019 which will then be offset by a decrease of 0.25 percent in 2020 when compared to the approved 2018 RDA Rates.

Table 10-1 below summarizes the incremental cost of service in 2019 and 2020 when compared to the approved 2018 revenue requirements, the offsetting delivery revenues from PRFN as a result of the additional basic charges to be collected from the individual customers instead of just one large commercial customer, and the rate impact to FEFN in 2019 and 2020. For an average residential customer in FEFN with annual consumption of 125 GJ, the bill impact due to the project will be an increase of $1.40 in 2019 and a decrease of $1.44 in 2020, or a net decrease of $0.05 over two years.

Table 10-1: Summary of Financial Analysis and Rate Impact of PRFN Project[30,31]

	2019	2020
Incremental Annual Revenue Requirement ($)	9,674	14,279
Offseting Additional Revenue from PRFN ($)	(3,622)	(14,487)
Net Incrmental Annual Revenue Requirement ($)	6,052	(208)
2018 Approved Revenue Requirement (G-196-17), ($000s)	2,489	2,489
Rate Impact (%) to Approved 2018 Rates	0.24%	(0.01%)
Rate Impact (%), Year-to-Year	0.24%	(0.25%)

The rate impacts indicated above do not account for the potential growth in PRFN as discussed in Section 10.6.3 below. Based on the preliminary expansion plans from PRFN, FEI believes that the acquisition provides the potential for additional revenue to FEFN which will have a positive impact on rates.

10.6.3 Benefits to PRFN

The primary reason that PRFN is requesting that FEI assume ownership and operation of its existing gas distribution system is because PRFN expressed they have no ability or resources

30 The offsetting revenue in 2019 due to additional Basic Charge from PRFN assumed only 3 months as the work is estimated to complete in summer/fall of 2019. 2020 assumes 12 months of additional revenue from PRFN.

31 The annual revenue requirement includes additional O&M costs to serve the additional 59 residential and commercial customers. FEI estimates the additional O&M cost will be minimal as FEFN is already servicing the distribution main, services and meter sets that are owned by FEFN and located downstream of PRFN (refer to Figure 10-2). Maintenance work as well as meter reads at PRFN are expected to be completed at the same time as FEFN maintains and services the existing distribution system downstream of PRFN.

to maintain the existing distribution system while expanding it for their planned growth. PRFN wants to ensure safe and reliable natural gas service is continued to be provided to its members and expand the system in accordance to safety standard.

PRFN indicated to FEI that they plan to expand their community in the near future, including new restaurants, hotels/motels, convenience stores and other retail spaces, a church, a Fire Hall and subdivision housings for PRFN members. PRFN expressed they would have no ability or resources to expand the existing gas distribution system to accommodate the anticipated growth in PRFN. Based on these preliminary expansion plans from PRFN, FEI believes that the acquisition provides the potential for additional revenue to FEFN and which would have a positive impact on rates. This will also benefit existing customers in FEFN which will also see the positive impact on rates due to the potential growth.

FEI is able to address PRFN's needs as a proven and experienced operator of a natural gas distribution system with the financial ability to maintain, upgrade and expand assets. PRFN also sees FEI, as a provincially regulated utility and already providing natural gas service to PRFN, as being best situated to operate and maintain the existing system safely and reliably, and also capable of expanding the system to accommodate PRFN's potential growth in the near future.

Additionally, PRFN believes that having individual members paying their own utility bills would allow the individual members to establish credit ratings, which is seen as a driver of economic opportunity.

10.6.4 No Detrimental Effect to Existing Users of PRFN Gas Distribution System

PRFN and its members will continue to receive natural gas service from FEI via FEFN regardless of the purchase of the assets. FEI's service to PRFN will not change as a result of the transaction.

As discussed in the previous section, although the Project will result in PRFN's members being responsible for their own natural gas bill as a result of this transaction, PRFN also agreed to backstop payment should its members fail to make payment to FEFN.

10.6.5 Risk Associated with the Prophet River Extension

FEI considers the following risks associated with the Prophet River Extension:

- The acquisition is dependent on FEFN successfully obtaining the right of way pursuant to Section 28(2) of the *Indian Act* as discussed in Section 8.8.3.2. FEFN is already engaged in negotiations with Ministry of Indian Affairs and Northern Development (representing Her Majesty The Queen in Right of Canada). PRFN will also be involved in permit negotiations; and
- The actual condition of the existing distribution system currently owned by PRFN. FEI considers the risk of this is small based on the history of the pipeline and FEI's

observations of the system which is in generally good condition. Furthermore, the pipeline is made of polyethylene which does not have the concern of cathodic protection like steel pipe. The distribution system was installed by BC Gas (predecessor of FEI) in 1989 following BC Gas' safety standards at that time. Over the years, FEI has been providing service from FEFN to PRFN regularly for any new installation to the existing distribution system as well as responding emergency calls and repairs such as leak detection from PRFN. Therefore, the risk of a long term leak that has been undetected over the years is small. FEI is also aware of the work within PRFN that might have an impact to the pipeline and is generally comfortable with the condition of the system. As standard practice, FEFN is planning to conduct a leak survey and inspection once the system is acquired by FEI. Given the distribution main currently owned by PRFN is 29 years old and distribution mains (currently owned by FEI) typically have an estimated life of approximately 65 years, FEI considers the risk related to pipe condition is acceptable.

10.6.6 Provincial Government Energy Objectives and Policy Considerations

The purchase of the PRFN gas distribution system will have a small but positive impact in advancing government energy objectives. PRFN believes that if the use of natural gas is individually metered and its members are responsible for their energy costs, it will result in its members consuming natural gas more conservatively and will also lead to more energy efficiency upgrades such as eliminating air leakage, improving insulation, and replacing inefficient heating furnaces or boilers with high efficiency models. FEI's conservation programs will also be offered to the members of PRFN once they become individual customers of FEFN.

10.6.7 Conclusion

FEI respectfully submits that its proposed extension of FEFN's distribution system to include the PRFN gas distribution system is in the public interest and should be granted a CPCN. The transaction will address the request from PRFN, provide benefits to PRFN and its members, will have little to no impact to existing FEFN customers in the Test Period, and the potential for future positive rate impacts as PRFN expands its community. The assets are a natural fit into FEFN's existing assets, which are of similar type, and within FEFN's existing service area. The transaction, once approved by the Commission, will also be subject to FEI obtaining a right of way pursuant to Section 28(2) of the *Indian Act*.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base - 2019	2
Utility Rate Base - 2020	3
Capital Expenditures To Plant Reconciliation - 2019	4
Plant In Service Continuity Schedule - 2019	5
Plant In Service Continuity Schedule - 2020	6
Accumulated Depreciation Continuity Schedule - 2019	7
Accumulated Depreciation Continuity Schedule - 2020	8
Contributions In Aid Of Construction Continuity Schedule - 2019	9
Contributions In Aid Of Construction Continuity Schedule - 2020	10
Net Salvage Continuity Schedule - 2019	11
Net Salvage Continuity Schedule - 2020	12
Unamortized Deferred Charges And Amortization - Rate Base - 2019	13
Unamortized Deferred Charges And Amortization - Rate Base - 2020	14
Unamortized Deferred Charges And Amortization - Non-Rate Base - 2019	15
Unamortized Deferred Charges And Amortization - Non-Rate Base - 2020	16
Working Capital Allowance - 2019	17
Working Capital Allowance - 2020	18
Cash Working Capital - 2019	19
Cash Working Capital - 2020	20
Revenue Requirement	
Utility Income And Earned Return - 2019	21
Utility Income And Earned Return - 2020	22
Volume And Revenue - 2019	23
Volume And Revenue - 2020	24
Cost Of Energy - 2019	25
Cost Of Energy - 2020	26
Margin And Revenue At Existing And Revised Rates - 2019	27
Margin And Revenue At Existing And Revised Rates - 2020	28
Operating And Maintenance Expense - Resource View - 2019 & 2020	29
Operating And Maintenance Expense - Activity View - 2019 & 2020	30
Depreciation And Amortization Expense - 2019	31
Depreciation And Amortization Expense - 2020	32
Property And Sundry Taxes - 2019	33
Property And Sundry Taxes - 2020	34
Other Revenue - 2019	35
Other Revenue - 2020	36
Income Taxes - 2019	37
Income Taxes - 2020	38
Capital Cost Allowance - 2019	39
Capital Cost Allowance - 2020	40
Return On Capital - 2019	41
Return On Capital - 2020	42
Embedded Cost Of Long Term Debt - 2019	43
Embedded Cost Of Long Term Debt - 2020	44

SUMMARY OF RATE CHANGE
FOR THE YEARS ENDING DECEMBER 31, 2019 and 2020
($millions)

Line No.	Particulars	2019 Forecast		2020 Forecast		Cumulative		Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**VOLUME/REVENUE RELATED**							
2	Customer Growth and Volume	$ 0.176		$ 0.085		$ 0.261		
3	Change in Other Revenue	0.008	0.184	0.001	0.086	0.009	0.270	
4								
5	**O&M CHANGES**							
6	Gross O&M Change	(0.024)		0.002		(0.022)		
7	Capitalized Overhead Change	0.003	(0.021)	(0.001)	0.001	0.002	(0.020)	
8								
9	**DEPRECIATION EXPENSE**							
10	Plant Depreciation		0.041		0.005		0.046	
11								
12	**AMORTIZATION EXPENSE**							
13	CIAC	(0.001)		0.001		0.000		
14	Deferrals	(0.013)	(0.014)	0.043	0.044	0.03	0.030	
15								
16	**FINANCING AND RETURN ON EQUITY**							
17	Financing Rate Changes	(0.012)		(0.001)		(0.013)		
18	Financing Ratio Changes	0.013		0.000		0.013		
19	Rate Base Growth	0.047	0.048	0.011	0.010	0.058	0.058	
20								
21	**TAX EXPENSE**							
22	Property and Other Taxes	(0.018)		0.007		(0.011)		
23	Other Income Taxes Changes	0.027	0.009	0.027	0.034	0.054	0.043	
24								
25	**DEFERRED 2017/2018 REVENUE DEFICIENCY**		(0.146)		0.000		(0.146)	
26								
27	Revenue Deficiency (Surplus)		$ 0.101		$ 0.180		$ 0.281	Schedule 21 & 22, Line 11, Column 4
28								
29	Non-Bypass Margin @ Existing Rates*		2.313		(0.085)		2.228	Schedule 21 & 22, Line 15, Column 3
30	Rate Change		4.37%				12.61%	
31								
32	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 Rate Design Application (RDA) on July 20, 2018.							

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	$ 15,918	$ 16,517	$ 599	Schedule 5, Line 38, Column 3
2	Net Additions	463	670	207	Schedule 5, Line 38, Column 4+5+6
3	Plant in Service, Ending	16,381	17,187	806	
4					
5	Accumulated Depreciation Beginning	$ (4,421)	$ (4,507)	$ (86)	Schedule 7, Line 38, Column 5
6	Net Additions	(256)	(357)	(101)	Schedule 7, Line 38, Column 6+7
7	Accumulated Depreciation Ending	(4,677)	(4,864)	(187)	
8					
9	CIAC, Beginning	$ (1,326)	$ (1,331)	$ (5)	Schedule 9, Line 4, Column 2
10	Net Additions	-	-	-	Schedule 9, Line 4, Column 5+6
11	CIAC, Ending	(1,326)	(1,331)	(5)	
12					
13	Accumulated Amortization Beginning - CIAC	$ 730	$ 760	$ 30	Schedule 9, Line 9, Column 2
14	Net Additions	28	29	1	Schedule 9, Line 9, Column 5+6
15	Accumulated Amortization Ending - CIAC	758	789	31	
16					
17	Net Plant in Service, Mid-Year	$ 11,019	$ 11,610	$ 591	
18					
19	Capital Work in Progress, No AFUDC	$ 35	$ 121	$ 86	
20	Unamortized Deferred Charges	126	130	4	Schedule 13, Line 22, Column 10
21	Working Capital	48	71	23	Schedule 17, Line 11, Column 3
22					
23	Mid-Year Utility Rate Base	$ 11,228	$ 11,932	$ 704	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 16,517	$ 17,187	$ 670	Schedule 6, Line 38, Column 3
2	Net Additions	670	396	(274)	Schedule 6, Line 38, Column 4+5+6
3	Plant in Service, Ending	17,187	17,583	396	
4					
5	Accumulated Depreciation Beginning	$ (4,507)	$ (4,864)	$ (357)	Schedule 8, Line 38, Column 5
6	Net Additions	(357)	(199)	158	Schedule 8, Line 38, Column 6+7
7	Accumulated Depreciation Ending	(4,864)	(5,063)	(199)	
8					
9	CIAC, Beginning	$ (1,331)	$ (1,331)	$ -	Schedule 10, Line 4, Column 2
10	Net Additions	-	-	-	Schedule 10, Line 4, Column 5+6
11	CIAC, Ending	(1,331)	(1,331)	-	
12					
13	Accumulated Amortization Beginning - CIAC	$ 760	$ 789	$ 29	Schedule 10, Line 9, Column 2
14	Net Additions	29	28	(1)	Schedule 10, Line 9, Column 5+6
15	Accumulated Amortization Ending - CIAC	789	817	28	
16					
17	Net Plant in Service, Mid-Year	$ 11,610	$ 11,894	$ 284	
18					
19	Capital Work in Progress, No AFUDC	$ 121	$ 121	$ -	
20	Unamortized Deferred Charges	130	21	(109)	Schedule 14, Line 22, Column 10
21	Working Capital	71	72	1	Schedule 18, Line 11, Column 3
22					
23	Mid-Year Utility Rate Base	$ 11,932	$ 12,108	$ 176	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEARS ENDING DECEMBER 31, 2019 and 2020
($000s)

Schedule 4

Line No.	Particulars	2019 Forecast	2020 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPEX**			
2				
3	Total Regular Capital Expenditures	$ 649	$ 537	
4				
5	Total Special Projects and CPCNs	$ -	$ -	
6				
7	**Total Capital Expenditures**	$ 649	$ 537	
8				
9				
10	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
11				
12	Regular Capital Expenditures	$ 649	$ 537	
13	Add - Capitalized Overheads	121	122	Schedule 29, Line 22, Column 5 & 6
14	Add - AFUDC	-	-	
15	Gross Capital Expenditures	770	659	
16	Change in Work in Progress	-	-	
17	**Total Additions to Plant - Regular Capital**	$ 770	$ 659	
18				
19	Special Projects and CPCNs	$ -	$ -	
20	**Total Additions to Plant - CPCNs**	$ -	$ -	
21				
22	**Grand Total Additions to Plant**	$ 770	$ 659	

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

Line No.	Account	Particulars	12/31/2018	CPCN's	Additions	Retirements	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**INTANGIBLE PLANT**						
2	461-01	Transmission Land Rights	$ 78	$ -	$ -	$ -	$ 78	
3	471-01	Distribution Land Rights	20	-	-	-	20	
4	402-01	Application Software - 12.5%	401	-	14	(32)	383	
5	402-02	Application Software - 20%	51	-	14	(2)	63	
6			$ 550	$ -	$ 28	$ (34)	$ 544	
7								
8		**TRANSMISSION PLANT**						
9	463-00	Measuring Structures	$ 10	$ -	$ -	$ -	$ 10	
10	465-00	Mains	5,733	-	-	-	5,733	
11	467-10	Measuring & Regulating Equipment	670	-	-	-	670	
12	467-20	Telemetering	27	-	6	-	33	
13			$ 6,440	$ -	$ 6	$ -	$ 6,446	
14								
15		**DISTRIBUTION PLANT**						
16	472-00	Structures & Improvements	$ 273	$ -	$ -	$ -	$ 273	
17	473-00	Services	2,531	-	86	(6)	2,611	
18	474-00	House Regulators & Meter Installations	492	-	-	(36)	456	
19	474-02	Meters/Regulators Installations	152	-	30	-	182	
20	475-00	Mains	3,170	-	349	-	3,519	
21	477-10	Measuring & Regulating Equipment	1,721	-	198	-	1,919	
22	477-20	Telemetering	240	-	-	-	240	
23	478-10	Meters	12	-	32	-	44	
24			$ 8,591	$ -	$ 695	$ (42)	$ 9,244	
25								
26		**GENERAL PLANT & EQUIPMENT**						
27	480-00	Land in Fee Simple	$ 1	$ -	$ -	$ -	$ 1	
28	482-10	Frame Buildings	673	-	20	-	693	
29	483-30	GP Office Equipment	26	-	-	(6)	20	
30	483-40	GP Furniture	1	-	-	-	1	
31	483-10	GP Computer Hardware	147	-	11	-	158	
32	483-20	GP Computer Software	22	-	-	(7)	15	
33	484-00	Vehicles	29	-	-	-	29	
34	486-00	Small Tools & Equipment	32	-	10	(6)	36	
35	488-10	Telephone	5	-	-	(5)	-	
36			$ 936	$ -	$ 41	$ (24)	$ 953	
37								
38		**Total Plant in Service**	$ 16,517	$ -	$ 770	$ (100)	$ 17,187	
39								
40		Cross Reference		Schedule 4, Line 20, Column 2	Schedule 4, Line 17, Column 2			

