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July 20, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

2023 Cost of Service Allocation (COSA) Study and Application for Approval of Revenue Rebalancing (Application)

FEI hereby submits to the British Columbia Utilities Commission its 2023 Cost of Service Allocation Study (2023 COSA). Based on the results of the 2023 COSA, FEI seeks approval, pursuant to sections 59 to 61 of the *Utilities Commission Act*, of implementing rate changes, effective January 1, 2025, as a result of revenue rebalancing requests contained in the attached Application.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (Email only): Registered Interveners in the proceedings for:
- FEI's 2016 Rate Design Application
- FEI's Transportation Service Report
- FEI's Annual Review of 2023 Delivery Rates

FORTISBC ENERGY INC.

2023 Cost of Service Allocation (COSA) Study and Application for Approval of Revenue Rebalancing

July 20, 2023

Table of Contents

List of Appendices

Index of Tables

Index of Figures

1. EXECUTIVE SUMMARY

In its Decision and Order G-4-18, dated January 9, 2018 (2016 COSA Decision), the British Columbia Utilities Commission (BCUC) directed FortisBC Energy Inc. (FEI) to file a comprehensive and updated Cost of Service Allocation (COSA) study for each of FEI and the Fort Nelson Service Area (FEFN) for review by the BCUC five years after the release of its final decision in the 2016 Rate Design Application (RDA).[1] The BCUC issued its final Decision and Order G-135-18 (2016 RDA Decision) on July 20, 2018, in which it further directed that, depending on the results of the next COSA study and other considerations, if FEI determined that rate design and/or rebalancing should take place, that FEI would file such proposals together with the COSA study.[2]

Therefore, pursuant to the 2016 COSA Decision and 2016 RDA Decision, FEI is submitting its 2023 COSA study (2023 COSA) and, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), is seeking approval to rebalance the rates for Rate Schedules (RS) 1, 2, 3/23, 4, 5/25, 7/27, and 22 based on the results of the 2023 COSA as proposed in this application (Application).

FEI prepared the 2023 COSA for all of FEI's service areas, including FEFN. Given the BCUC's Decision and Order G-278-22, dated October 6, 2022 (FEFN Common Rates Decision), approving the implementation of common delivery rates and cost of gas rates for FEI and FEFN, and the setting of FEFN's midstream rates at 5 percent of FEI's midstream rates, effective January 1, 2023, a separate COSA for FEFN is no longer required.

Table 1-1 below provides the Revenue-to-Cost (R:C) and Margin-to-Cost (M:C) ratios from the 2023 COSA.

[1] 2016 COSA Decision, page 22 and Directive 5 of Order G-4-18.
[2] 2016 RDA Decision, page 83.

Table 1-1: R:C and M:C Ratio Results before Rebalancing

Rate Schedule	R:C	M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	106.9%	126.9%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%
Rate Schedule 22A Transportation Service (Closed) Inland Service Area	101.8%	101.9%
Rate Schedule 22B Transportation Service (Closed) Columbia Service Area	100.1%	100.1%

Rate Schedule (Not Set Using Allocated Costs)	R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	338.9%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	122.4%	628.0%

As shown in Table 1-1 above, except for RS 5/25 (General Firm Sales and Transportation Service) and RS 22 (Large Volume Transportation Service), the R:C ratios for the applicable rate schedules[3] are within the accepted[4] range of reasonableness between 95 percent and 105 percent. The R:C ratios for RS 5/25 and RS 22 are 106.9 percent and 110.0 percent, respectively, and only a small[5] revenue rebalancing is needed to move both rate schedules back to within the range of reasonableness. The results of the 2023 COSA therefore confirm that FEI's existing rates and rate designs are working well and as intended.

To address the R:C ratios of RS 5/25 and RS 22 being above the upper bound of the range of reasonableness, FEI developed five potential revenue rebalancing options:

[3] Seasonal Firm Service (RS 4) and General Interruptible Sales and Transportation Service (RS 7/27) are not set using their allocated costs from the 2023 COSA, but rather set at a discount to General Firm Service (RS 5/25).

[4] In the 2016 COSA Decision (page 35), the BCUC found that an R:C range of reasonableness of 95 to 105 percent was appropriate and directed FEI to use this R:C range of reasonableness to inform its rate design and rebalancing proposals in the 2016 COSA and RDA Application.

[5] Approximately $3.344 million for RS 5/25 and $151 thousand for RS 22, which is approximately 0.15 percent and 0.007 percent, respectively, of FEI's total revenue at the Approved 2023 rates.

- Option 1: Status Quo;
- Option 2: Revenue Rebalancing Only Using RS 1 (Residential Service) or RS 2 (Small Commercial Service);
- Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 (Large Commercial Sales and Transportation Service), and between RS 3/23 and RS 5/25;
- Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25; and
- Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only.

The five potential revenue rebalancing options listed above were evaluated using the rate design principles identified by Dr. James C. Bonbright, which were the same rate design principles adopted by FEI for its 2016 RDA. As part of the evaluation against the rate design principles, the following issues that would have implications on FEI's customers resulting from each rebalancing option were considered:

- The bill impact of using RS 1 or RS 2 customer groups for rebalancing by absorbing the revenue shift from RS 5/25 and RS 22 customers;
- The impact on the economic crossover point between RS 2 and RS 3/23 customer groups due to any rebalancing; and
- The impact on the economic crossover point between RS 3/23 and RS 5/25 customer groups due to any rebalancing.

Ultimately, Option 5 (Revenue Rebalancing using RS 1 plus adjustments to RS 2 ad RS 3/23 for maintaining the crossover point between RS 2 and RS 3/23) is the preferred option for revenue rebalancing resulting from the 2023 COSA. Option 5 is able to either fully align with or partially align with the most applicable of Bonbright's rate design principles when compared to the other revenue rebalancing options considered by FEI. It can be seen from Table 1-2 below that, under Option 5, the R:C ratios of all applicable rate schedules, including RS 5/25 and RS 22, will fall withing the accepted range of reasonableness of 95 percent to 105 percent.

Table 1-2: Final 2023 COSA Results with Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	4,519	0.4%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	145	0.04%	98.1%	95.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(145)	(0.04%)	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Option 5 is also able to preserve the economic crossover point between RS 2 and RS 3/23 customers while minimizing the bill impacts to both residential and commercial customers. As shown in Table 1-3 below, the bill impact to residential customers under Option 5 is relatively small at 0.4 percent (i.e., equivalent to approximately $4.95 per year for an average residential customer with 90 GJ of consumption annually) while the bill impact to commercial customers is the smallest out of all options (i.e., 0.04 percent or $1.65 per year for an average RS 2 customer consuming 322 GJ annually and a credit of 0.04 percent or $9.74 per year for an average RS 3/23 customer consuming 3,650 GJ annually).

Table 1-3: Summary of Bill Impact (%) to each Rate Schedule for all Rebalancing Options[6]

	Average Bill Impact (%)					
	Option 1: Status Quo	Option 2a: Revenue Rebalancing Only Using RS 1	Option 2b: Revenue Rebalancing Only Using RS 2	Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25	Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25	Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only
RS 1	-	0.4%	-	0.4%	-	0.4%
RS 2	-	-	1.2%	1.1%	1.1%	0.04%
RS 3/23	-	-	-	(1.2%)	0.1%	(0.04%)
RS 5/25	-	(1.8%)	(1.8%)	(1.8%)	(1.8%)	(1.8%)
RS 6	-	-	-	-	-	-
RS 22	-	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)
RS 22A	-	-	-	-	-	-
RS 22B	-	-	-	-	-	-
RS 4	-	(3.0%)	(3.0%)	(3.0%)	(3.0%)	(3.0%)
RS 7/27	-	(1.1%)	(1.1%)	(1.1%)	(1.1%)	(1.1%)

In Order G-372-22,[7] FEI was directed to provide an analysis of the costs and revenue associated with its Transportation Service Model as part of its next COSA study. Based on FEI's analysis, the average of actual balancing charges recovered from 2018 to 2022 was approximately 0.08 percent of FEI's total allocated cost of service included in the 2023 COSA. As such, the Transportation Service Model has no material impact on FEI's 2023 COSA and does not result in any changes to the R:C ratio of any rate schedule.

[6] Seasonal (RS 4) and General Interruptible Service (RS 7/27) rates are set at a discount to RS 5/25 rates. As such, any rebalancing to RS 5/25 would result in changes to the rates and revenues of RS 4 and RS 7/27 in order to maintain their current discount to RS 5/25.

[7] Directive 2.

2. APPROVALS SOUGHT, PROPOSED REGULATORY PROCESS AND ORGANIZATION OF THE APPLICATION

2.1 *APPROVALS SOUGHT*

In this Application, FEI is seeking approval pursuant to sections 58 to 61 of the UCA to implement the following rate changes, effective January 1, 2025, as a result of revenue rebalancing:

Residential Rate Schedules (RS 1, 1U, and 1B):

1. Approval to increase the Delivery Charge by $0.055 per GJ as a result of the revenue shifts and rebalancing of rates discussed in Section 5.2.1 of the Application.