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	12/31/2019	CPCN's	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**INTANGIBLE PLANT**						
2	461-01	Transmission Land Rights	$ 78	$ -	$ -	$ -	$ 78	
3	471-01	Distribution Land Rights	20	-	-	-	20	
4	402-01	Application Software - 12.5%	383	-	14	(250)	147	
5	402-02	Application Software - 20%	63	-	14	-	77	
6			$ 544	$ -	$ 28	$ (250)	$ 322	
7								
8		**TRANSMISSION PLANT**						
9	463-00	Measuring Structures	$ 10	$ -	$ -	$ -	$ 10	
10	465-00	Mains	5,733	-	-	-	5,733	
11	467-10	Measuring & Regulating Equipment	670	-	-	-	670	
12	467-20	Telemetering	33	-	7	-	40	
13			$ 6,446	$ -	$ 7	$ -	$ 6,453	
14								
15		**DISTRIBUTION PLANT**						
16	472-00	Structures & Improvements	$ 273	$ -	$ -	$ -	$ 273	
17	473-00	Services	2,611	-	107	(7)	2,711	
18	474-00	House Regulators & Meter Installations	456	-	-	(1)	455	
19	474-02	Meters/Regulators Installations	182	-	18	-	200	
20	475-00	Mains	3,519	-	364	-	3,883	
21	477-10	Measuring & Regulating Equipment	1,919	-	94	-	2,013	
22	477-20	Telemetering	240	-	-	-	240	
23	478-10	Meters	44	-	-	-	44	
24			$ 9,244	$ -	$ 583	$ (8)	$ 9,819	
25								
26		**GENERAL PLANT & EQUIPMENT**						
27	480-00	Land in Fee Simple	$ 1	$ -	$ -	$ -	$ 1	
28	482-10	Frame Buildings	693	-	20	-	713	
29	483-30	GP Office Equipment	20	-	-	-	20	
30	483-40	GP Furniture	1	-	-	-	1	
31	483-10	GP Computer Hardware	158	-	11	-	169	
32	483-20	GP Computer Software	15	-	-	(5)	10	
33	484-00	Vehicles	29	-	-	-	29	
34	486-00	Small Tools & Equipment	36	-	10	-	46	
35	488-10	Telephone	-	-	-	-	-	
36			$ 953	$ -	$ 41	$ (5)	$ 989	
37								
38		**Total Plant in Service**	$ 17,187	$ -	$ 659	$ (263)	$ 17,583	
39								
40		Cross Reference		Schedule 4, Line 20, Column 3	Schedule 4, Line 17, Column 3			

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

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2018	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**INTANGIBLE PLANT**									
2	461-01	Transmission Land Rights	$ 78	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
3	471-01	Distribution Land Rights	20	0.00%	-	-	-	-	-	-	
4	402-01	Application Software - 12.5%	401	12.50%	285	50	(32)	-	-	303	
5	402-02	Application Software - 20%	51	20.00%	9	8	(2)	-	-	15	
6			$ 550		$ 294	$ 58	$ (34)	$ -	$ -	$ 318	
7											
8		**TRANSMISSION PLANT**									
9	463-00	Measuring Structures	$ 10	2.29%	$ 2	$ -	$ -	$ -	$ -	$ 2	
10	465-00	Mains	5,733	1.47%	593	84	-	-	-	677	
11	467-10	Measuring & Regulating Equipment	670	2.41%	295	16	-	-	-	311	
12	467-20	Telemetering	27	9.75%	7	3	-	-	-	10	
13			$ 6,440		$ 897	$ 103	$ -	$ -	$ -	$ 1,000	
14											
15		**DISTRIBUTION PLANT**									
16	472-00	Structures & Improvements	$ 273	2.41%	$ 126	$ 7	$ -	$ -	$ -	$ 133	
17	473-00	Services	2,531	2.45%	993	62	(6)	-	-	1,049	
18	474-00	House Regulators & Meter Installations	492	5.99%	405	29	(36)	-	-	398	
19	474-02	Meters/Regulators Installations	152	4.55%	25	7	-	-	-	32	
20	475-00	Mains	3,170	1.54%	705	49	-	-	-	754	
21	477-10	Measuring & Regulating Equipment	1,721	3.05%	697	53	-	-	-	750	
22	477-20	Telemetering	240	2.82%	21	7	-	-	-	28	
23	478-10	Meters	12	7.09%	16	1	-	-	-	17	
24			$ 8,591		$ 2,988	$ 215	$ (42)	$ -	$ -	$ 3,161	
25											
26		**GENERAL PLANT & EQUIPMENT**									
27	480-00	Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
28	482-10	Frame Buildings	673	6.04%	215	41	-	-	-	256	
29	483-30	GP Office Equipment	26	6.67%	5	2	(6)	-	-	1	
30	483-40	GP Furniture	1	5.00%	1	-	-	-	-	1	
31	483-10	GP Computer Hardware	147	20.00%	64	29	-	-	-	93	
32	483-20	GP Computer Software	22	12.50%	17	3	(7)	-	-	13	
33	484-00	Vehicles	29	10.55%	13	3	-	-	-	16	
34	486-00	Small Tools & Equipment	32	5.00%	9	2	(6)	-	-	5	
35	488-10	Telephone	5	6.67%	4	1	(5)	-	-	-	
36			$ 936		$ 328	$ 81	$ (24)	$ -	$ -	$ 385	
37											
38		**Total**	$ 16,517		$ 4,507	$ 457	$ (100)	$ -	$ -	$ 4,864	
39											
40		Cross Reference	Schedule 5, Line 38, Column 3+4								

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2019	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**INTANGIBLE PLANT**									
2	461-01	Transmission Land Rights	$ 78	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
3	471-01	Distribution Land Rights	20	0.00%	-	-	-	-	-	-	
4	402-01	Application Software - 12.5%	383	12.50%	303	48	(250)	-	-	101	
5	402-02	Application Software - 20%	63	20.00%	15	1	-	-	-	16	
6			$ 544		$ 318	$ 49	$ (250)	$ -	$ -	$ 117	
7											
8		**TRANSMISSION PLANT**									
9	463-00	Measuring Structures	$ 10	2.29%	$ 2	$ -	$ -	$ -	$ -	$ 2	
10	465-00	Mains	5,733	1.47%	677	85	-	-	-	762	
11	467-10	Measuring & Regulating Equipment	670	2.41%	311	16	-	-	-	327	
12	467-20	Telemetering	33	9.75%	10	3	-	-	-	13	
13			$ 6,446		$ 1,000	$ 104	$ -	$ -	$ -	$ 1,104	
14											
15		**DISTRIBUTION PLANT**									
16	472-00	Structures & Improvements	$ 273	2.41%	$ 133	$ 7	$ -	$ -	$ -	$ 140	
17	473-00	Services	2,611	2.45%	1,049	63	(7)	-	-	1,105	
18	474-00	House Regulators & Meter Installations	456	5.99%	398	27	(1)	-	-	424	
19	474-02	Meters/Regulators Installations	182	4.55%	32	8	-	-	-	40	
20	475-00	Mains	3,519	1.54%	754	54	-	-	-	808	
21	477-10	Measuring & Regulating Equipment	1,919	3.05%	750	58	-	-	-	808	
22	477-20	Telemetering	240	2.82%	28	7	-	-	-	35	
23	478-10	Meters	44	7.09%	17	3	-	-	-	20	
24			$ 9,244		$ 3,161	$ 227	$ (8)	$ -	$ -	$ 3,380	
25											
26		**GENERAL PLANT & EQUIPMENT**									
27	480-00	Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
28	482-10	Frame Buildings	693	6.04%	256	42	-	-	-	298	
29	483-30	GP Office Equipment	20	6.67%	1	1	-	-	-	2	
30	483-40	GP Furniture	1	5.00%	1	-	-	-	-	1	
31	483-10	GP Computer Hardware	158	20.00%	93	32	-	-	-	125	
32	483-20	GP Computer Software	15	12.50%	13	2	(5)	-	-	10	
33	484-00	Vehicles	29	10.55%	16	3	-	-	-	19	
34	486-00	Small Tools & Equipment	36	5.00%	5	2	-	-	-	7	
35	488-10	Telephone	-	6.67%	-	-	-	-	-	-	
36			$ 953		$ 385	$ 82	$ (5)	$ -	$ -	$ 462	
37											
38		**Total**	$ 17,187		$ 4,864	$ 462	$ (263)	$ -	$ -	$ 5,063	
39											
40		Cross Reference	Schedule 6, Line 38, Column 3+4								

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

Line No.	Particulars	12/31/2018	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 1,166	$ -	$ -	$ -	$ -	$ 1,166	
3	Transmission Contributions	165	-	-	-	-	165	
4	**Total**	$ 1,331	$ -	$ -	$ -	$ -	$ 1,331	
5								
6	**Amortization**							
7	Distribution Contributions	$ (729)	$ -	$ -	$ (27)	$ -	$ (756)	
8	Transmission Contributions	(31)	-	-	(2)	-	(33)	
9	**Total**	$ (760)	$ -	$ -	$ (29)	$ -	$ (789)	
10								
11	**Net CIAC**	$ 571	$ -	$ -	$ (29)	$ -	$ 542	
12								

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/2019	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 1,166	$ -	$ -	$ -	$ -	$ 1,166	
3	Transmission Contributions	165	-	-	-	-	165	
4	**Total**	$ 1,331	$ -	$ -	$ -	$ -	$ 1,331	
5								
6	**Amortization**							
7	Distribution Contributions	$ (756)	$ -	$ -	$ (27)	$ -	$ (783)	
8	Transmission Contributions	(33)	-	-	(1)	-	(34)	
9	**Total**	$ (789)	$ -	$ -	$ (28)	$ -	$ (817)	
10								
11	**Net CIAC**	$ 542	$ -	$ -	$ (28)	$ -	$ 514	
12								

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2018	Net Salvage Provision	Retirement Costs / Proceeds on Disp.	12/31/2019	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	463-00	Measuring Structures	$ 10	0.57%	$ -	$ -	$ -	$ -	
3	465-00	Mains	5,733	0.37%	54	21	-	75	
4	467-10	Measuring & Regulating Equipment	670	0.22%	6	1	-	7	
5			$ 6,413		$ 60	$ 22	$ -	$ 82	
6									
7		**DISTRIBUTION PLANT**							
8	472-00	Structures & Improvements	$ 273	0.32%	$ 3	$ 1	$ -	$ 4	
9	473-00	Services	2,531	1.61%	74	42	-	116	
10	474-00	House Regulators & Meter Installations	492	1.77%	24	9	(11)	22	
11	474-02	Meters/Regulators Installations	152	0.00%	1	-	-	1	
12	475-00	Mains	3,170	0.43%	(35)	15	-	(20)	
13	477-10	Measuring & Regulating Equipment	1,721	0.46%	34	8	-	42	
14	477-20	Telemetering	240	0.42%	2	2	-	4	
15	478-10	Meters	12	-0.26%	-	-	-	-	
16			$ 8,591		$ 103	$ 77	$ (11)	$ 169	
17									
18		**GENERAL PLANT & EQUIPMENT**							
19	482-20	Masonry Buildings	$ -	0.25%	$ (4)	$ -	$ -	$ (4)	
20	484-00	Vehicles	-	-1.00%	-	-	-	-	
21									
22									
23		**Total**	$ 15,004		$ 159	$ 99	$ (11)	$ 247	
24									
25		Cross Reference	Schedule 5, Column 3+4						

NET SALVAGE CONTINUITY SCHEDULE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2019	Net Salvage Provision	Retirement Costs / Proceeds on Disp.	12/31/2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	463-00	Measuring Structures	$ 10	0.57%	$ -	$ -	$ -	$ -	
3	465-00	Mains	5,733	0.37%	75	21	-	96	
4	467-10	Measuring & Regulating Equipment	670	0.22%	7	3	-	10	
5			$ 6,413		$ 82	$ 24	$ -	$ 106	
6									
7		**DISTRIBUTION PLANT**							
8	472-00	Structures & Improvements	$ 273	0.32%	$ 4	$ -	$ -	$ 4	
9	473-00	Services	2,611	1.61%	116	42	-	158	
10	474-00	House Regulators & Meter Installations	456	1.77%	22	8	(11)	19	
11	474-02	Meters/Regulators Installations	182	0.00%	1	-	-	1	
12	475-00	Mains	3,519	0.43%	(20)	15	-	(5)	
13	477-10	Measuring & Regulating Equipment	1,919	0.46%	42	9	-	51	
14	477-20	Telemetering	240	0.42%	4	1	-	5	
15	478-10	Meters	44	-0.26%	-	-	-	-	
16			$ 9,244		$ 169	$ 75	$ (11)	$ 233	
17									
18		**GENERAL PLANT & EQUIPMENT**							
19	482-20	Masonry Buildings	$ -	0.25%	$ (4)	$ -	$ -	$ (4)	
20	484-00	Vehicles	-	-1.00%	-	-	-	-	
21									
22									
23		**Total**	$ 15,657		$ 247	$ 99	$ (11)	$ 335	
24									
25		Cross Reference	Schedule 6, Column 3+4						

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

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Forecasting Variance Accounts										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	$ 142	$ -	$ -	$ -	$ -	$ (97)	$ 26	$ 71	$ 107	
3	Interest on RSAM	5	-	-	-	-	(4)	1	2	4	
4	Gas Cost Reconciliation Account	(43)	-	59	(16)	-	-	-	-	(22)	
5	Property Tax Variance	(49)	-	-	-	17	-	-	(32)	(41)	
6	Interest Variance	1	-	-	-	(1)	-	-	-	1	
7	Customer Service Variance Account	(3)	-	-	-	3	-	-	-	(2)	
8		$ 53	$ -	$ 59	$ (16)	$ 19	$ (101)	$ 27	$ 41	$ 47	
9											
10	Benefits Matching Accounts										
11	Energy Efficiency & Conservation (EEC)	$ 109	$ -	$ 86	$ (23)	$ (12)	$ -	$ -	$ 160	$ 135	
12	2019-2020 Revenue Requirement Application	44	-	10	(3)	(22)	-	-	29	37	
13	2017-2018 Revenue Requirement Application	(27)	-	-	-	27	-	-	-	(14)	
14	2017 Rate Design Application	20	-	-	-	(4)	-	-	16	18	
15	2016 Cost of Capital Application	1	-	-	-	(1)	-	-	-	1	
16	Gains and Losses on Asset Disposition	68	-	-	-	(11)	-	-	57	63	
17	Net Salvage Provision/Cost	(159)	-	11	-	(99)	-	-	(247)	(203)	
18	Billing system costs for FEFN Rate changes	51	-	-	-	(10)	-	-	41	46	
19		$ 107	$ -	$ 107	$ (26)	$ (132)	$ -	$ -	$ 56	$ 83	
20											
21											
22	**Total Deferred Charges for Rate Base**	$ 160	$ -	$ 166	$ (42)	$ (113)	$ (101)	$ 27	$ 97	$ 130	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2020	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Forecasting Variance Accounts										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	$ 71	$ -	$ -	$ -	$ -	$ (97)	$ 26	$ -	$ 36	
3	Interest on RSAM	2	-	-	-	-	(3)	1	-	1	
4	Gas Cost Reconciliation Account	-	-	-	-	-	-	-	-	-	
5	Property Tax Variance	(32)	-	-	-	16	-	-	(16)	(24)	
6	Interest Variance	-	-	-	-	-	-	-	-	-	
7	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	
8		$ 41	$ -	$ -	$ -	$ 16	$ (100)	$ 27	$ (16)	$ 13	
9											
10	Benefits Matching Accounts										
11	Energy Efficiency & Conservation (EEC)	$ 160	$ -	$ 86	$ (23)	$ (19)	$ -	$ -	$ 204	$ 182	
12	2019-2020 Revenue Requirement Application	29	-	-	-	(29)	-	-	-	15	
13	2017-2018 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	
14	2017 Rate Design Application	16	-	-	-	(4)	-	-	12	14	
15	2016 Cost of Capital Application	-	-	-	-	-	-	-	-	-	
16	Gains and Losses on Asset Disposition	57	-	-	-	(11)	-	-	46	52	
17	Net Salvage Provision/Cost	(247)	-	11	-	(99)	-	-	(335)	(291)	
18	Billing system costs for FEFN Rate changes	41	-	-	-	(10)	-	-	31	36	
19		$ 56	$ -	$ 97	$ (23)	$ (172)	$ -	$ -	$ (42)	$ 8	
20											
21											
22	**Total Deferred Charges for Rate Base**	$ 97	$ -	$ 97	$ (23)	$ (156)	$ (100)	$ 27	$ (58)	$ 21	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 15
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Other Accounts										
2	FN Right-of-Way Agreement	131	-	7	-	-	-	-	138	135	
3											
4											
5	**Total Deferred Charges for Non Rate Base**	$ 131	$ -	$ 7	$ -	$ -	$ -	$ -	$ 138	$ 135	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 16
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2020	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Other Accounts										
2	FN Right-of-Way Agreement	138	-	8	-	-	-	-	146	142	
3											
4											
5	**Total Deferred Charges for Non Rate Base**	$ 138	$ -	$ 8	$ -	$ -	$ -	$ -	$ 146	$ 142	

WORKING CAPITAL ALLOWANCE
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	**Cash Working Capital**				
2	Cash Working Capital	$ 71	$ 73	$ 2	Schedule 19, Line 26, Column 5
3					
4	Less: Funds Available				
5	Reserve for bad debts	(12)	(16)	(4)	
6	Employee Withholdings	(25)	(13)	12	
7					
8	**Other Working Capital Items**				
9	Inventory - Materials and Supplied	14	27	13	
10					
11	Total	$ 48	$ 71	$ 23	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 73	$ 74	$ 1	Schedule 20, Line 26, Column 5
3					
4	Less: Funds Available				
5	Reserve for bad debts	(16)	(16)	-	
6	Employee Withholdings	(13)	(13)	-	
7					
8	**Other Working Capital Items**				
9	Inventory - Materials and Supplied	27	27	-	
10					
11	Total	$ 71	$ 72	$ 1	

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

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 & Commercial Tariff Revenue	$ 2,983	38.5	$ 114,748		
4	Industrial Tariff Revenue	163	45.2	7,368		
5						
6	**Other Revenue**					
7	Late Payment Charges	13	38.3	498		
8	Connection Charges	5	38.3	192		
9						
10	Total	$ 3,164		$ 122,806	38.8	
11						
12	**EXPENSES**					
13	Energy Purchases	$ 732	(40.2)	$ (29,426)		
14	Operating and Maintenance	892	(25.5)	(22,746)		
15	Property Taxes	121	(2.0)	(242)		
16	Carbon Tax	924	(29.1)	(26,888)		
17	GST	27	(38.8)	(1,048)		
18	PST	17	(37.1)	(631)		
19	Income Tax	102	(15.2)	(1,550)		
20						
21	Total	$ 2,815		$ (82,531)	(29.3)	
22						
23	Net Lag (Lead) Days				9.5	
24	Total Expenses				$ 2,815	
25						
26	Cash Working Capital				$ 73	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2020 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 & Commercial Tariff Revenue	$ 3,025	38.5	$ 116,385		
4	Industrial Tariff Revenue	176	45.2	7,955		
5						
6	**Other Revenue**					
7	Late Payment Charges	12	38.3	460		
8	Connection Charges	5	38.3	192		
9						
10	Total	$ 3,218		$ 124,992	38.8	
11						
12	**EXPENSES**					
13	Energy Purchases	$ 692	(40.2)	$ (27,818)		
14	Operating and Maintenance	893	(25.5)	(22,772)		
15	Property Taxes	128	(2.0)	(256)		
16	Carbon Tax	875	(29.1)	(25,463)		
17	GST	28	(38.8)	(1,086)		
18	PST	17	(37.1)	(631)		
19	Income Tax	129	(15.2)	(1,961)		
20						
21	Total	$ 2,762		$ (79,987)	(29.0)	
22						
23	Net Lag (Lead) Days				9.8	
24	Total Expenses				$ 2,762	
25						
26	Cash Working Capital				$ 74	

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

Line No.	Particulars	2018 Approved	2019 FORECAST at Existing Rates *	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	520	465		465	(55)	
3	Transportation Volume (TJ)	40	41		41	2	
4		560	506	-	506	(54)	Schedule 23, Line 9, Column 3
5							
6	**REVENUE AT EXISTING RATES ***						
7	Sales	$ 2,716	$ 2,889	$ -	$ 2,889	$ 173	
8	Deficiency (Surplus)	273		94	94	(179)	
9	Transportation	153	156	-	156	3	
10	Deficiency (Surplus)	20		7	7	(13)	
11	Total	3,162	3,045	101	3,146	(16)	Schedule 27, Line 15, Column 8
12				-			
13	**COST OF ENERGY ***	673	732	-	732	59	Schedule 25, Line 9, Column 3
14							
15	**MARGIN ***	2,489	2,313	101	2,414	(75)	
16							
17	**EXPENSES**						
18	O&M Expense (net)	913	892	-	892	(21)	Schedule 29, Line 24, Column 5
19	Depreciation & Amortization	514	541	-	541	27	Schedule 31, Line 9, Column 3
20	Property Taxes	139	121	-	121	(18)	Schedule 33, Line 4, Column 3
21	Deferred 2017/2018 Revenue Deficiency	146	-	-	-	(146)	
22	Other Revenue	(26)	(18)	-	(18)	8	Schedule 35, Line 4, Column 3
23	Utility Income Before Income Taxes	803	777	101	878	75	
24							
25	Income Taxes	75	75	27	102	27	Schedule 37, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 728	$ 702	$ 74	$ 776	$ 48	Schedule 41, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 11,228	$ 11,930		$ 11,932	$ 704	Schedule 2, Line 23, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.48%	5.88%		6.50%	0.02%	Schedule 41, Line 5, Column 6
31							
32	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 Rate Design Application (RDA) on July 20, 2018.						

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 FORECAST at Existing Rates *	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	465	440		440	(25)	
3	Transportation Volume (TJ)	41	41		41	-	
4		506	482	-	482	(25)	Schedule 24, Line 9, Column 3
5							
6	**REVENUE AT EXISTING RATES ***						
7	Sales	$ 2,889	$ 2,764	$ -	$ 2,764	$ (125)	
8	Deficiency (Surplus)	94		261	261	167	
9	Transportation	156	156	-	156	-	
10	Deficiency (Surplus)	7		20	20	13	
11	Total	3,146	2,920	281	3,201	55	Schedule 28, Line 15, Column 8
12				-			
13	**COST OF ENERGY ***	732	692	-	692	(40)	Schedule 26, Line 9, Column 3
14							
15	**MARGIN ***	2,414	2,228	281	2,509	95	
16							
17	**EXPENSES**						
18	O&M Expense (net)	892	893	-	893	1	Schedule 29, Line 24, Column 6
19	Depreciation & Amortization	541	590	-	590	49	Schedule 32, Line 9, Column 3
20	Property Taxes	121	128	-	128	7	Schedule 34, Line 4, Column 3
21	Deferred 2017/2018 Revenue Deficiency	-	-	-	-	-	
22	Other Revenue	(18)	(17)	-	(17)	1	Schedule 36, Line 4, Column 3
23	Utility Income Before Income Taxes	878	634	281	915	37	
24							
25	Income Taxes	102	53	76	129	27	Schedule 38, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 776	$ 581	$ 205	$ 786	$ 10	Schedule 42, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 11,932	$ 12,104		$ 12,108	$ 176	Schedule 3, Line 23, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.50%	4.80%		6.49%	-0.01%	Schedule 42, Line 5, Column 6
31							

32 * Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 Rate Design Application (RDA) on July 20, 2018.

VOLUME AND 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	**ENERGY VOLUME SOLD (TJ)**							
2	Residential							
3	Rate Schedule 1		259.9		243.9		(16.0)	
4	Commercial							
5	Rate Schedule 2		203.7		160.1		(43.6)	
6	Rate Schedule 3		56.7		61.0		4.3	
7	Industrial							
8	Rate Schedule 25		39.5		41.3		1.8	
9	Total		559.8		506.3		(53.5)	
10								
11	**REVENUE AT EXISTING RATES ***							
12	Residential							
13	Rate Schedule 1	$	1,423	$	1,504	$	81	
14	Commercial							
15	Rate Schedule 2		1,266		1,060		(206)	
16	Rate Schedule 3		300		325		25	
17	Industrial							
18	Rate Schedule 25		173		156		(17)	
19	Total	$	3,162	$	3,045	$	(117)	
20								
21	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 RDA on July 20, 2018.							

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars		2019 Forecast		2020 Forecast		Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**							
2	Residential							
3	Rate Schedule 1		243.9		236.9		(7.0)	
4	Commercial							
5	Rate Schedule 2		160.1		150.4		(9.7)	
6	Rate Schedule 3		61.0		53.1		(7.9)	
7	Industrial							
8	Rate Schedule 25		41.3		41.3		-	
9	Total		506.3		481.7		(24.6)	
10								
11	**REVENUE AT EXISTING RATES ***							
12	Residential							
13	Rate Schedule 1	$	1,504	$	1,465	$	(39)	
14	Commercial							
15	Rate Schedule 2		1,060		1,012		(48)	
16	Rate Schedule 3		325		287		(38)	
17	Industrial							
18	Rate Schedule 25		156		156		-	
19	Total	$	3,045	$	2,920	$	(125)	
20								
21	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 RDA on July 20, 2018.							

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

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 336	$ 384	$ 48	
4	Commercial				
5	Rate Schedule 2	264	252	(12)	
6	Rate Schedule 3	73	96	23	
7	Industrial				
8	Rate Schedule 25	-		-	
9	Total	$ 673	$ 732	$ 59	

COST OF ENERGY Schedule 26
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 384	$ 372	$ (12)	
4	Commercial				
5	Rate Schedule 2	252	236	(16)	
6	Rate Schedule 3	96	84	(12)	
7	Industrial				
8	Rate Schedule 25	-		-	
9	Total	$ 732	$ 692	$ (40)	

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

Line No.	Particulars	2018 Approved Margin	2019 FORECAST Margin at Existing Rates *	2019 FORECAST Effective Increase	2019 FORECAST Margin at Revised Rates	2019 FORECAST Revenue at Existing Rates *	2019 FORECAST Effective Increase	2019 FORECAST Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 1,087	$ 1,120	$ 49	$ 1,169	$ 1,504	$ 49	$ 1,553	1,945	243.9	
4	Commercial										
5	Rate Schedule 2	1,002	808	35	843	1,060	35	1,095	458	160.1	
6	Rate Schedule 3	227	229	10	239	325	10	335	19	61.0	
7	Industrial										
8	Rate Schedule 25	173	156	7	163	156	7	163	1	41.3	
9	Total Non-Bypass	$ 2,489	$ 2,313	$ 101	$ 2,414	$ 3,045	$ 101	$ 3,146	2,423	506.3	
10											
11											
12	Total Bypass & Special	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	
13											
14											
15	Total	$ 2,489	$ 2,313	$ 101	$ 2,414	$ 3,045	$ 101	$ 3,146	2,423	506.3	
16											
17	**Effective Increase**			4.37%			3.32%				
18											
19	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 Rate Design Application (RDA) on July 20, 2018.										

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 FORECAST Margin	2020 FORECAST Margin at Existing Rates *	2020 FORECAST Effective Increase	2020 FORECAST Margin at Revised Rates	2020 FORECAST Revenue at Existing Rates *	2020 FORECAST Effective Increase	2020 FORECAST Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 1,169	$ 1,093	$ 137	$ 1,230	$ 1,465	$ 137	$ 1,602	1,923	236.9	
4	Commercial										
5	Rate Schedule 2	843	776	98	874	1,012	98	1,110	466	150.4	
6	Rate Schedule 3	239	203	26	229	287	26	313	19	53.1	
7	Industrial										
8	Rate Schedule 25	163	156	20	176	156	20	176	1	41.3	
9	Total Non-Bypass	$ 2,414	$ 2,228	$ 281	$ 2,509	$ 2,920	$ 281	$ 3,201	2,409	481.7	
10											
11											
12	Total Bypass & Special	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	
13											
14											
15	Total	$ 2,414	$ 2,228	$ 281	$ 2,509	$ 2,920	$ 281	$ 3,201	2,409	481.7	
16											
17	**Effective Increase**			12.61%			9.62%				
18											
19	* Existing rates are based on Fort Nelson rate design approved in Commission Order G-135-18 FEI 2016 Rate Design Application (RDA) on July 20, 2018.										

OPERATING AND MAINTENANCE EXPENSE - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2019 and 2020
($000s)

Schedule 29

Line No.	Particulars	2017 Actual	2018 Approved	2018 Forecast	2019 Forecast	2020 Forecast	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 25	$ 19	$ 18	$ 19	$ 19	
2	MoveUP Costs	-	-	-	-	-	
3	MoveUP Customer Services Costs	-	-	-	-	-	
4	IBEW Costs	132	338	364	327	331	
5							
6	**Labour Costs**	**157**	**357**	**382**	**346**	**350**	
7							
8	Vehicle Costs	22	45	43	44	45	
9	Employee Expenses	13	30	20	20	20	
10	Materials and Supplies	8	8	8	8	8	
11	Computer Costs	-	-	-	-	-	
12	Fees and Administration Costs	495	536	508	540	535	
13	Contractor Costs	20	21	21	21	22	
14	Facilities	32	42	34	36	37	
15	Recoveries & Revenue	(2)	(2)	(2)	(2)	(2)	
16							
17	**Non-Labour Costs**	**588**	**680**	**632**	**667**	**665**	
18							
19							
20	**Total Gross O&M Expenses**	**745**	**1,037**	**1,014**	**1,013**	**1,015**	
21							
22	Less: Capitalized Overhead	(122)	(124)	(124)	(121)	(122)	
23							Schedule 21, Line 18, Column 5
24	**Total O&M Expenses**	**$ 623**	**$ 913**	**$ 890**	**$ 892**	**$ 893**	Schedule 22, Line 18, Column 5

OPERATING AND MAINTENANCE EXPENSE - ACTIVITY VIEW
FOR THE YEAR ENDING DECEMBER 31, 2019 and 2020
($000s)

Schedule 30

Line No.	Particulars	Account	2017 Actual	2018 Approved	2018 Forecast	2019 Forecast	2020 Forecast	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	110-11	$ 71	$ 111	$ 117	$ 111	$ 110	
2	Distribution Supervision Total	110-10	71	111	117	111	110	
3								
4	Operation Centre - Distribution	110-21	39	99	103	98	98	
5	Preventative Maintenance - Distribution	110-22	14	24	25	24	24	
6	Operations - Distribution	110-23	35	80	66	63	63	
7	Emergency Management - Distribution	110-24	28	55	57	54	54	
8	Field Training - Distribution	110-25	14	33	34	32	32	
9	Meter Exchange - Distribution	110-26	15	24	25	24	24	
10	Distribution Operations Total	110-20	145	315	310	295	295	
11								
12	Corrective - Distribution	110-31	28	61	64	61	61	
13	Distribution Maintenance Total	110-30	28	61	64	61	61	
14								
15	Account Services - Distribution	110-41	7	11	12	11	11	
16	Bad Debt Management - Distribution	110-42	3	7	7	7	7	
17	Distribution Meter to Cash Total	110-40	10	18	19	18	18	
18								
19	**Distribution Total**	**110**	**254**	**505**	**510**	**485**	**484**	
20								
21	**Operations Total**	**100**	**254**	**505**	**510**	**485**	**484**	
22								
23	Administration & General	540-11	-	-	-	-	-	
24	Shared Services Agreement	540-12	491	532	504	528	531	
25	Retiree Benefits	540-16	-	-	-	-	-	
26	Corporate Total	540-10	491	532	504	528	531	
27								
28	**Corporate Total**	**540**	**491**	**532**	**504**	**528**	**531**	
29								
30	**Corporate Services Total**	**500**	**491**	**532**	**504**	**528**	**531**	
31								
32	**Total Gross O&M Expenses**		**745**	**1,037**	**1,014**	**1,013**	**1,015**	
33								
34	Less: Capitalized Overhead		(122)	(124)	(124)	(121)	(122)	
35								Schedule 21, Line 18, Column 5
36	**Total O&M Expenses**		**$ 623**	**$ 913**	**$ 890**	**$ 892**	**$ 893**	Schedule 22, Line 18, Column 5

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

Schedule 31

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 416	$ 457	$ 41	Schedule 7, Line 38, Column 6
3					
4	**Amortization**				
5	Rate Base deferrals	$ 126	$ 113	$ (13)	Schedule 13, Line 22, Column 6
6	CIAC	(28)	(29)	(1)	Schedule 9, Line 9, Column 5
7		98	84	(14)	
8					
9	Total	$ 514	$ 541	$ 27	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars		2019 Forecast		2020 Forecast		Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
1	**Depreciation**							
2	Depreciation Expense	$	457	$	462	$	5	Schedule 8, Line 38, Column 6
3								
4	**Amortization**							
5	Rate Base deferrals	$	113	$	156	$	43	Schedule 14, Line 22, Column 6
6	CIAC		(29)		(28)		1	Schedule 10, Line 9, Column 5
7			84		128		44	
8								
9	Total	$	541	$	590	$	49	

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

Line No.	Particulars	2018 APPROVED	2019 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 106	$ 89	$ (17)	
2	1% In-Lieu of Municipal Taxes	33	32	(1)	
3					
4	Total	$ 139	$ 121	$ (18)	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 89	$ 92	$ 3	
2	1% In-Lieu of Municipal Taxes	32	36	4	
3					
4	Total	$ 121	$ 128	$ 7	

OTHER REVENUE Schedule 35
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 17	$ 13	$ (4)	
2	Application Charge	9	5	(4)	
3		-			
4	Total	$ 26	$ 18	$ (8)	