Commercial Rate Schedules (RS 2, 2U, 2B, 3, 3U, 3B, and 23):

2. For Rate Schedules 2, 2U, and 2B:
   - Approval to adjust the basic charges and delivery charges to align with the 2,000 GJ threshold between small and large commercial customers discussed in Section 5.2.3 of the Application, as follows:
     i. Increase the Basic Charge by $0.2026 per day from $0.9485 to $1.1511 per day; and
     ii. Decrease the Delivery Charge by $0.225 per GJ.
3. For Rate Schedules 3, 3U, 3B, and 23:
   - Approval to adjust the basic charges and delivery charges to align with the 2,000 GJ threshold between small and large commercial customers discussed in Section 5.2.3 of the Application, as follows:
     i. Increase the Basic Charge by $0.4730 per day from $4.7895 to $5.2625 per day; and
     ii. Decrease the Delivery Charge by $0.050 per GJ.

Industrial Rate Schedules (RS 4, 5/25, 22, and 7/27):

4. For Rate Schedule 4:
   - Approval to decrease the Off-Peak Delivery Charge by $0.309 per GJ and the Extension Period Delivery Charge by $0.069 per GJ due to the proposed changes to RS 5/25 for maintaining the current discount from general firm service customers as discussed in Section 5.2.2.
5. For Rate Schedules 5, 5B, and 25:
   - Approval to adjust the Demand Charge and Delivery Charge as a result of the revenue shifts and rebalancing of rates discussed in Section 5.2.1 of the Application, as follows:
     i. Decrease Demand Charge by $1.989 per GJ per month, and

   ii. Decrease Delivery Charge by $0.071 per GJ.

6. For Rate Schedules 7 and 27:
   - Approval to decrease the Delivery Charge by $0.095 per GJ due to the proposed changes to RS 5 and RS 25 for maintaining the current discount from general firm service customers as discussed in Section 5.2.2.
7. For Rate Schedule 22:
   - Approval to adjust the rates of RS 22 for all large industrial customers as a result of the revenue shifts and rebalancing discussed in Section 5.2.1 of the Application, as follows:
      i. Decrease the Firm Demand Charge by $0.505 per GJ per month;
      ii. Decrease the Firm Monthly Transportation Quantity (MTQ) Delivery Charge by $0.009 per GJ; and
      iii. Decrease the Interruptible MTQ Delivery Charge by $0.026 per GJ.

In Section 2.2 below, FEI has proposed a regulatory review process for the Application which contemplates a decision some time in 2024. To minimize customer confusion potentially caused by changes in rates mid-year, it is preferable and more practical to implement any changes due to this Application together with FEI's general delivery rate changes, which are typically approved effective on January 1st of each year following either an Annual Review process or as part of a revenue requirement application. Therefore, based on the anticipated timing of a decision, FEI is requesting that the approvals sought in this Application be implemented effective January 1, 2025.

A Draft Order setting out the approvals sought is provided in Appendix A of the Application.

2.2 *PROPOSED REGULATORY PROCESS*

FEI proposes a written public hearing process with one round of information requests (IRs) as an appropriate and efficient review process for this Application. The Application follows FEI's 2016 RDA which was a comprehensive rate design application and underwent a significant regulatory review process. Given that FEI is not proposing any changes to its currently approved rate designs and that the proposed rate rebalancing results in minimal impacts to customers, FEI believes that one round of IRs will be sufficient. Therefore, FEI proposes the following regulatory timetable for the review of the Application. A draft procedural Order is provided in Appendix A.

Table 2-1: Proposed Regulatory Timetable

Action	Date (2023)
BCUC Issues Procedural Order by	Thursday, August 17
FEI provides Notice by	Friday, August 25
Intervener Registration Deadline	Thursday, September 14
BCUC & Intervener IR No. 1	Thursday, October 5

Action	Date (2023)
FEI Response to IR No. 1	Thursday, November 23
FEI Written Final Argument	Thursday, December 14
Action	**Date (2024)**
Intervener Written Final Arguments	Thursday, January 18
FEI Written Reply Argument	Thursday, February 8

2.3 *ORGANIZATION OF THE APPLICATION*

The remainder of the Application is organized into the following sections:

- Section 3 provides the history of FEI's rate design and the BCUC's decisions on previous rate design applications (RDAs) and COSA studies;
- Section 4 provides an overview of FEI's COSA methodology and cost allocation process, as well as the R:C and M:C ratios and results;
- Section 5 describes the revenue and rate rebalancing options and FEI's proposed revenue rebalancing;
- Section 6 discusses the costs and revenues of the Transportation Service Model in relation to the 2023 COSA; and
- Section 7 concludes the Application.

3. FEI'S COSA AND RATE DESIGN HISTORY

3.1 *INTRODUCTION*

A COSA study is a fundamental component of the design of a utility's rates. A COSA study provides important contextual information in assessing how the current/proposed rates and rate structures perform against the relevant rate design principles, as well as other considerations, such as the effectiveness of the utility's rates to recover the cost of service, the fairness of cost apportionment among each customer class, and the potential of any undue discrimination or revenue instability due to the current/proposed rate design.

FEI's current rate design and structure were developed through a number of rate design proceedings over the years, most notably, the two-phased RDA process in 1991 and 1993, the 1996 RDA, the 2001 RDA, the 2012 Common Rates, Amalgamation and RDA, and the 2016 RDA. Each of these rate design proceedings included a COSA study, either on a regional basis or a consolidated/amalgamated basis.

3.2 *1991 PHASE A AND 1993 PHASE B RATE DESIGN APPLICATION*

In October 1991, FEI (then BC Gas) filed the 1991 Phase A RDA which primarily considered the gas supply cost allocation methodology for the Lower Mainland and Inland service areas. By Order G-22-92, the BCUC approved for FEI the methodology to allocate commodity-related costs within the gas supply portfolio on an energy-related basis, while classifying fixed costs associated with storge and transport[8] as demand-related costs and allocating those costs to customer classes based on a coincident peak day demand methodology. The BCUC also approved FEI's proposed regional gas cost allocation and gas cost rates for the Lower Mainland and Inland divisions, managed under a single portfolio. The Columbia division was subsequently brought into the common gas supply portfolio and gas cost allocation with the Lower Mainland and Inland divisions once the existing long term gas supply contracts at that time expired.

In April 1993, FEI filed the 1993 Phase B RDA which considered the allocation of all other utility costs, except for the gas supply costs. The application also sought approval for the consolidation of the Lower Mainland, Inland, and Columbia divisions and related postage-stamping of delivery rates for residential, commercial, and general firm service customer classes (with regional gas cost allocation remaining in place). The application was supported by a COSA study which used the industry accepted minimum system costs study and customer weightings to classify distribution costs into demand and customer related components, and to allocate customer related costs. FEI also proposed the range of reasonableness for the Revenue-to-Cost (R:C) ratio of each customer rate schedule to be in the range of 90 percent to 110 percent.

By Order G-68-93, dated August 13, 1993, the BCUC approved the consolidation of the Lower Mainland, Inland, and Columbia divisions for regulatory purposes, including the adoption of

8 The fixed cost component of any commodity supply net of contacts in place.

common accounting practices. Subsequently by its Decision and Order G-101-93, dated October 25, 1993, regarding the Phase B RDA (Phase B Decision), the BCUC approved postage-stamp delivery rates for the Lower Mainland and Inland service areas.[9] Although the BCUC did not approve the inclusion of the Columbia division to the postage-stamp delivery rates for the Lower Mainland and Inland divisions, the BCUC did approve FEI to set the same rates for Columbia as the postage-stamp delivery rates for the Lower Mainland and Inland divisions.[10] Since that time, the Columbia service area has had the same delivery rates and rate structures as the Lower Mainland and Inland service areas.

In the Phase B Decision,[11] the BCUC also approved the adoption of a consolidated set of General Terms and Conditions to be applied across the service areas (other than Fort Nelson)[12] and approved FEI to price interruptible service at a discount to firm service, based on the value of the service.

3.3 *1996 AND 2001 RATE DESIGN APPLICATION*

The 1996 RDA and 2001 RDA were two significant rate design proceedings since the two-phase proceeding in 1991 and 1993. Both the 1996 and 2001 RDA were built on the COSA methodologies established in the 1991 and 1993 proceeding with minor changes. The BCUC Orders from these proceedings (i.e., Orders G-98-96 and G-116-01) re-affirmed the fundamental methodologies outlined in the 1991 and 1993 proceedings.

In the 1996 proceeding, the BCUC approved the continued use of a 90 percent to 110 percent range of reasonableness of the R:C ratio for rate setting amongst customer classes. A Negotiated Settlement Process (NSP) was undertaken for the proceeding and the resulting Negotiated Settlement Agreement (NSA) was approved by Order G-98-96.[13]

In August 2000, the BCUC directed FEI to file another RDA,[14] which was filed on February 5, 2001. The focus of the 2001 RDA was the allocation of costs associated with newly completed capital projects prior to 2001. At the request of participants of a workshop and prehearing conference, the BCUC retained an independent rate design consultant, EES Consulting, to review the 2001 COSA study, which was included as part of the 2001 Rate Design Application. EES Consulting validated FEI's COSA study and confirmed that the methodology corresponded to generally accepted rate setting practices. The 2001 RDA was subjected to an NSP and the

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9 Page 10.

10 Section 3.3 of Decision and Order G-101-93, dated October 25, 1993 approved the rate design basis at that time and Section 4.4 of the Decision approved the rate design of residential and commercial rates, including the Columbia service area, which resulted in the same rates as the Lower Mainland and Inland service areas. See also the BC Gas Tariff dated January 1, 1994, page R-1.1

11 Page 49.

12 Postage stamping for the Fort Nelson division was not proposed in the 1993 Phase B Rate Design Application.

13 Dated October 7, 1996.

14 Order G-75-00, dated August 4, 2000.

resulting settlement document was approved by Order G-116-01.[15] The approved settlement document included minor changes to the rate schedules at that time.