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 36

Line No.	Particulars	2019 Forecast	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 13	$ 12	$ (1)	
2	Application Charge	5	5	-	
3					
4	Total	$ 18	$ 17	$ (1)	

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

Line No.	Particulars	2018 Approved	2019 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 728	$ 776	$ 48	Schedule 21, Line 27, Column 5
2	Deduct: Interest on Debt	(350)	(374)	(24)	Schedule 41, Line 1+2, Column 7
3	Adjustments to Taxable Income	(166)	(126)	40	Schedule 37, Line 31
4	Accounting Income After Tax	$ 212	$ 276	$ 64	
5					
6	1 - Current Income Tax Rate	74.00%	73.00%	-1.00%	
7	Taxable Income	$ 287	$ 378	$ 91	
8					
9	Current Income Tax Rate	26.00%	27.00%	1.00%	
10	Income Tax - Current	$ 75	$ 102	$ 27	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 75	$ 102	$ 27	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 416	$ 457	$ 41	Schedule 31, Line 2, Column 3
19	Amortization of Deferred Charges	126	113	(13)	Schedule 31, Line 5, Column 3
20	Amortization of Debt Issue Expenses	2	2	-	
21	Pension Expense	55	37	(18)	
22	OPEB Expense	34	23	(11)	
23					
24	Deductions:				
25	Capital Cost Allowance	(634)	(638)	(4)	Schedule 39, Line 13, Column 6
26	CIAC Amortization	(28)	(29)	(1)	Schedule 31, Line 6, Column 3
27	Pension Contributions	(70)	(35)	35	
28	OPEB Contributions	(15)	(4)	11	
29	Overheads Capitalized Expensed for Tax Purposes	(41)	(41)	-	
30	Removal Costs	(11)	(11)	-	Schedule 13, Line 17, Column 4
31	Total	$ (166)	$ (126)	$ 40	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 776	$ 786	$ 10	Schedule 22, Line 27, Column 5
2	Deduct: Interest on Debt	(374)	(378)	(4)	Schedule 42, Line 1+2, Column 7
3	Adjustments to Taxable Income	(126)	(60)	66	Schedule 38, Line 31
4	Accounting Income After Tax	$ 276	$ 348	$ 72	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	73.00%	
7	Taxable Income	$ 378	$ 477	$ 99	
8					
9	Current Income Tax Rate	27.00%	27.00%	27.00%	
10	Income Tax - Current	$ 102	$ 129	$ 27	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 102	$ 129	$ 27	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 457	$ 462	$ 5	Schedule 32, Line 2, Column 3
19	Amortization of Deferred Charges	113	156	43	Schedule 32, Line 5, Column 3
20	Amortization of Debt Issue Expenses	2	2	-	
21	Pension Expense	37	37	-	
22	OPEB Expense	23	23	-	
23					
24	Deductions:				
25	Capital Cost Allowance	(638)	(621)	17	Schedule 40, Line 13, Column 6
26	CIAC Amortization	(29)	(28)	1	Schedule 32, Line 6, Column 3
27	Pension Contributions	(35)	(35)	-	
28	OPEB Contributions	(4)	(4)	-	
29	Overheads Capitalized Expensed for Tax Purposes	(41)	(41)	-	
30	Removal Costs	(11)	(11)	-	Schedule 14, Line 17, Column 4
31	Total	$ (126)	$ (60)	$ 66	

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

Line No.	Class	CCA Rate	12/31/2018 UCC Balance	Adjustments	2019 Additions	2019 CCA	12/31/2019 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 1,926	$ -	$ -	$ (77)	$ 1,849
2	1(b)	6%	495	-	22	(30)	487
3	2	6%	187	-	-	(11)	176
4	3	5%	10	-	-	-	10
5	8	20%	34	-	10	(8)	36
6	10	30%	10	-	-	(3)	7
7	12	100%	23	-	29	(38)	14
8	14.1 (pre 2017)	7%	25	-	-	(2)	23
9	49	8%	3,598	-	6	(288)	3,316
10	50	55%	35	-	11	(22)	24
11	51	6%	2,317	-	652	(159)	2,810
12							
13	Total		$ 8,660	$ -	$ 730	$ (638)	$ 8,752

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Class	CCA Rate	12/31/2019 UCC Balance	Adjustments	2020 Additions	2020 CCA	12/31/2020 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 1,849	$ -	$ -	$ (74)	$ 1,775
2	1(b)	6%	487	-	23	(29)	481
3	2	6%	176	-	-	(11)	165
4	3	5%	10	-	-	-	10
5	8	20%	36	-	10	(8)	38
6	10	30%	7	-	-	(2)	5
7	12	100%	14	-	28	(28)	14
8	14.1 (pre 2017)	7%	23	-	-	(2)	21
9	49	8%	3,316	-	6	(266)	3,056
10	50	55%	24	-	11	(16)	19
11	51	6%	2,810	-	540	(185)	3,165
12							
13	Total		$ 8,752	$ -	$ 618	$ (621)	$ 8,749

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

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	$ 335	$ 7,038	58.98%	5.19%	3.06%	$ 365	$ 30	Schedule 43, Line 30&32, Column 5&6&7
2	Short Term Debt	15	300	2.52%	3.10%	0.08%	9	(6)	
3	Common Equity	378	4,594	38.50%	8.75%	3.37%	402	24	
4									
5	Total	$ 728	$ 11,932	100.00%		6.50%	$ 776	$ 48	
6									
7	Cross Reference		Schedule 2, Line 23, Column 3						

Schedule 42

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Forecast Earned Return	Amount	Ratio	2020 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 365	$ 7,123	58.83%	5.17%	3.04%	$ 368	$ 3	Schedule 44, Line 30&32, Column 5&6&7
2	Short Term Debt	9	323	2.67%	3.20%	0.08%	10	1	
3	Common Equity	402	4,662	38.50%	8.75%	3.37%	408	6	
4									
5	Total	$ 776	$ 12,108	100.00%		6.49%	$ 786	$ 10	
6									
7	Cross Reference		Schedule 3, Line 23, Column 3						

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

Schedule 43

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	147,710	150,000	7.073%	10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	120,466	121,307	2.644%	3,207	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.823%	5,735	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue	November 1, 2018	November 1, 2048	148,500	150,000	3.957%	5,936	
15	2019 Medium Term Debt Issue	July 1, 2019	July 1, 2049	148,500	75,616	4.360%	3,297	
16								
17								
18	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
19	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
20								
21	LILO Obligations - Kelowna				16,320	6.936%	1,132	
22	LILO Obligations - Nelson				2,696	8.717%	235	
23	LILO Obligations - Vernon				7,895	10.108%	798	
24	LILO Obligations - Prince George				20,914	8.927%	1,867	
25	LILO Obligations - Creston				2,011	8.006%	161	
26								
27	Vehicle Lease Obligation				1,290	4.186%	54	
28								
29	Sub-Total				$ 2,643,049		$ 137,214	
30	Fort Nelson Division Portion of Long Term				$ 7,038		$ 365	
31								
32	Average Embedded Cost					5.19%		
33								
34	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 44

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	147,710	150,000	7.073%	10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	122,690	123,531	2.644%	3,266	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.823%	5,735	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue	November 1, 2018	November 1, 2048	148,500	150,000	3.957%	5,936	
15	2019 Medium Term Debt Issue	July 1, 2019	July 1, 2049	148,500	75,616	4.360%	3,297	
16	2020 Medium Term Debt Issue	July 1, 2020	July 1, 2050	148,500	75,410	4.461%	3,364	
17								
18	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
19	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
20								
21	LILO Obligations - Kelowna				15,391	6.939%	1,068	
22	LILO Obligations - Nelson				2,559	8.714%	223	
23	LILO Obligations - Vernon				7,466	10.113%	755	
24	LILO Obligations - Prince George				19,885	8.926%	1,775	
25	LILO Obligations - Creston				1,917	7.981%	153	
26								
27	Vehicle Lease Obligation				579	4.318%	25	
28								
29	Sub-Total				$ 2,717,354		$ 140,389	
30	Fort Nelson Division Portion of Long Term				$ 7,123		$ 368	
31								
32	Average Embedded Cost					5.17%		
33								
34	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

Appendix A1

CBOC REPORT

Table A1-1: Conference Board of Canada Report

January, 19,2018
Provincial Medium Term
Forecast: 20173 Run: 18
Table: 156 and 157

BRITISH COLUMBIA	**2016**	**2017**	**2018**	**2019**	**2020**
Forecasted Single-Family Housing Starts (Units)	12,278	12,084	11,788	9,481	8,939
Forecast Percent Change	20.9	(1.6)	(2.45)	(19.6)	(5.72)
Forecasted Mult-Family Housing Starts (Units)	29,565	28,916	29,405	24,452	23,258
Forecast Percent Change	38.8	(2.2)	1.7	(16.8)	(4.9)
Forecast Housing Starts Total	41,843	41,000	41,193	33,933	32,197

Appendix A2

HISTORICAL FORECAST AND CONSOLIDATED TABLES

ALSO REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

FORTIS BC™

Appendix A-2

Historical Forecast and Consolidated Tables

September 4, 2018

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2008-2017 actual data
    b. 2018 seed year data
    c. 2019-2020 forecast data
2. Percent Error
    a. 2008-2017 forecast, actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEFN Historic Customer Counts, Customer Additions, Use per Customer and Energy

FORT NELSON	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Customers										
Rate Schedule 1	1,925	1,925	1,937	1,955	1,947	1,959	1,962	1,963	1,945	1,927
Rate Schedule 2.1	414	412	421	447	443	446	446	474	478	476
Rate Schedule 2.2	28	28	28	31	31	31	31	7	7	6
Rate Schedule 25	2	2	2	2	2	2	2	2	2	1
Total Customers	**2,369**	**2,367**	**2,388**	**2,435**	**2,423**	**2,438**	**2,441**	**2,446**	**2,432**	**2,410**
Customer Additions										
Rate Schedule 1	(3)	-	12	18	8	12	3	1	(18)	(18)
Rate Schedule 2.1	6	(2)	9	26	4	3	-	28	4	(2)
Rate Schedule 2.2	(2)	-	-	3	-	-	-	(24)	-	(1)
Rate Schedule 25	-	-	-	-	-	-	-	-	(1)	-
Total Customer Additions	**1**	**(2)**	**21**	**47**	**12**	**15**	**3**	**5**	**(15)**	**(21)**
Energy (TJs)										
Rate Schedule 1	268	266	271	268	269	270	268	265	262	251
Rate Schedule 2.1	185	191	194	206	205	204	204	223	222	214
Rate Schedule 2.2	88	94	95	97	100	110	106	65	55	48
Rate Schedule 25	210	69	55	51	56	61	68	50	41	42
Total Energy (TJs)	**751**	**621**	**615**	**622**	**630**	**645**	**645**	**603**	**580**	**556**
Use Rate (GJ)										
Rate Schedule 1	139.6	138.4	140.9	137.8	138.8	138.6	136.5	135.5	134.2	129.9
Rate Schedule 2.1	448.9	464.0	468.1	475.6	465.0	460.2	455.5	482.0	465.8	447.8
Rate Schedule 2.2	3,137	3,371	3,388	3,326	3,228	3,555	3,425	6,616	7,869	8,086

Please refer to Table A2-2 for RDA Commercial Mapping

With the approval of FEI's 2016 RDA for FEFN, for the Test Years of 2019 and 2020, FEFN's commercial customers will be taking service under Rate Schedules 2 and 3 (rather than the previous Rates 2.1 and 2.2) with a separation point of 2,000 GJ per year (rather than the previous 6,000 GJ per year). FEI's forecast methods require historical demand, including the 2018 seed year, to be based on the same rate schedules as the forecast years. Therefore, in order to develop the commercial forecast for 2019 and 2020, FEI mapped the commercial customers to the new Rate Schedules 2 and 3 for the period from 2014 to 2017 using their average annual weather normalized consumption of those years. Customers with an average annual consumption of 2,000 GJs or less were mapped to Rate Schedule 2 while customers with an average annual consumption greater than 2,000 GJs were mapped to Rate Schedule 3. Table A2-2 below shows the Customer Count, Customer Additions, Use per Customer and Total Energy Demand in the previous Rate 2.1 and 2.2 commercial classes from 2014 to 2017 and the respective mapped numbers in the new Rate Schedules 2 and 3 commercial classes over the same period.

Table A2-2: FEFN Forecast Customer Counts, Customer Additions, Use per Customer and Energy

FORT NELSON	2014	2015	2016	2017	2018S	2019F	2020F
Customers							
Rate Schedule 1	1,962	1,963	1,945	1,927	1,909	1,941	1,918
Rate Schedule 2*	444	447	452	453	456	465	468
Rate Schedule 3*	20	20	20	20	20	19	19
Rate Schedule 25	2	2	2	1	1	1	1
Total Customers					**2,386**	**2,426**	**2,406**
Customer Additions							
Rate Schedule 1	-	1	(18)	(18)	(18)	32	(23)
*Rate Schedule 2**		3	5	1	3	9	3
*Rate Schedule 3**		-	-	-	-	(1)	-
Rate Schedule 25							
Total Customer Additions					**(15)**	**40**	**(20)**
Energy (TJs)							
Rate Schedule 1	268	265	262	251	245	244	237
*Rate Schedule 2**	210	195	186	182	171	160	150
*Rate Schedule 3**	91	88	82	77	71	61	53
Rate Schedule 25	68	50	41	42	42	42	42
Total Energy (TJs)					**527**	**507**	**482**
Use Rate (GJ)							
Rate Schedule 1	136.5	135.5	134.2	129.9	127.6	125.2	122.9
*Rate Schedule 2**	473.8	437.2	412.0	402.4	375.9	349.3	322.7
*Rate Schedule 3**	4,556	4,408	4,109	3,861	3,526	3,164	2,802

2014-2017 Data is mapped for forecasting purposes only.

3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEFN provides 10 years of historical demand, forecast demand and percent error for each customer class for total demand, customers, customer additions and use per customer (UPC). Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \frac{(Y_t - F_t)}{Y_t} \times 100$$

Table A2-3: FEFN Demand Variances

Rate Schedule 1 - Residential	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	291,154	272,606	263,045	258,951	273,297	274,309	270,571	268,635	267,546	261,825
Actual	268,169	266,370	271,367	267,722	269,235	270,062	267,589	265,419	262,275	251,350
Error = (ACT-FCST)	(22,985)	(6,236)	8,322	8,771	(4,063)	(4,247)	(2,982)	(3,216)	(5,271)	(10,475)
Percent Error = (Error/ACT)	-8.6%	-2.3%	3.1%	3.3%	-1.5%	-1.6%	-1.1%	-1.2%	-2.0%	-4.2%

Rate Schedule 2.1 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	209,910	186,312	181,641	182,772	203,246	207,927	208,999	208,315	208,642	211,897
Actual	184,532	191,342	193,609	205,891	205,024	204,488	203,517	222,697	221,733	214,211
Error = (ACT-FCST)	(25,378)	5,030	11,968	23,119	1,778	(3,440)	(5,482)	14,382	13,091	2,314
Percent Error = (Error/ACT)	-13.8%	2.6%	6.2%	11.2%	0.9%	-1.7%	-2.7%	6.5%	5.9%	1.1%

Rate Schedule 2.2 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	96,042	87,957	94,774	94,774	101,063	104,320	109,660	115,656	120,843	56,570
Actual	88,281	94,378	94,669	96,842	100,065	109,821	106,168	64,924	55,081	48,357
Error = (ACT-FCST)	(7,761)	6,421	(105)	2,068	(998)	5,502	(3,492)	(50,732)	(65,762)	(8,213)
Percent Error = (Error/ACT)	-8.8%	6.8%	-0.1%	2.1%	-1.0%	5.0%	-3.3%	-78.1%	-119.4%	-17.0%

Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	305,952	274,269	276,415	277,547	304,309	312,247	318,658	323,972	329,485	268,467
Actual	272,813	285,721	288,278	302,734	305,089	314,309	309,685	287,621	276,814	262,568
Error = (ACT-FCST)	(33,139)	11,452	11,863	25,187	780	2,062	(8,973)	(36,351)	(52,672)	(5,899)
Percent Error = (Error/ACT)	-12.1%	4.0%	4.1%	8.3%	0.3%	0.7%	-2.9%	-12.6%	-19.0%	-2.2%

Rate Schedule 25 - General Firm Transportation	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	276,063	239,795	58,492	58,492	54,995	54,995	67,084	55,832	49,000	39,685
Actual	209,955	68,982	54,995	51,354	55,832	60,756	67,598	49,790	41,110	41,847
Error = (ACT-FCST)	(66,108)	(170,813)	(3,496)	(7,138)	837	5,761	515	(6,042)	(7,890)	2,162
Percent Error = (Error/ACT)	-31.5%	-247.6%	-6.4%	-13.9%	1.5%	9.5%	0.8%	-12.1%	-19.2%	5.2%

Total Demand	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	873,169	786,670	597,952	594,989	632,602	641,551	656,313	648,439	646,031	569,978
Actual	750,937	621,072	614,641	621,809	630,155	645,127	644,872	602,830	580,199	555,765
Error = (ACT-FCST)	(122,232)	(165,598)	16,689	26,820	(2,447)	3,576	(11,441)	(45,609)	(65,832)	(14,212)
Percent Error = (Error/ACT)	-16.3%	-26.7%	2.7%	4.3%	-0.4%	0.6%	-1.8%	-7.6%	-11.3%	-2.6%

Table A2-4: FEFN UPC Variances

Rate Schedule 1 - Residential	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	149	140	136	133	140	140	138	136	135	133
Actual	140	138	141	138	139	139	137	136	134	130
Error = (ACT-FCST)	(9)	(2)	5	5	(1)	(1)	(1)	(1)	(1)	(3)
Percent Error = (Error/ACT)	-6.6%	-1.2%	3.6%	3.5%	-1.1%	-1.0%	-0.8%	-0.5%	-0.4%	-2.6%

Rate Schedule 2.1 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	503	474	435	435	466	465	463	453	437	444
Actual	449	464	468	476	465	460	456	482	466	448
Error = (ACT-FCST)	(54)	(10)	34	41	(1)	(5)	(7)	29	29	4
Percent Error = (Error/ACT)	-12.0%	-2.1%	7.2%	8.6%	-0.3%	-1.1%	-1.6%	6.1%	6.1%	0.8%

Rate Schedule 2.2 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	3,312	3,157	3,385	3,385	3,609	3,726	3,487	3,535	3,699	8,081
Actual	3,137	3,371	3,388	3,326	3,228	3,555	3,425	6,616	7,869	8,086
Error = (ACT-FCST)	(175)	214	3	(59)	(381)	(171)	(62)	3,081	4,169	4
Percent Error = (Error/ACT)	-5.6%	6.3%	0.1%	-1.8%	-11.8%	-4.8%	-1.8%	46.6%	53.0%	0.1%

Table A2-5: FEFN Total Customer Variances

Rate Schedule 1 - Residential	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	1,973	1,985	1,945	1,955	1,960	1,973	1,971	1,984	1,997	1,965
Actual	1,925	1,925	1,937	1,955	1,947	1,959	1,962	1,963	1,945	1,927
Error = (ACT-FCST)	(48)	(60)	(8)	0	(13)	(14)	(9)	(21)	(52)	(38)
Percent Error = (Error/ACT)	-2.5%	-3.1%	-0.4%	0.0%	-0.7%	-0.7%	-0.5%	-1.1%	-2.7%	-2.0%

Rate Schedule 2.1 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	421	426	420	422	443	454	457	468	479	478
Actual	414	412	421	447	443	446	446	474	478	476
Error = (ACT-FCST)	(7)	(14)	1	25	-	(8)	(11)	6	(1)	(2)
Percent Error = (Error/ACT)	-1.7%	-3.4%	0.2%	5.6%	0.0%	-1.8%	-2.5%	1.3%	-0.2%	-0.4%

Rate Schedule 2.2 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	29	29	28	28	28	28	32	33	34	7
Actual	28	28	28	31	31	31	31	7	7	6
Error = (ACT-FCST)	(1)	(1)	-	3	3	3	(1)	(26)	(27)	(1)
Percent Error = (Error/ACT)	-3.6%	-3.6%	0.0%	9.7%	9.7%	9.7%	-3.2%	-371.4%	-385.7%	-16.7%

Table A2-6: FEFN Customer Additions Variances

Rate Schedule 1 - Residential	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	45	9	10	10	11	13	12	13	13	1
Actual	(3)	-	12	18	8	12	3	1	(18)	(18)
Error = (ACT-FCST)	(48)	(9)	2	8	(3)	(1)	(9)	(12)	(31)	(19)
Percent Error = (Error/ACT)	1600.0%		16.7%	44.4%	-37.5%	-8.3%	-300.0%	-1200.0%	172.2%	105.6%

Rate Schedule 2.1 - Small Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	13	3	3	2	11	11	11	11	11	2
Actual	6	(2)	9	26	4	3	-	28	4	(2)
Error = (ACT-FCST)	(7)	(5)	6	24	(7)	(8)	(11)	17	(7)	(4)
Percent Error = (Error/ACT)	-116.7%	250.0%	66.7%	92.3%	-175.0%	-266.7%		60.7%	-175.0%	200.0%

Rate Schedule 2.2 - Large Commercial	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forecast	(1)	-	-	-	-	-	1	1	1	-
Actual	(2)	-	-	3	-	-	-	(24)	-	(1)
Error = (ACT-FCST)	(1)	-	-	3	-	-	(1)	(25)	(1)	(1)
Percent Error = (Error/ACT)	50.0%			100.0%				104.2%		100.0%

Appendix A3

DEMAND FORECAST METHOD

Appendix A3

Demand Forecast Method

September 4, 2018

Table of Contents

List of Tables and Figures

1. INTRODUCTION

The following table shows the high level methodology used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Time series, normalized historic UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg, historical additions	Prior year customers + customer adds	Time series, normalized historic UPC	Product of Customers and Use Rates
Industrial				Interview of single industrial customer (data gathered is identical to the Annual Industrial Survey).

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, and then describes each of FEI's forecast methods used to derive the demand forecast, in the following order:

- Residential Customer Additions
- Commercial Customer Additions
- Residential Use Rate
- Commercial Use Rate
- Residential and Commercial Demand Forecast
- Industrial Demand Forecast

2. BACKGROUND INFORMATION

2.1 *ACTUAL, SEED AND FORECAST YEARS*

FEI's demand forecasts contain data from three time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **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 2 or more years depending on the filing.
- **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 filing.

2.2 *RATE CLASSES*

As a result of the Rate Design decision the commercial customers will be moved from Rate 2.1 and 2.2 into Rate Schedules 2 and 3. To develop Rate Schedule 2 and 3 forecasts of demand for 2019F and 2020F the 2018 seed year (2018S) forecast had to also be developed using Rate Schedule 2 and 3. The historic commercial data required to develop 2018S was developed by re-mapping existing data from Rate 2.1 and 2.2 into Rate Schedule 2 and 3. This was done by determining what rate class each customer would be in under the new rate schedule definitions. The upper limit cut-off for Rate 2.1 was 6.000 GJs/year while under the new rate structure this cut-off drops to 2,000 GJs/yr. Historic weather normalized customer data was remapped based on the new cut-off. Remapped data is used throughout the method for the development of the commercial forecast. The remainder of this document will refer to Rate Schedule 2 and 3 and where historic data is involved this means remapped Rate 2.1 and 2.2 data.

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table A3-2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	

Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 25 - General Firm Transportation	This rate schedule applies to the provision of firm transportation service through the FEI system and through one meter station to one shipper.

2.3 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules 1, 2 and 3) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the "Gompertz" model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A \times e^{\left(-e^{-B \times (Avg.Monthly\ Temp. - C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C \times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared error (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The three non-linear models were tested to see which provided the best fit for each rate class and region. The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

3.1 INTRODUCTION

As shown in Table A3-1 above, the residential demand forecast is the product of the number of customers and the use rate. The forecast number of customers is determined by using the actual customer additions[1] from the most recent year, and applying a forecast growth rate for customer additions.

This section describes the residential customer additions forecast methodology, beginning with a general description and followed by a step-by-step discussion of the forecast.

3.2 DESCRIPTION OF THE METHOD

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of January 19th, 2018 Provincial Medium Term Forecast: 20173 Run: 18, Table LTPF156 and LTPF157 (see Appendix A1). The housing starts data was as follows:

Table A3-3: Housing Starts Data

Housing Type	2016	2017	2018	2019	2020
SFD	12,278	12,084	11,788	9,481	8,939
MFD	29,565	28,916	29,405	24,452	23,258
Total	41,843	41,000	41,193	33,933	32,197

From the above housing starts forecast, the 2018S SFD growth rate is calculated as follows:

$$2018S\ SFD\ Growth\ Rate = \left(\frac{11{,}788}{12{,}084}\right) - 1 = -2.4\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

[1] Customer additions or "net" customer additions is the year-over-year change in the total number of customers.

Table A3-4: Growth Rates

	2018S	2019F	2020F
SFD	-2.4%	-19.6%	-5.7%
MFD	1.7%	-16.8%	-4.9%

The following table incorporates the FEFN proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data. The 2017 actual total additions are shown on row 8, followed by the SFD and MFD proportions in rows 9 and 10. The CBOC growth rates for 2018 (rows 13 and 14) are applied to the SFD and MFD additions from rows 9 and 10 to establish the SFD and MFD growth in rows 17 and 21 respectively. The 2017A additions (rows 9 and 10) are added to the growth in rows 17 and 21 to develop the forecast in rows 18 and 22. The sub-total forecast is shown in row 24. The one time additions for the acquisition of the Prophet River First Nation distribution system are shown in row 26 for 2019F. The final forecast incorporating both the CBOC growth portion and the one-time adjustment is shown in row 27 and rounded in row 28.

Table A3-5: FEFN Residential Account Additions by SFD and MFD

	A	B	C	D	E
1	FEFN			RRA	
2	Rate 1	Actual	Seed	Forecast	Forecast
3		2017	2018	2019	2020
4	Splits				
5	SFD %	60%			
6	MFD %	40%			
7					
8	Year End	(18)			
9	SFD additions	(10.8)			
10	MFD additions	(7.2)			
11					
12	CBOC Growth Rates				
13	SFD		-2.4%	-19.6%	-5.7%
14	MFD		1.7%	-16.8%	-4.9%
15					
16	SFD				
17	Growth		(0.3)	(2.2)	(0.8)
18	Forecast		(11.1)	(13.2)	(14.0)
19					
20	MFD				
21	Growth		0.1	(1.2)	(0.4)
22	Forecast		(7.1)	(8.3)	(8.7)
23					
24	Sub-Total		(18.1)	(21.5)	(22.7)
25					
26	One time adjustment		-	53	-
27	Forecast of additions		(18.1)	31.5	(22.7)
28	**Rounded**		**(18)**	**32**	**(23)**

For example, the 2020F SFD value of -14 (E18) is derived as follows:

- 2017 Internal Split – SFD percentage = 60%
- 2017 Actual additions = -18 (column C)

1. $2017A\ Actual\ SFD = 60\% \ \times -18 = -10.8\ (B9)$
2. $2018S\ Forecast\ SFD = \ -10.8 + (-2.4\% \times -10.8) = -11.1\ (C18)$
3. $2019F\ Forecast\ SFD = -11.1 + (-19.6\% \times -11.1) = -13.2\ (D18)$
4. $2020F\ Forecast\ SFD = -13.2 + (-5.7\% \times\ -13.2) = -14\ (E18)$

Once the basic customer additions forecast is complete (row 24) the one-time adjustment of 53 residential customers in 2019 as a result of the acquisition of the Prophet River First Nation distribution system is added. This addition only affects 2019F as shown below:

$$2019F\ Forecast = -21.5 + 53 = 32\ (D28)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated using a three-year average of prior actuals additions at the region and rate class level. As discussed in section 2.2 above, remapped rate class data is used for the following calculations so all references will be to Rate Schedule 2 and 3.

The following table shows the customer additions for Rate Schedule 2.

Table A3-6: Customer Additions for Rate Schedule 2

	A	B	C	D	E	F	G	H
1	Year	Customers	Customer Additions	Average 2015-2017	Additions Forecast	One Time Adjusment	Net Additions	Customers
2	2014	444						
3	2015	447	3					
4	2016	452	5					
5	2017	453	1	3				
6	2018S				3		3	456
7	2019F				3	6	9	465
8	2020F				3		3	468

The three-year average additions was 3, so 3 net additions are forecast in each of 2018S, 2019F and 2020F.

$$2018S\ Customers = 2017\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2018S = 456 = 453 + 3$$

A one-time adjustment of 6 customers is shown in column F, row 7 as a result of the Prophet River acquisition.

The following table shows the customer additions for Rate Schedule 3.

Table A3-6: Customer Additions for Rate Schedule 3

	A	B	C	D	E	F	G	
1	Year	Customers	Customer Additions	Average 2015-2017	Additions Forecast	One Time Adjusment	Net Additions	Customers
2	2014	20						
3	2015	20	0					
4	2016	20	0					
5	2017	20	0	0				
6	2018S	20			0		0	20
7	2019F	20			0	-1	-1	19
8	2020F	19			0		0	19

The three-year average additions was 0, so 0 net additions are forecast in each of 2018S, 2019F and 2020F.

$$2018S\ Customers = 2017\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2018S = 20 = 20 + 0$$

A one-time loss of 1 customer is shown in column F, row 7 as a result of the Prophet River acquisition.

The aggregate commercial net additions are then the sum of column G from the previous two tables:

	A	G
1	Year	Net Additions
2	2014	
3	2015	
4	2016	
5	2017	
6	2018S	3
7	2019F	8
8	2020F	3

This total is also shown in Section 3, Figure 3-3.

5. RESIDENTIAL USE RATE

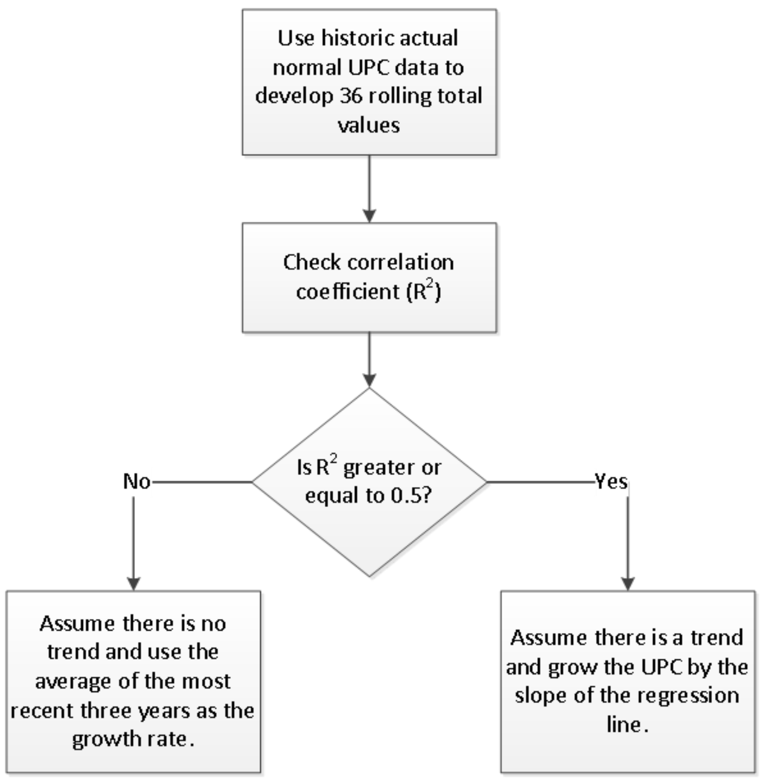
The Residential Demand Forecast is the product of the number of residential customers and the residential use rate. This section describes the method for forecasting the residential use rate.

5.1 MONTHLY WEATHER-NORMALIZED ACTUAL UPCS

FEI develops its residential use rate forecast based on four years of monthly use rates. The monthly UPC values are weather-normalized using the process described in section 2.3 above.

Four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50 percent, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50 percent or less, then a three-year average of annual growth rates is used for the forecast.

Figure A3-1: Residential Use Rate Forecast Method



The UPC method for Rate Schedule 1 is demonstrated below.

(i) ***Rate Schedule 1***

The rolling 12-month UPCs for Rate Schedule 1 were calculated as follows:

1 **Table A3-7: Rolling 12-month UPCs for Rate Schedule 1**

Date	Monthly UPC	12 month Rolling UPC	Period
01/01/2014	24.2		
01/02/2014	18.0		
01/03/2014	16.9		
01/04/2014	9.0		
01/05/2014	4.8		
01/06/2014	2.6		
01/07/2014	2.2		
01/08/2014	2.5		
01/09/2014	4.6		
01/10/2014	10.4		
01/11/2014	17.4		
01/12/2014	23.8	136.5	
01/01/2015	23.0	135.3	1
01/02/2015	19.1	136.3	2
01/03/2015	17.8	137.2	3
01/04/2015	9.8	138.0	4
01/05/2015	4.9	138.1	5
01/06/2015	2.5	138.0	6
01/07/2015	1.8	137.6	7
01/08/2015	2.2	137.3	8
01/09/2015	4.7	137.3	9
01/10/2015	9.8	136.7	10
01/11/2015	17.7	136.9	11
01/12/2015	22.3	135.5	12
01/01/2016	22.2	134.7	13
01/02/2016	18.7	134.3	14
01/03/2016	17.6	134.1	15
01/04/2016	9.3	133.6	16
01/05/2016	4.5	133.2	17
01/06/2016	2.7	133.4	18
01/07/2016	1.9	133.5	19
01/08/2016	2.5	133.8	20
01/09/2016	4.4	133.6	21
01/10/2016	9.6	133.4	22
01/11/2016	18.2	133.9	23
01/12/2016	22.6	134.2	24
01/01/2017	22.1	134.1	25
01/02/2017	18.4	133.8	26
01/03/2017	16.3	132.5	27
01/04/2017	9.0	132.3	28
01/05/2017	4.8	132.6	29
01/06/2017	2.6	132.5	30
01/07/2017	1.6	132.1	31
01/08/2017	2.2	131.8	32
01/09/2017	3.9	131.2	33
01/10/2017	10.0	131.7	34
01/11/2017	17.2	130.7	35
01/12/2017	21.8	129.9	36

2

The following summary is developed.