3.4 *2012 COMMON RATES, AMALGAMATION AND RATE DESIGN APPLICATION (2012 RDA) AND 2013 RECONSIDERATION OF 2012 RDA*

In 2012, the FortisBC Energy Utilities, comprised of FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC Energy (Whistler) Inc. (FEW), filed the 2012 Common Rates, Amalgamation, and Rate Design Application to the BCUC for approval to amalgamate FEI, FEVI, and FEW, and to implement common or postage-stamp rates throughout the amalgamated utility's combined service areas. The application was supported with a COSA study that combined each of the utilities into an amalgamated entity with postage-stamp delivery, midstream, and commodity charges.

After an initial decision and reconsideration process, on February 26, 2014, the BCUC issued its Decision and Order G-21-14 (Common Rates Decision), determining that amalgamation was beneficial and in the public interest and that it would provide economic and other benefits to FEI customers. The BCUC also determined that, in the context of FEI as an amalgamated entity, rate stability for the larger group of customers would be increased with the implementation of common rates. The amalgamation was consented to by the Lieutenant Governor in Council Order in Council (OIC) No. 300, dated May 23, 2014, and came into effect December 31, 2014. Common rates were implemented for the amalgamated FEI entity on January 1, 2015. The Common Rates Decision also directed FEI to file a comprehensive RDA for the amalgamated entity no later than two years after the effective date of the amalgamation.[16]

3.5 *2016 RATE DESIGN APPLICATION*

In December 2016, in compliance with the Common Rates Decision, FEI filed the 2016 RDA which proposed changes intended to realign the rate design with accepted rate design principles and rebalance rates based on the updated 2016 COSA studies.

On February 21, 2017, the BCUC issued a letter[17] explaining that the BCUC staff retained an independent consultant, Elenchus Research Associates Inc. (Elenchus) to independently review FEI's COSA study and rate design. Elenchus filed its COSA report on April 26, 2017,[18] and its Rate Design Report on June 23, 2017.[19]

On January 9, 2018, following a Streamlined Review Process (SRP) on the 2016 COSA and R:C ratios, the BCUC issued the 2016 COSA Decision, finding that FEI's COSA methodology

[15] Dated November 7, 2001.
[16] Order G-21-14, Directive 5.
[17] Exhibit A-4 of the 2016 RDA Proceeding.
[18] Exhibit A2-2 of the 2016 RDA Proceeding.
[19] Exhibit A2-10 of the 2016 RDA Proceeding.

generally follows standard practice, which both EES Consulting (FEI's expert consultant for the 2016 RDA) and Elenchus (the BCUC's independent expert) viewed as being reasonable and acceptable for setting just and reasonable rates.[20] The BCUC also determined that the R:C ratios should be used to inform rate design and rate rebalancing proposals,[21] and directed FEI to use an R:C ratio range of reasonableness of 95 percent to 105 percent[22] to inform rate design and rebalancing proposals.[23] FEI was directed to file updates to the 2016 RDA in response to the findings and directives in the COSA Decision.

On February 6, 2018, FEI filed an updated application in response to the findings and directives in the 2016 COSA Decision, primarily for rate rebalancing based on the new R:C ratio range of reasonableness of 95 percent to 105 percent. On July 20, 2018, the BCUC issued the 2016 RDA Decision approving, among other things:

- The continuation of the current flat rate structure for residential customers (RS 1). The BCUC also found that the overall annual bill impact of FEI's residential rate design proposals, between +/- 1 percent for the majority of residential customers, to be acceptable and that the impact is a reasonable balance of cost causation with rate and revenue stability considerations;
- The continuation of the existing flat rate structure for commercial customers (RS 2, 3, and 23), with minor adjustment to the customer segmentation threshold to 2,000 GJ between RS 2 and RS 3/23 customers;
- An adjustment to the multiplier in the Daily Demand formula in RS 5/25 general firm service from 1.25 to 1.10 and an increase to the Demand Charge of RS 5/25 such that the economic crossover point between RS 3/23 and RS 5/25 incented high load factor customers to take service under RS 5/25, which also generated revenues needed to recover the cost of service;
- The continuation of the existing discount between interruptible (RS 7/27) and firm service (RS 5/25), and also between seasonal firm service (RS 4) and firm service (RS 5/25);
- A new cost-based firm service under RS 22 with rates similar to current contract rates under RS 22, and the continuation of the closed and grandfathered status of RS 22A and RS 22B service;
- The rebalancing of RS 5/25 and RS 6/6P to within the range of reasonableness of 95 percent to 105 percent by shifting revenues to FEI's residential customers (RS 1). The BCUC noted RS 1 is the only rate class with an R:C ratio below 100 percent and residential customers have the capacity to absorb these amounts with the lowest bill impact to individual customers. The BCUC also determined FEI's proposal not to rebalance RS 22A