Table A3-8: Rate Schedule 1 UPC Calculation Summary

	A	B	C	D	E	F	G	H	I
1			**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**	**2020F**
2	**Normalized UPC**		136.5	135.5	134.2	129.9			
3	**Avg. Growth Rate**								
4	Growth Rate			-0.7%	-1.0%	-3.2%			
5	3 Yr. Avg.					-1.6%			
6	**Trend**								
7	Correlation	84%							
8	Monthly Slope	-0.20	GJ						
9	Annual Slope	-2.35	GJ						
10	**Forecast**	Use Trend					127.6	125.2	122.9

The R^2 (correlation) is 84 percent (in B7), so the trend is used, as per the flow chart above.

The 2018S forecast in G10 is developed by adding the annual slope in B9 to the 2017 actual UPC (129.9 in F2) as follows:

$$2018S\ UPC = 129.9 + (-2.35) = 127.6\ GJs$$

The 2019F forecast in H10 is calculated by adding the annual slope in B9 to the 2018S UPC (127.6 in G10) as follows:

$$2019F\ UPC = 127.6 + (-2.35) = 125.2\ GJs$$

The 2020F forecast in I10 is calculated by adding the annual slope in B9 to the 2019F UPC (125.2 in H10) as follows:

$$2020F\ UPC = 125.2 + (-2.35) = 122.9\ GJs$$

6. COMMERCIAL USE RATE

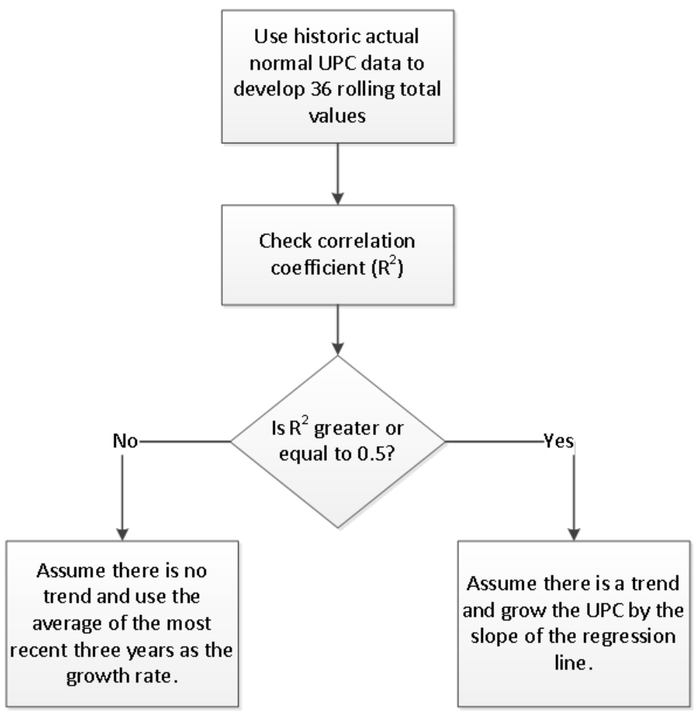
The following sections show how the use rate method works for the commercial forecast. The following method applies to Rate Schedules 2 and 3.

6.1 MONTHLY WEATHER-NORMALIZED ACTUAL UPCS

FEI develops its commercial use rate forecast based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process set out in section 2.3 above.

Four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50 percent, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50 percent or less, then a three-year average of annual growth rates is used for the forecast.

Figure A3-2: Commercial Use Rate Forecast Method



The UPC method for Rate Schedule 2 is demonstrated below.

(i) ***Rate Schedule 2***

The rolling 12-month UPCs for Rate Schedule 2 were calculated as follows:

1 **Table A3-9: Rolling 12-month UPCs for Rate Schedule 2**

Date	Monthly UPC	12 month Rolling UPC	Period
1/1/2014	89.4		
2/1/2014	64.3		
3/1/2014	59.4		
4/1/2014	31.7		
5/1/2014	16.4		
6/1/2014	6.9		
7/1/2014	7.0		
8/1/2014	7.3		
9/1/2014	14.0		
10/1/2014	34.1		
11/1/2014	61.1		
12/1/2014	82.4	473.8	
1/1/2015	79.5	464.0	1
2/1/2015	64.0	463.7	2
3/1/2015	63.5	467.8	3
4/1/2015	32.1	468.2	4
5/1/2015	14.3	466.2	5
6/1/2015	6.7	466.0	6
7/1/2015	5.0	464.0	7
8/1/2015	5.9	462.6	8
9/1/2015	11.8	460.5	9
10/1/2015	29.6	455.9	10
11/1/2015	56.3	451.2	11
12/1/2015	68.5	437.2	12
1/1/2016	70.6	428.3	13
2/1/2016	62.9	427.2	14
3/1/2016	58.0	421.7	15
4/1/2016	27.0	416.6	16
5/1/2016	12.4	414.7	17
6/1/2016	8.1	416.0	18
7/1/2016	5.4	416.4	19
8/1/2016	7.8	418.2	20
9/1/2016	11.7	418.2	21
10/1/2016	27.4	416.0	22
11/1/2016	54.4	414.1	23
12/1/2016	66.4	412.0	24
1/1/2017	73.0	414.3	25
2/1/2017	62.5	413.9	26
3/1/2017	47.4	403.3	27
4/1/2017	29.6	405.9	28
5/1/2017	13.8	407.3	29
6/1/2017	6.2	405.4	30
7/1/2017	3.9	403.9	31
8/1/2017	5.5	401.7	32
9/1/2017	9.9	399.9	33
10/1/2017	30.3	402.8	34
11/1/2017	50.4	398.8	35
12/1/2017	70.0	402.4	36

2

The following summary is developed.

Table A3-10: Rate Schedule 2 UPC Calculation Summary

	A	B	C	D	E	F	G	H	I
1			**2014**	**2015**	**2016**	**2017**	**2018S**	**2019F**	**2020F**
2	**Normalized UPC**		473.8	437.2	412.0	402.4			
3	**Avg. Growth Rate**								
4	Growth Rate			-7.7%	-5.8%	-2.3%			
5	3 Yr. Avg.					-5.3%			
6	**Trend**								
7	Correlation	88%							
8	Monthly Slope	-2.2	GJ						
9	Annual Slope	-26.6	GJ						
10	**Forecast**	Use Trend					375.9	349.3	322.7

The R^2 (correlation) is 88 percent (in B7), so the trend is used, as per the flow chart above.

The 2018S forecast in G10 is developed by adding the annual slope in B9 to the 2017 actual UPC (402.4 in F2) as follows:

$$2018S\ UPC = 402.4 + (-26.6) = 375.9\ GJs$$

The 2019F forecast in H10 is calculated by adding the annual slope in B9 to the 2018S UPC (375.9 in G10) as follows:

$$2019F\ UPC = 375.9 + (-26.6) = 349.3\ GJs$$

The 2020F forecast in I10 is calculated by adding the annual slope in B9 to the 2019F UPC (349.3 in H10) as follows:

$$2020F\ UPC = 349.3 + (-26.6) = 322.7\ GJs$$

7. UPC METHODS

The following table shows the use rate calculation method used for each rate class.

Table A3-11: Use Rate Calculation Method

Region	Rate Schedule	Method Applied
Ft Nelson	RS 1	Regression Model
	RS 2	Regression Model
	RS 3	Regression Model

8. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the simple products of the monthly customer forecast and the matching monthly use rates forecast.

9. INDUSTRIAL DEMAND FORECAST

There is only one Rate Schedule 25 customer remaining in Fort Nelson. The customer was contacted by a FEI key account manager and the customer provided a demand forecast consistent with the FEI Industrial Survey.

10. DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month and rate class to prepare the overall forecast of demand.

Appendix B

TARIFF CONTINUITY AND BILL IMPACT SCHEDULES

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2019 RATES
BCUC ORDERS G-XX-18

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	APPROVED 2018 RDA RATES[1] Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2019 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$0.3701**	**$0.0000**	**$0.3701**
3				
4	Delivery Charge per GJ	$3.512	$0.200	$3.712
5	Rider 5 RSAM per GJ	$0.391	($0.192)	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.903**	**$0.008**	**$3.911**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2019 RATES
BCUC ORDERS G-XX-18

Line No.	**RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE** Particulars	**APPROVED 2018 RDA RATES[1]** Fort Nelson	**DELIVERY MARGIN RELATED CHARGES CHANGES** Fort Nelson	**JANUARY 1, 2019 PROPOSED RATES** Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$1.2151**	**$0.0000**	**$1.2151**
3				
4	Delivery Charge per GJ	$3.781	$0.215	$3.996
5	Rider 5 RSAM per GJ	$0.391	($0.192)	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$4.172**	**$0.023**	**$4.195**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE Particulars (1)	APPROVED 2018 RDA RATES[1] Fort Nelson (2)	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson (3)	JANUARY 1, 2019 PROPOSED RATES Fort Nelson (4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$3.6845**	**$0.0000**	**$3.6845**
3				
4	Delivery Charge per GJ	$3.330	$0.162	$3.492
5	Rider 5 RSAM per GJ	$0.391	($0.192)	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.721**	**($0.030)**	**$3.691**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2019 RATES
BCUC ORDERS G-XX-18

Line No.	**RATE SCHEDULE 5** **GENERAL FIRM SERVICE** Particulars	**APPROVED 2018 RDA RATES[1]** **Fort Nelson**	**DELIVERY MARGIN RELATED CHARGES CHANGES** **Fort Nelson**	**JANUARY 1, 2019 PROPOSED RATES** **Fort Nelson**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$30.350	$1.435	$31.785
5				
6	**Delivery Charge per GJ**	$1.000	$0.053	$1.053
7	Rider 5 RSAM per GJ	$0.391	($0.192)	$0.199
8	Subtotal **Delivery Margin Related Charges per GJ**	**$1.391**	**($0.139)**	**$1.252**
9				
10	Commodity Related Charges			
11	Storage and Transport per GJ	$0.019	$0.000	$0.019
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
13	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**
14				
15				
16				
17				
18	Total Variable Cost per gigajoule	$2.962	($0.139)	$2.823

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

Line No.	RATE SCHEDULE 6: NATURAL GAS VEHICLE SERVICE Particulars	APPROVED 2018 RDA RATES[1] Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2019 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	$2.0041	$0.0000	$2.0041
3				
4	**Delivery Charge per GJ**	$2.899	$0.000	$2.899
5				
6				
7	Commodity Related Charges			
8	Storage and Transport per GJ	$0.019	$0.000	$0.019
9	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
10	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**
11				
12				
13				
14				
15	Total Variable Cost per gigajoule	$4.470	$0.000	$4.470

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

Line No.	RATE SCHEDULE 25 GENERAL FIRM SERVICE Particulars	APPROVED 2018 RDA RATES[1] Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2019 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$30.350	$1.435	$31.785
5				
6	**Delivery Charge per GJ**	$1.000	$0.053	$1.053
7				
8	**Administration Charge per Month**	$39.00	$0.00	$39.00
9				
10	**Rider 5 RSAM per GJ**	$0.391	($0.192)	$0.199
11				
12	Non-Standard Charges			
13	**Unauthorized Overrun Gas Charges**			
14	Per Gigajoule on first 5 percent of specified quantity	Station 2 Daily Price	$0.00	Station 2 Daily Price
15				
16	Per Gigajoule on all Gas over 5 percent of specified quantity	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price	$0.00	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price
17				
18	**Charge per Gigajoule of Balancing Service provided**			
19				
20	Quantities of Gas less than 10% of the Rate Schedule 25 Authorized Quantity	No charge	$0.00	No charge
21				
22				
23	Quantities of Gas over the greater of 100 Gigajoules or equal to or in excess of 10% or less than 20% of the Rate Schedule 25 Authorized Quantity	$0.25	$0.00	$0.25
24				
25				
26	Quantities of Gas over the greater of 100 Gigajoules or equal to or in excess of 20% of the Rate Schedule 25 Authorized Quantity			
27	(i) between and including April 1 and Oct 31	$0.30	$0.00	$0.30
28	(ii) between and including Nov 1 and March 31	$1.10	$0.00	$1.10
29				
30				
31	**Charge per Gigajoule of Balancing and/or Backstopping Gas**	Station 2 Daily Price	$0.00	Station 2 Daily Price
32				
33				
34				
35				
36	Total Variable Cost per gigajoule	$1.391	($0.139)	$1.252

[1] Pursuant to Commission Orders and Decision G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	APPROVED 2018 RDA RATES[1]						PROPOSED JANUARY 1, 2019 RATES						Annual Increase/Decrease		
		Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bil
1	**FORT NELSON SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$0.3701	=	$135.18		365.25	days x	$0.3701	=	$135.18		$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	125.0	GJ x	$3.512	=	439.0000		125.0	GJ x	$3.712	=	464.0000		$0.200	25.0000	3.05%
6	Rider 5 RSAM per GJ	125.0	GJ x	$0.391	=	48.8750		125.0	GJ x	$0.199	=	24.8750		($0.192)	(24.0000)	-2.93%
7	Subtotal Delivery Margin Related Charges					**$623.06**						**$624.06**			**$1.00**	**0.12%**
8																
9	Commodity Related Charges															
10	Storage and Transport per GJ	125.0	GJ x	$0.019	=	$2.38		125.0	GJ x	$0.019	=	$2.38		$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	125.0	GJ x	$1.552	=	$194.00		125.0	GJ x	$1.552	=	$194.00		$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$196.38**						**$196.38**			**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	125.0		*$6.556*		**$819.44**		125.0		*$6.564*		**$820.44**		*$0.008*	**$1.00**	**0.12%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] Pursuant to Commission Orders and Decisions G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2018[1] Quantity		Rate		Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**												
2													
3	**RATE 1 DOMESTIC SERVICE OPTION B**												
4	Monthly Charge												
5	Delivery Charge per Day	365.25	days x	$0.4588	=	$167.5767							
6	Rider 5 - RSAM per Day	365.25	days x	$0.0257	=	$9.3869							
7	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.1032	=	37.6938							
8	Minimum Monthly Charge (includes the first 2 gigajoules)			$0.5877		**$214.66**							
9													
10	Next 28 Gigajoules in any month												
11	Delivery Charge per GJ	101	GJ x	$3.557	=	$359.2570							
12	Rider 5 - RSAM per GJ	101	GJ x	0.391	=	39.4910							
13	Gas Cost Recovery Charge per GJ	101	GJ x	1.571	=	158.6710							
14	Total Charges per GJ			$5.519		**$557.42**							
15													
16	Excess of 30 Gigajoules in any month												
17	Delivery Charge per GJ	0	GJ x	$3.455	=	$0.0000							
18	Rider 5 - RSAM per GJ	0	GJ x	0.391	=	0.0000							
19	Gas Cost Recovery Charge per GJ	0	GJ x	1.571	=	0.0000							
20	Total Charges per GJ			$5.417		**$0.00**							
21													
22	**Total**	125	GJ x			**$772.08**							
23													
24	Summary of Annual Delivery and Commodity Charges												
25	**Subtotal of Delivery Charges (including RSAM**					**$575.71**							
26	**Subtotal of Commodity Charges**					**$196.36**							
27													
28													
29	**RATE SCHEDULE 1 - RESIDENTIAL SERVICE**												
30	Delivery Margin Related Charges												
31	Basic Charge per Day						365.25	days x	$0.3701	=	$135.18		
32													
33	Delivery Charge per GJ						125.0	GJ x	$3.712	=	464.0000		
34	Rider 5 RSAM per GJ						125.0	GJ x	$0.199	=	24.8750		
35	Subtotal Delivery Margin Related Charges										**$624.06**	**$48.35**	**6.26%**
36													
37	Commodity Related Charges												
38	Storage and Transport per GJ						125.0	GJ x	$0.019	=	$2.38		
39													
40	Cost of Gas (Commodity Cost Recovery Charge) per GJ						125.0	GJ x	$1.552	=	$194.00		
41	Subtotal Commodity Related Charges										**$196.38**	**$0.02**	**0.00%**
42													
43	Total *(with effective $/GJ rate)*						125.0		*$6.564*		**$820.44**	**$48.36**	**6.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders G-162-16 and G-173-16 of the FEI Fort Nelson Service Area 2017-2018 Revenue Requirements Application and G-175-17 of the 2017 Fourth Quarter Gas Cost Report for Rate Changes Effective January 1, 2018.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	APPROVED 2018 RDA RATES[1] Quantity		Rate		Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$1.2151	=	$443.82	365.25	days x	$1.2151	=	$443.82	$0.0000	$0.00	0.00%
4														
5	Delivery Charge per GJ	350.0	GJ x	$3.781	=	1,323.3500	350.0	GJ x	$3.996	=	1,398.6000	$0.215	75.2500	3.07%
6	Rider 5 RSAM per GJ	350.0	GJ x	$0.391	=	136.8500	350.0	GJ x	$0.199	=	69.6500	($0.192)	(67.2000)	-2.74%
7	Subtotal Delivery Margin Related Charges					**$1,904.02**					**$1,912.07**		**$8.05**	**0.33%**
8														
9	Commodity Related Charges													
10	Storage and Transport per GJ	350.0	GJ x	$0.019	=	$6.65	350.0	GJ x	$0.019	=	$6.65	$0.000	$0.00	0.00%
11														
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	350.0	GJ x	$1.552	=	$543.20	350.0	GJ x	$1.552	=	$543.20	$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$549.85**					**$549.85**		**$0.00**	**0.00%**
14														
15	Total *(with effective $/GJ rate)*	350.0		*$7.011*		**$2,453.87**	350.0		*$7.034*		**$2,461.92**	*$0.023*	**$8.05**	**0.33%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders and Decisions G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2018[1] Quantity		Rate		Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**												
2													
3	**RATE 2.1 GENERAL SERVICE**												
4	Monthly Charge												
5	Delivery Charge per Day	365.25	days x	$1.3358	=	$487.9010							
6	Rider 5 - RSAM per Day	365.25	days x	$0.0257	=	9.3869							
7	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.1032	=	37.6938							
8	Minimum Monthly Charge (includes the first 2 gigajoules)			$1.4647		**$534.98**							
9													
10	Next 298 Gigajoules in any month												
11	Delivery Charge per GJ	326	GJ x	$4.003	=	$1,304.9780							
12	Rider 5 - RSAM per GJ	326	GJ x	0.391	=	127.4660							
13	Gas Cost Recovery Charge per GJ	326	GJ x	1.571	=	512.1460							
14	Total Charges per GJ			$5.965		**$1,944.59**							
15													
16	Excess of 300 Gigajoules in any month												
17	Delivery Charge per GJ	0	GJ x	$3.879	=	$0.0000							
18	Rider 5 - RSAM per GJ	0	GJ x	0.391	=	0.0000							
19	Gas Cost Recovery Charge per GJ	0	GJ x	1.571	=	0.0000							
20	Total Charges per GJ			$5.841		**$0.00**							
21													
22	**Total**	350	GJ x			**$2,479.57**							
23													
24	Summary of Annual Delivery and Commodity Charges												
25	**Subtotal of Delivery Charges (including RSAM)**					**$1,929.73**							
26	**Subtotal of Commodity Charges**					**$549.84**							
27													
28													
29	**RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE**												
30	Delivery Margin Related Charges												
31	Basic Charge per Day						365.25	days x	$1.2151	=	$443.82		
32													
33	Delivery Charge per GJ						350.0	GJ x	$3.996	=	1,398.6000		
34	Rider 5 RSAM per GJ						350.0	GJ x	$0.199	=	69.6500		
35	Subtotal Delivery Margin Related Charges										**$1,912.07**	**($17.66)**	**-0.71%**
36													
37	Commodity Related Charges												
38	Storage and Transport per GJ						350.0	GJ x	$0.019	=	$6.65		
39													
40	Cost of Gas (Commodity Cost Recovery Charge) per GJ						350.0	GJ x	$1.552	=	$543.20		
41	Subtotal Commodity Related Charges										**$549.85**	**$0.01**	**0.00%**
42													
43	Total *(with effective $/GJ rate)*						350.0		*$7.034*		**$2,461.92**	**($17.65)**	**-0.71%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] Pursuant to Commission Orders G-162-16 and G-173-16 of the FEI Fort Nelson Service Area 2017-2018 Revenue Requirements Application and G-175-17 of the 2017 Fourth Quarter Gas Cost Report for Rate Changes Effective January 1, 2018.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	APPROVED 2018 RDA RATES[1] Quantity		Rate		Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1	**FORT NELSON SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$3.6845	=	$1,345.76	365.25	days x	$3.6845	=	$1,345.76	$0.0000	$0.00	0.00%
4														
5	Delivery Charge per GJ	3,165.0	GJ x	$3.330	=	10,539.4500	3,165.0	GJ x	$3.492	=	11,052.1800	$0.162	512.7300	2.83%
6	Rider 5 RSAM per GJ	3,165.0	GJ x	$0.391	=	1,237.5150	3,165.0	GJ x	$0.199	=	629.8350	($0.192)	(607.6800)	-3.36%
7	Subtotal Delivery Margin Related Charges					**$13,122.73**					**$13,027.78**		**($94.95)**	**-0.52%**
8														
9	Commodity Related Charges													
10	Storage and Transport per GJ	3,165.0	GJ x	$0.019	=	$60.14	3,165.0	GJ x	$0.019	=	$60.14	$0.000	$0.00	0.00%
11														
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,165.0	GJ x	$1.552	=	$4,912.08	3,165.0	GJ x	$1.552	=	$4,912.08	$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$4,972.22**					**$4,972.22**		**$0.00**	**0.00%**
14														
15	Total *(with effective $/GJ rate)*	3,165.0		*$5.717*		**$18,094.95**	3,165.0		*$5.687*		**$18,000.00**	*($0.030)*	**($94.95)**	**-0.52%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] Pursuant to Commission Orders and Decisions G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2018[1]				PROPOSED JANUARY 1, 2019 RATES				Annual Increase/Decrease	
		Quantity		Rate	Annual $	Quantity		Rate	Annual $	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**										
2											
3	**RATE 2.2 GENERAL SERVICE**										
4	Monthly Charge										
5	Delivery Charge per Day	365.25	days x	$1.3358 =	$487.9010						
6	Rider 5 - RSAM per Day	365.25	days x	$0.0257 =	9.3869						
7	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.1032 =	37.6938						
8	Minimum Monthly Charge (includes the first 2 gigajoules)			$1.4647	**$534.98**						
9											
10	Next 298 Gigajoules in any month										
11	Delivery Charge per GJ	3,141	GJ x	$4.003 =	$12,573.4230						
12	Reserved for Future Use	3,141	GJ x	0.391 =	1,228.1310						
13	Gas Cost Recovery Charge per GJ	3,141	GJ x	1.571 =	4,934.5110						
14	Total Charges per GJ			$5.965	**$18,736.07**						
15											
16	Excess of 300 Gigajoules in any month										
17	Delivery Charge per GJ	0	GJ x	$3.879 =	$0.0000						
18	Reserved for Future Use	0	GJ x	0.391 =	0.0000						
19	Gas Cost Recovery Charge per GJ	0	GJ x	1.571 =	0.0000						
20	Total Charges per GJ			$5.841	**$0.00**						
21											
22	**Total**	3,165	GJ		**$19,271.05**						
23											
24	Summary of Annual Delivery and Commodity Charges										
25	**Subtotal of Delivery Charges (including RSAM**				**$14,298.84**						
26	**Subtotal of Commodity Charges**				**$4,972.20**						
27											
28											
29	**RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE**										
30	Delivery Margin Related Charges										
31	Basic Charge per Day					365.25	days x	$3.6845 =	$1,345.76		
32											
33	Delivery Charge per GJ					3,165.0	GJ x	$3.492 =	11,052.1800		
34	Rider 5 RSAM per GJ					3,165.0	GJ x	$0.199 =	629.8350		
35	Subtotal Delivery Margin Related Charges								**$13,027.78**	**($1,271.06)**	**-6.60%**
36											
37	Commodity Related Charges										
38	Storage and Transport per GJ					3,165.0	GJ x	$0.019 =	$60.14		
39											
40	Cost of Gas (Commodity Cost Recovery Charge) per GJ					3,165.0	GJ x	$1.552 =	$4,912.08		
41	Subtotal Commodity Related Charges								**$4,972.22**	**$0.02**	**0.00%**
42											
43	Total *(with effective $/GJ rate)*					3,165.0		*$5.687*	**$18,000.00**	**($1,271.05)**	**-6.60%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders G-162-16 and G-173-16 of the FEI Fort Nelson Service Area 2017-2018 Revenue Requirements Application and G-175-17 of the 2017 Fourth Quarter Gas Cost Report for Rate Changes Effective January 1, 2018.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-4-18 G-135-18
RATE SCHEDULE 25 - GENERAL FIRM TRANSPORTATION SERVICE

Line No.	Particular	APPROVED 2018 RDA RATES[1] Quantity			Rate		Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity			Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bil
1	**FORT NELSON SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Month	12	months	x	$600.00	=	**$7,200.00**	12	months	x	$600.00	=	**$7,200.00**	$0.00	**$0.00**	**0.00%**
4																
5	Administration Charge per Month	12	months	x	$39.00	=	**$468.00**	12	months	x	$39.00	=	**$468.00**	$0.00	**$0.00**	**0.00%**
6																
7	Demand Charge per Month per GJ	292.7	GJ	x	$30.350	=	**$106,601.34**	292.7	GJ	x	$31.785	=	**$111,641.63**	$1.435	**$5,040.29**	**2.93%**
8																
9	Delivery Charge per GJ	41,500.0	GJ	x	$1.000	=	$41,500.0000	41,500.0	GJ	x	$1.053	=	$43,699.5000	$0.053	$2,199.5000	1.28%
10	Rider 5 RSAM per GJ	41,500.0	GJ	x	$0.391	=	16,226.5000	41,500.0	GJ	x	$0.199	=	8,258.5000	($0.192)	(7,968.0000)	-4.63%
11	Subtotal Delivery Margin Related Charges						**$57,726.50**						**$51,958.00**		**($5,768.50)**	**-3.35%**
12																
13	Total *(with effective $/GJ rate)*	41,500.0			*$4.144*		**$171,995.84**	41,500.0			*$4.127*		**$171,267.63**	*($0.018)*	**($728.21)**	**-0.42%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders and Decisions G-4-18 and G-135-18 of the 2016 FEI Rate Design Application (RDA) for Fort Nelson.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-4-18 G-135-18

RATE SCHEDULE 25 - GENERAL FIRM TRANSPORTATION SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2018[1] Quantity	Rate	Annual $	PROPOSED JANUARY 1, 2019 RATES Quantity	Rate	Annual $	Annual Increase/Decrease Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**								
2									
3	**RATE SCHEDULE 25 TRANSPORTATION SERVICE**								
4	Transportation Delivery Charges								
5									
6	Delivery Charge per Gigajoule								
7	i) First 20 Gigajoules	240 GJ x	$4.522 :	$1,085.2800					
8	ii) Next 260 Gigajoules	3,120 GJ x	$4.201 :	13,107.1200					
9	iii) Excess over 280 Gigajoules	38,140 GJ x	$3.450 :	131,583.0000					
10	iv) Minimum Delivery Charge per month	12 months x	$1,826.000	-					
11									
12	Administration Charge per month	12 months x	$202.00 :	$2,424.00					
13									
14	Rider 5: RSAM per GJ	41,500 GJ x	$0.391 :	$16,226.5000					
15									
16	**Total Transportation Delivery & Administration Charges**	41,500 GJ x	*$3.962*	**$164,425.90**					
17									
18									
19	**RATE SCHEDULE 25 - GENERAL FIRM TRANSPORTATION SERVICE**								
20	Delivery Margin Related Charges								
21	Basic Charge per Month				12 months x	$600.00 =	**$7,200.00**		
22									
23	Administration Charge per Month				12 months x	$39.00 =	**$468.00**		
24									
25	Demand Charge per Month per GJ				292.7 GJ x	$31.785 =	**$111,641.63**		
26									
27	Delivery Charge per GJ				41,500.0 GJ x	$1.053 =	$43,699.5000		
28	Rider 5 RSAM per GJ				41,500.0 GJ x	$0.199 =	8,258.5000		
29	Subtotal Delivery Margin Related Charges						**$51,958.00**		
30									
31	Total *(with effective $/GJ rate)*				41,500.0	*$4.127*	**$171,267.63**	**$6,841.73**	**4.16%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders G-162-16 and G-173-16 of the FEI Fort Nelson Service Area 2017-2018 Revenue Requirements Application.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2020 RATES
BCUC ORDERS G-XX-18

APPENDIX B2
PAGE 1
SCHEDULE 1

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	JANUARY 1, 2019 PROPOSED RATES Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2020 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$0.3701**	**$0.0000**	**$0.3701**
3				
4	Delivery Charge per GJ	$3.712	$0.381	$4.093
5	Rider 5 RSAM per GJ	$0.199	$0.000	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.911**	**$0.381**	**$4.292**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2020 RATES
BCUC ORDERS G-XX-18

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	JANUARY 1, 2019 PROPOSED RATES Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2020 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$1.2151**	**$0.0000**	**$1.2151**
3				
4	Delivery Charge per GJ	$3.996	$0.439	$4.435
5	Rider 5 RSAM per GJ	$0.199	$0.000	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$4.195**	**$0.439**	**$4.634**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2020 RATES
BCUC ORDERS G-XX-18

APPENDIX B2
PAGE 3
SCHEDULE 3

Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**JANUARY 1, 2019 PROPOSED RATES** Fort Nelson	**DELIVERY MARGIN RELATED CHARGES CHANGES** Fort Nelson	**JANUARY 1, 2020 PROPOSED RATES** Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$3.6845**	**$0.0000**	**$3.6845**
3				
4	Delivery Charge per GJ	$3.492	$0.329	$3.821
5	Rider 5 RSAM per GJ	$0.199	$0.000	$0.199
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.691**	**$0.329**	**$4.020**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport per GJ	$0.019	$0.000	$0.019
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
12	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2020 RATES
BCUC ORDERS G-XX-18

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	JANUARY 1, 2019 PROPOSED RATES Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2020 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$31.785	$2.664	$34.449
5				
6	**Delivery Charge per GJ**	$1.053	$0.088	$1.141
7	Rider 5 RSAM per GJ	$0.199	$0.000	$0.199
8	Subtotal **Delivery Margin Related Charges per GJ**	**$1.252**	**$0.088**	**$1.340**
9				
10	Commodity Related Charges			
11	Storage and Transport per GJ	$0.019	$0.000	$0.019
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
13	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**
14				
15				
16				
17				
18	Total Variable Cost per gigajoule	$2.823	$0.088	$2.911

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2020 RATES
BCUC ORDERS G-XX-18

Line No.	RATE SCHEDULE 6: NATURAL GAS VEHICLE SERVICE Particulars	JANUARY 1, 2019 PROPOSED RATES Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2020 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	$2.0041	$0.0000	$2.0041
3				
4	**Delivery Charge per GJ**	$2.899	$0.000	$2.899
5				
6				
7	Commodity Related Charges			
8	Storage and Transport per GJ	$0.019	$0.000	$0.019
9	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$1.552	$0.000	$1.552
10	Subtotal **of Commodity Related Charges per GJ**	**$1.571**	**$0.000**	**$1.571**
11				
12				
13				
14				
15	Total Variable Cost per gigajoule	$4.470	$0.000	$4.470

Line No.	RATE SCHEDULE 25 GENERAL FIRM SERVICE Particulars	JANUARY 1, 2019 PROPOSED RATES Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	JANUARY 1, 2020 PROPOSED RATES Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$31.785	$2.664	$34.449
5				
6	**Delivery Charge per GJ**	$1.053	$0.088	$1.141
7				
8	**Administration Charge per Month**	$39.00	$0.00	$39.00
9				
10	**Rider 5 RSAM per GJ**	$0.199	$0.000	$0.199
11				
12	Non-Standard Charges			
13	**Unauthorized Overrun Gas Charges**			
14	Per Gigajoule on first 5 percent of specified quantity	Station 2 Daily Price	$0.00	Station 2 Daily Price
15				
16	Per Gigajoule on all Gas over 5 percent of specified quantity	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price	$0.00	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price
17				
18	**Charge per Gigajoule of Balancing Service provided**			
19				
20	Quantities of Gas less than 10% of the Rate Schedule 25 Authorized Quantity	No charge	$0.00	No charge
21				
22				
23	Quantities of Gas over the greater of 100 Gigajoules or equal to or in excess of 10% or less than 20% of the Rate Schedule 25 Authorized Quantity	$0.25	$0.00	$0.25
24				
25				
26	Quantities of Gas over the greater of 100 Gigajoules or equal to or in excess of 20% of the Rate Schedule 25 Authorized Quantity			
27	(i) between and including April 1 and Oct 31	$0.30	$0.00	$0.30
28	(ii) between and including Nov 1 and March 31	$1.10	$0.00	$1.10
29				
30				
31	**Charge per Gigajoule of Balancing and/or Backstopping Gas**	Station 2 Daily Price	$0.00	Station 2 Daily Price
32				
33				
34				
35				
36	Total Variable Cost per gigajoule	$1.252	$0.088	$1.340