[20] COSA Decision, page 11.
[21] COSA Decision, page 25. This was consistent with past COSA and RDA decisions.
[22] This represented a change from the previously used R:C range of 90 percent to 110 percent from the prior COSA and RDA decisions.
[23] COSA Decision, page 35.

was reasonable and not unduly discriminatory even though the RS 22A R:C ratio was outside the range of reasonableness (i.e., above 105 percent) because the existing rates of the closed RS 22A is already more favourable than other large industrial customers;

- The BCUC also determined there was insufficient support for FEI to rebalance to unity based on the evidence provided by Elenchus,[24] as follows:
  - Any R:C ratio that is within the defined range of reasonableness can be considered to be full cost recovery;
  - Rebalancing should be undertaken to move classes that are outside the approved range to the nearest boundary;
  - It is not appropriate to periodically rebalance to R:C ratios of 1.00; and
  - Elenchus is not aware of any jurisdiction that periodically rebalances rates so that all R:C ratios are 1.00; and
- The implementation of daily balancing for all transportation services customers, amendments to reduce the daily balancing tolerance to a 10 percent threshold and the introduction of an additional daily balancing charge for gas supply shortfalls within a 10 to 20 percent tolerance level for RS 22, 22A, 23, 25, 26, and 27.

In addition, the 2016 RDA Decision[25] also reiterated the directive[26] in the 2016 COSA Decision,[27] for FEI to file a comprehensive and updated COSA study for each of FEI and FEFN for review by the BCUC five years after the release of the 2016 RDA Decision (by July 20, 2023). This Application is made pursuant to that directive.

3.6 *COMMON RATES APPLICATION FOR THE FORT NELSON SERVICE AREA*

On August 12, 2021, FEI filed an application with the BCUC to, among other things, implement common delivery and cost of gas rates for FEFN with the rest of FEI's service territories, and to set FEFN's midstream rates at 5 percent of FEI's midstream rates, effective January 1, 2023. On October 6, 2022, the BCUC issued the FEFN Common Rates Decision approving FEI's application and directing FEI to phase in the bill impact for FEFN residential customers over a 5-year period.

As part of the FEFN Common Rates Decision, the BCUC also approved, effective January 1, 2023, the following:

- The amalgamation of FEFN's gas cost portfolios with FEI, thus eliminating FEFN's Gas Cost Reconciliation Account (GCRA), such that all of FEFN's natural gas supply portfolio

[24] 2016 RDA Decision, page 42.
[25] 2016 RDA Decision, page 83.
[26] COSA Decision, Directive 5.
[27] COSA Decision, page 22.

costs, including transportation costs, are captured in FEI's Midstream Cost Reconciliation Account (MCRA);[28]

- The transfer or consolidation of the December 31, 2022 closing balances of FEFN's deferral accounts to FEI;[29]
- The transfer of the closing December 31, 2022 balance of FEFN's gross plant-in-service, accumulated depreciation, CIAC, accumulated amortization of CIAC, capital work-in-progress (no AFUDC), and unamortized deferred charges to the corresponding accounts in FEI's rate base as January 1, 2023 opening balance adjustments;[30]
- The inclusion of FEFN's operating and maintenance (O&M) expenses in FEI's formula O&M;[31] and
- The incorporation of FEFN's annual forecast capital expenditures into FEI's regular forecast capital expenditures.[32]

The BCUC also determined that it is inappropriate and would create unnecessary administrative burden on FEI and all of its customers, including FEFN customers, to track costs associated with providing service to FEFN customer separately.[33] As such, with the implementation common rates for FEFN, FEI no longer maintains a separate rate base for FEFN and does not set FEFN's O&M separately from FEI's formula O&M. As a result, the costs and revenues of FEFN are not reflected separately in the 2023 COSA but rather FEFN is included in the 2023 COSA in the same way as all of FEI's other service areas.

[28] FN Common Rates Decision, page 33.
[29] FN Common Rates Decision, page 35.
[30] FN Common Rates Decision, page 41.
[31] FN Common Rates Decision, page 41.
[32] FN Common Rates Decision, page 42.
[33] FN Common Rates Decision, page 42.

4. FEI'S COSA METHODOLOGY

A COSA study is used by a utility to determine how to allocate and recover costs through customer rates between different rate classes. Except for the minor changes discussed in this section, FEI's 2023 COSA is based on the same methodology as FEI's 2016 COSA study.

In the 2016 COSA Decision, the BCUC found that the 2016 COSA study generally followed standard practice, and both EES Consulting and Elenchus viewed its as being reasonable and acceptable for setting just and reasonable rates.[34] Specifically, in its COSA Report, Elenchus stated that the classifications of demand, energy, and customer are the standard classifications used in COSA studies and that they agreed with the classifications used by FEI. Additionally, Elenchus was not aware of any other classification method used in COSA studies.[35] Elenchus also agreed with the allocators as well as the gas cost allocation methodology used by FEI in the 2016 COSA study, stating that they are the standard allocators used by utilities in COSA studies.[36]

The 2023 COSA reflects the costs and revenues approved by the BCUC for FEI's 2023 test year as part of FEI's Annual Review for 2023 Delivery Rates,[37] plus any known and measurable changes expected by or soon after January 1, 2025, which is the effective date that FEI is seeking approval to implement the changes proposed in this Application. The allocated costs are compared to the revenue collected, by rate schedule, to calculate the R:C ratio of each rate schedule, which indicates whether the rates in each rate schedule adequately recover the allocated cost of each rate schedule. As determined in the 2016 COSA Decision and discussed in Section 3.5, FEI used a range of reasonableness of 95 percent to 105 percent to evaluate the R:C ratio for each rate schedule, with the exception of RS 22A/B, 4, and 7/27. FEI did not hold RS 22A/B to the range of reasonableness, as the BCUC approved these rate schedules to remain closed and to continue their grandfathered status.[38] Consistent with the 2016 COSA study, FEI also did not hold RS 4 and RS 7/27 to the range of reasonableness since RS 4 is for seasonal service (with interruptible status in the winter months) and RS 7/27 are fully interruptible services.

The following sections provide an overview of FEI's current COSA methodology, including a discussion of changes since the 2016 COSA study.

4.1 *OVERVIEW OF FEI'S COST ALLOCATION*

Figure 4-1 below provides an overview of how FEI's costs, including delivery and gas costs, are allocated to specific customer groups through the COSA Model.

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34 2016 COSA Decision, p. 11.

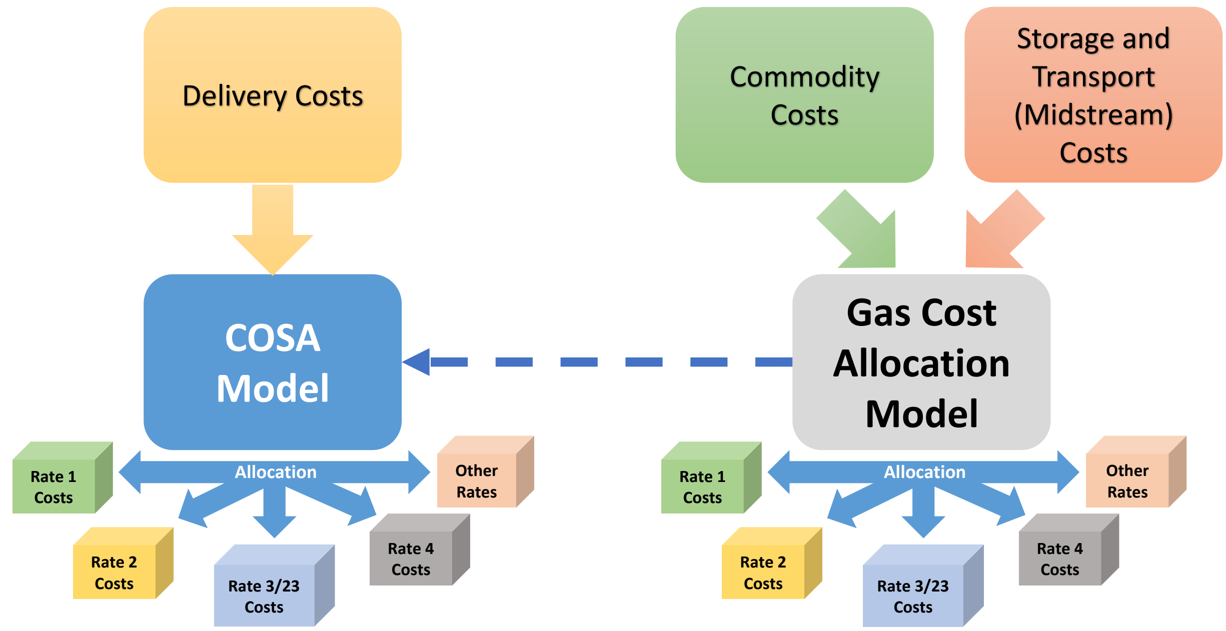
35 Exhibit A2-2 of 2016 RDA proceeding, Elenchus COSA Report, page 15.

36 Exhibit A2-2 of 2016 RDA proceeding, Elenchus COSA Report, pages 17-19.

37 Decision and Order G-352-22, dated December 6, 2022.

38 RS 22B was within the range of reasonableness between 95 percent and 105 percent; however, it has the same closed and grandfathered status as RS 22A, which was outside of the range of reasonableness.