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	JANUARY 1, 2019PROPOSED RATES						PROPOSED JANUARY 1, 2020 RATES						Annual Increase/Decrease		
1	**FORT NELSON SERVICE AREA**	Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$0.3701	=	$135.18		365.25	days x	$0.3701	=	$135.18		$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	125.0	GJ x	$3.712	=	464.0000		125.0	GJ x	$4.093	=	511.6250		$0.381	47.6250	5.80%
6	Rider 5 RSAM per GJ	125.0	GJ x	$0.199	=	24.8750		125.0	GJ x	$0.199	=	24.8750		$0.000	0.0000	0.00%
7	Subtotal Delivery Margin Related Charges					**$624.06**						**$671.68**			**$47.62**	**5.80%**
8																
9	Commodity Related Charges															
10	Storage and Transport per GJ	125.0	GJ x	$0.019	=	$2.38		125.0	GJ x	$0.019	=	$2.38		$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	125.0	GJ x	$1.552	=	$194.00		125.0	GJ x	$1.552	=	$194.00		$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$196.38**						**$196.38**			**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	125.0		*$6.564*		**$820.44**		125.0		*$6.944*		**$868.06**		*$0.381*	**$47.62**	**5.80%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

[1] *Pursuant to Commission Orders and Decisions G-4-18 and G-135-18 of the 2016 FEI Rate Design Application.*

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18

RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	JANUARY 1, 2019PROPOSED RATES						PROPOSED JANUARY 1, 2020 RATES						Annual Increase/Decrease		
		Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$1.2151	=	$443.82		365.25	days x	$1.2151	=	$443.82		$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	350.0	GJ x	$3.996	=	1,398.6000		350.0	GJ x	$4.435	=	1,552.2500		$0.439	153.6500	6.24%
6	Rider 5 RSAM per GJ	350.0	GJ x	$0.199	=	69.6500		350.0	GJ x	$0.199	=	69.6500		$0.000	0.0000	0.00%
7	Subtotal Delivery Margin Related Charges					**$1,912.07**						**$2,065.72**			**$153.65**	**6.24%**
8																
9	Commodity Related Charges															
10	Storage and Transport per GJ	350.0	GJ x	$0.019	=	$6.65		350.0	GJ x	$0.019	=	$6.65		$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	350.0	GJ x	$1.552	=	$543.20		350.0	GJ x	$1.552	=	$543.20		$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$549.85**						**$549.85**			**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	350.0		*$7.034*		**$2,461.92**		350.0		*$7.473*		**$2,615.57**		*$0.439*	**$153.65**	**6.24%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-XX-18
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	JANUARY 1, 2019PROPOSED RATES					PROPOSED JANUARY 1, 2020 RATES					Annual Increase/Decrease		
1	**FORT NELSON SERVICE AREA**	Quantity		Rate		Annual $	Quantity		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bil
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$3.6845	=	$1,345.76	365.25	days x	$3.6845	=	$1,345.76	$0.0000	$0.00	0.00%
4														
5	Delivery Charge per GJ	3,165.0	GJ x	$3.492	=	11,052.1800	3,165.0	GJ x	$3.821	=	12,093.4650	$0.329	1,041.2850	5.78%
6	Rider 5 RSAM per GJ	3,165.0	GJ x	$0.199	=	629.8350	3,165.0	GJ x	$0.199	=	629.8350	$0.000	0.0000	0.00%
7	Subtotal Delivery Margin Related Charges					**$13,027.78**					**$14,069.06**		**$1,041.28**	**5.78%**
8														
9	Commodity Related Charges													
10	Storage and Transport per GJ	3,165.0	GJ x	$0.019	=	$60.14	3,165.0	GJ x	$0.019	=	$60.14	$0.000	$0.00	0.00%
11														
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,165.0	GJ x	$1.552	=	$4,912.08	3,165.0	GJ x	$1.552	=	$4,912.08	$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$4,972.22**					**$4,972.22**		**$0.00**	**0.00%**
14														
15	Total *(with effective $/GJ rate)*	3,165.0		*$5.687*		**$18,000.00**	3,165.0		*$6.016*		**$19,041.28**	*$0.329*	**$1,041.28**	**5.78%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDERS G-4-18 G-135-18
RATE SCHEDULE 25 - GENERAL FIRM TRANSPORTATION SERVICE

Line No.	Particular	JANUARY 1, 2019PROPOSED RATES						PROPOSED JANUARY 1, 2020 RATES						Annual Increase/Decrease		
		Quantity			Rate		Annual $	Quantity			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bil
1	**FORT NELSON SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Month	12	months	x	$600.00	=	**$7,200.00**	12	months	x	$600.00	=	**$7,200.00**	$0.00	**$0.00**	**0.00%**
4																
5	Administration Charge per Month	12	months	x	$39.00	=	**$468.00**	12	months	x	$39.00	=	**$468.00**	$0.00	**$0.00**	**0.00%**
6																
7	Demand Charge per Month per GJ	292.7	GJ	x	$31.785	=	**$111,641.63**	292.7	GJ	x	$34.449	=	**$120,998.67**	$2.664	**$9,357.04**	**5.46%**
8																
9	Delivery Charge per GJ	41,500.0	GJ	x	$1.053	=	$43,699.5000	41,500.0	GJ	x	$1.141	=	$47,351.5000	$0.088	$3,652.0000	2.13%
10	Rider 5 RSAM per GJ	41,500.0	GJ	x	$0.199	=	8,258.5000	41,500.0	GJ	x	$0.199	=	8,258.5000	$0.000	0.0000	0.00%
11	Subtotal Delivery Margin Related Charges						**$51,958.00**						**$55,610.00**		**$3,652.00**	**2.13%**
12																
13	Total *(with effective $/GJ rate)*	41,500.0			*$4.127*		**$171,267.63**	41,500.0			*$4.440*		**$184,276.67**	*$0.313*	**$13,009.04**	**7.60%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

Appendix C

PROFIT RIVER FIRST NATION LETTER OF SUPPORT

PROPHET RIVER FIRST NATION

telephone: (250) 773-6555
fax: (250) 773-6556

Box 3250
Fort Nelson, BC V0C 1R0

August 28, 2018

British Columbia Utilities Commission
900 Howe St. Vancouver, BC V6Z 2S9
Telephone: (604) 660-4700

Dear Sir or Mandam,

Prophet River First Nation started a formal request for Fortis Gas to take the distribution station back in February 2016. The gas utilities will need to be directly metered the individual homes and commercial buildings. The community comprehensive plan that displays five years of growth the community is planning. We have the land use plan, highway commercial development plan, and economic development plan to display our commitment to growth and creating independent sustainable community that can offer basic needs services to our members.

Chief, Council, Management and Administration are all in full support of Fortis Gas acquiring the distribution system. If you require any further information, please feel free to contact us.
Contacts for Prophet River First Nation:

Chief Kirk Tsakoza	Email: Kirk.Tsakoza@prophetriverfn.ca
Councillor Bev Stager	Email: Beverly.Stager@prophetriverfn.ca
Councillor Jackie Reno	Email: Jackie.Reno@prophetriverfn.ca
Band Manager Shelley Ergang	Email: Shelley.Ergang@prophetriverfn.ca
Capital Works Manager Andy Calahisen	Email: Andy.Calahisen@prophetriverfn.ca
Housing Coordinator Richard Chipesia	Email: Richard.Chipesia@prophetriverfn.ca

Sincerely;
Shelley Ergang
Band Manager
Prophet River First Nation

Shelley Ergang

Appendix D

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of 2019-2020 Revenue Requirements and Rates
for the Fort Nelson Service Area

BEFORE:
Panel Chair/Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 4, 2018, FortisBC Energy Inc. (FEI) submitted its 2019-2020 Revenue Requirements and Rates Application for the Fort Nelson Service Area (Application) with the British Columbia Utilities Commission (Commission) pursuant to sections 45, 46, 59 to 61, and 89 of the *Utilities Commission Act* (UCA), seeking, among other things, Commission approval of delivery rates for the 2019 and 2020 (Test Period);

B. Based on the forecast energy demand in the Fort Nelson Service Area, the forecast revenue at the 2018 approved rates from FEI's 2016 Rate Design Application (RDA) for the Fort Nelson Service Area per Commission Order G-135-18 is not sufficient to recover the cost to serve the Fort Nelson Service Area over the Test Period;

C. FEI has calculated a revenue deficiency of $101 thousand in 2019 and a further revenue deficiency of $180 thousand in 2020, which would result in a delivery rate increase of approximately 4.37 percent in 2019 and a further delivery rate increase of approximately 8.24 percent in 2020;

D. In the Application, FEI sought approval of an interim, refundable delivery rate increase of 4.37 percent effective January 1, 2019, and approval of an interim Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider of $0.199 per GJ effective January 1, 2019;

E. In the Application, FEI also seeks approval of the following:

   1. a permanent delivery rate increase of 4.37 percent effective January 1, 2019, to recover the forecast revenue deficiency of $101 thousand in 2019;

2. a permanent delivery rate increase of 8.24 percent (cumulative increase of 12.61 percent over the Test Period), effective January 1, 2020, to recover the forecast revenue deficiency of $180 thousand in 2020 (cumulative $281 thousand over the Test Period);

3. the setting of the RSAM rate rider to $0.199 per GJ (a decrease of $0.192 per GJ compared to 2018) on a permanent basis, effective January 1, 2019, as set out in Section 3.4, Table 3-3;

4. the following deferral account requests are approved:

    i. Creation of a rate base deferral account for the 2019-2020 Revenue Requirement Application costs with an amortization period of two years beginning 2019;

    ii. Amortization of the 2017 Rate Design Application deferral account approved in Commission Order G-162-16 over a five-year period beginning in 2019; and

    iii. Continue to delay disposition of the non-rate base Fort Nelson First Nation Right-of-Way Agreement deferral account to the next revenue requirement proceeding.

5. A Certificate of Public Convenience and Necessity (CPCN) for an extension of FEFN's distribution system resulting from its purchase of the gas distribution assets of the Prophet River First Nation as described in Section 10, with 53 residential and six commercial properties currently attached to the system (the Prophet River Extension).

F. FEI has proposed a written hearing process for review of the Application.

G. The Commission considers establishing a regulatory timetable for the review of the Application to be warranted and that interim rates should be approved.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. Pursuant to section 89 of the *Utilities Commission Act*, the Commission approves a 4.37 percent increase in Fort Nelson Service Area delivery rates, as set out in Appendix B of the Application and an RSAM rider set at $0.199 per GJ, on an interim and refundable basis, effective January 1, 2019.

2. A written public hearing process is established for the review of the Application in accordance with the regulatory timetable set out in Appendix A to this order.

3. By no later than September 28, 2018, FEI is to publish the Public Notice attached as Appendix B to this Order, in display-ad format, in the appropriate local news publications to provide adequate notice to the public in the Fort Nelson Service Area.

4. As soon as is reasonably possible, FEI is directed to publish the Application, this order, and the regulatory timetable on its website and to provide a copy of the Application and this order, electronically where possible, to all parties who participated in the Fort Nelson 2017-2018 Revenue Requirements and Rates Application proceeding.

5. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the Regulatory Timetable attached as Appendix A to this order, and in accordance with the Commission's Rules of Practice and Procedure attached to Order G-1-16.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of [Month Year].

BY ORDER

Original signed by:

(X. X. last name)
Commissioner

Attachments

FortisBC Energy Inc.
Application for Approval of 2019-2020 Revenue Requirements and Rates
for the Fort Nelson Service Area

REGULATORY TIMETABLE

ACTION	DATE (2018)
FEI publishes Public Notice	By the week of September 24
Intervener registration deadline	Wednesday, October 10
Commission and Intervener Information Request (IR) No. 1	Wednesday, October 24
Filing of Participant Assistance/Cost Award Budgets	Wednesday, October 31
FEI Responses to IR No. 1	Monday, November 19
FEI Written Final Argument	Wednesday, December 5
Intervener Written Final Arguments	Wednesday, December 19
ACTION	**DATE (2019)**
FEI Written Reply Argument	Wednesday, January 9

PUBLIC NOTICE

Application by FortisBC Energy Inc. for Approval of 2019-2020 Revenue Requirements and Rates for the Fort Nelson Service Area

On August 29, 2018, FortisBC Energy Inc. applied to the British Columbia Utilities Commission (Commission), pursuant to section(s) 46, 46, and 59 to 61 of the *Utilities Commission Act,* for approval of its 2019 and 2020 revenue requirements and rates application for the Fort Nelson Service Area (FEFN), seeking, among other things, Commission approval to increase delivery rates. FEI is seeking a delivery rate increase of 4.37 percent effective January 1, 2019, and a further delivery rate increase of 8.24 percent effective January 1, 2020, for the Fort Nelson Service Area (Application).

HOW TO PARTICIPATE

There are a number of ways to participate in a matter before the BCUC:

- **Submit a letter of comment**
- **Register as an interested party**
- **Request intervener status**

For more information, or to find the forms for any of the options above, please visit our website or contact us at the information below.

http://www.bcuc.com/forms/request-to-intervene.aspx

All submissions received, including letters of comment, are placed on the public record, posted on the BCUC's website and provided to the Panel and all participants in the proceeding.

NEXT STEPS

Intervener registration Persons who are directly or sufficiently affected by the Commission's decision or have relevant information or expertise, and that wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by **Wednesday, October 10, 2018**.

GET MORE INFORMATION

All documents filed on the public record are available on the "Current Proceedings" page of the BCUC's website at *www.bcuc.com*.

If you would like to review the material in hard copy, or if you have any other inquiries, please contact Patrick Wruck, Commission Secretary, at the following contact information.

British Columbia Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3

E: Commission.Secretary@bcuc.com

P: 604.660.4700

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of 2019-2020 Revenue Requirements and Rates
for the Fort Nelson Service Area

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 4, 2018, FortisBC Energy Inc. (FEI) submitted its 2019-2020 Revenue Requirements and Rates Application for the Fort Nelson Service Area (Application) with the British Columbia Utilities Commission (Commission) pursuant to sections 45, 46, 59 to 61, and 89 of the *Utilities Commission Act (UCA)*, seeking, among other things, Commission approval of delivery rates for 2019 and 2020 (Test Period);

B. Based on the forecast energy demand in the Fort Nelson Service Area, the forecast revenue at the 2018 approved rates from FEI's 2016 Rate Design Application (RDA) for the Fort Nelson Service Area per Commission Order G-135-18 is not sufficient to recover the cost to serve the Fort Nelson Service Area over the Test Period;

C. FEI has calculated a revenue deficiency of $101 thousand in 2019 and a further revenue deficiency of $180 thousand in 2020, which would result in a delivery rate increase of approximately 4.37 percent in 2019 and a further delivery rate increase of approximately 8.24 percent in 2020;

D. In the Application, FEI sought approval of an interim, refundable delivery rate increase of 4.37 percent effective January 1, 2019, and approval of an interim Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider of $0.199 per GJ effective January 1, 2019;

E. On September XX, 2019, the Commission issued Order G-XX-XX approving interim rates, on a refundable basis, as applied for, effective January 1, 2019;

F. In the Application, FEI sought approvals as follows:

   1. a permanent delivery rate increase of 4.37 percent effective January 1, 2019, to recover the forecast revenue deficiency of $101 thousand in 2019;

   2. a permanent delivery rate increase of 8.24 percent (cumulative increase of 12.61 percent over the Test Period), effective January 1, 2020, to recover the forecast revenue deficiency of $180 thousand in 2020 (cumulative $281 thousand over the Test Period);

   3. the setting of the RSAM rate rider to $0.199 per GJ (a decrease of $0.192 per GJ compared to 2018) on a permanent basis, effective January 1, 2019, as set out in Section 3.4, Table 3-3;

   4. the following deferral account requests:

      i. Creation of a rate base deferral account for the 2019-2020 Revenue Requirement Application costs with an amortization period of two years beginning 2019;

      ii. The amortization of the 2017 Rate Design Application deferral account approved in Commission Order G-162-16 over a five-year period beginning in 2019; and

      iii. Continue to delay disposition of the non-rate base Fort Nelson First Nation Right-of-Way Agreement deferral account to the next revenue requirement proceeding.

   5. A Certificate of Public Convenience and Necessity (CPCN) for an extension of FEFN's distribution system resulting from its purchase of the gas distribution assets of the Prophet River First Nation as described in Section 10, with 53 residential and six commercial properties currently attached to the system (the Prophet River Extension).

G. The Commission has reviewed and considered the Application and determines that the Application should be approved.

NOW THEREFORE the Commission orders as follows:

1. FortisBC Energy Inc.'s requested delivery rate increases of 4.37 percent effective January 1, 2019 and 8.24 percent effective January 1, 2020 for the Fort Nelson Service Area are approved on a permanent basis.

2. The RSAM rate rider is approved on a permanent basis at $0.199 per GJ effective January 1, 2019.

3. The following deferral account requests are approved, as described in Section 8.4:

   a. The creation of a rate base deferral account for the 2019-2020 Revenue Requirement Application costs with an amortization period of two years beginning 2019;

   b. The amortization of the 2017 Rate Design Application deferral account approved in Commission Order G-162-16 over a five-year period beginning in 2019; and

   c. The delay of the disposition of the non-rate base Fort Nelson First Nation Right-of-Way Agreement deferral account to the next revenue requirement proceeding.

4. FEI is granted a CPCN for the Prophet River Extension.

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