Figure 4-1: FEI Cost Allocation Overview



FEI's gas costs, including both commodity and storage and transport (midstream) costs, are reviewed on a quarterly basis using a different model than FEI's delivery costs, which are reviewed on an annual basis. As such, FEI's revenue requirement in this Application is split into two categories: delivery costs and gas costs. FEI's delivery costs are defined as FEI's revenue requirement excluding gas costs[39] and are allocated in a delivery margin COSA model. Gas costs are then added to the allocated delivery margin to calculate the R:C ratios.[40]

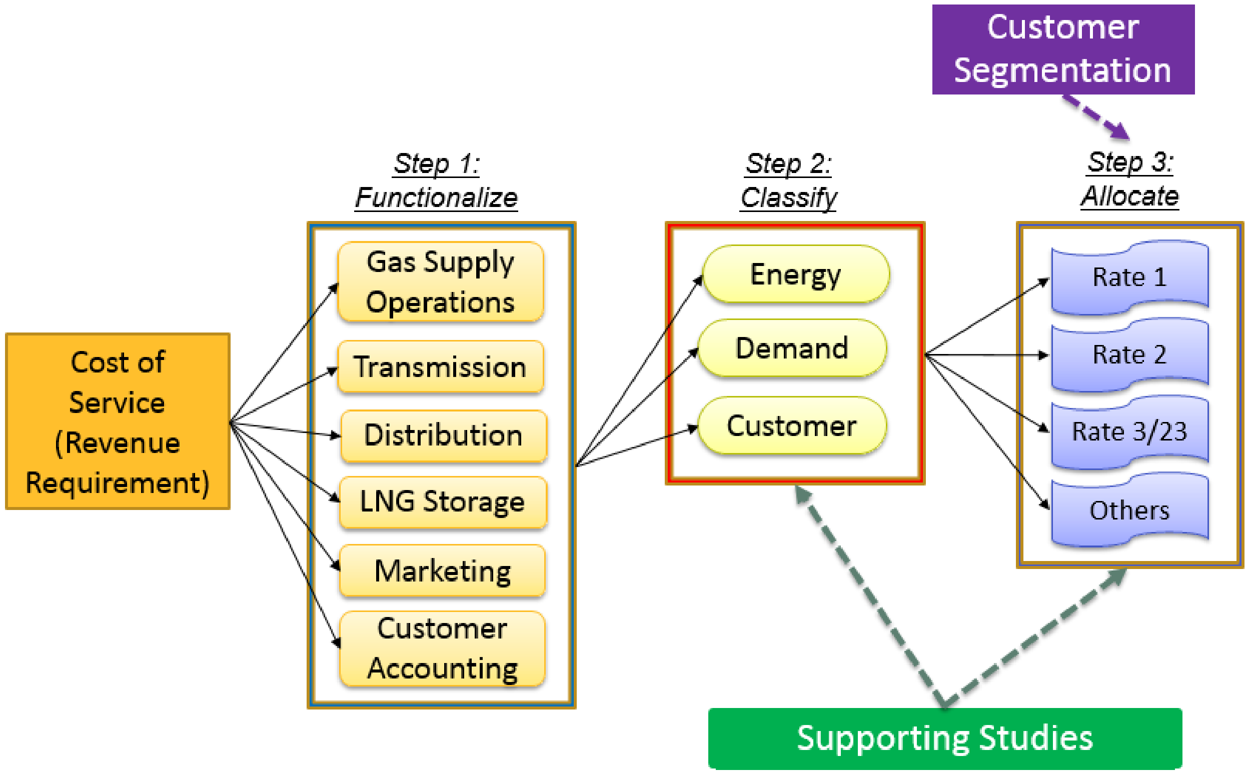
4.1.1 The Three Steps of Cost Allocation

The COSA study follows three standard steps to allocate the cost of service. The steps are functionalization, classification, and allocation. The result, as shown in Figure 4-2 below, is the allocation of FEI's cost of service to each customer rate schedule. Each of the three steps is discussed in the subsections below.

[39] The delivery margin equals the revenue minus the gas costs.

[40] Gas costs are not allocated in the delivery margin COSA model; they are included as cost inputs to FEI's COSA model based on pre-approved rates for the purpose of determining the R:C ratios.

Figure 4-2: FEI Cost of Service Allocation Steps



4.1.1.1 Functionalization

The first step in the COSA study is the functionalization of costs. The functionalization step involves separating the costs from the test year revenue requirement into the major categories that reflect the utility's plant investment code of accounts and different services provided to customers. After assigning plant costs functionally, related expenses are functionalized along the same basis. For FEI, the 2023 COSA contains the following functions: Gas Supply Operations, Transmission, Distribution, Liquefied Natural Gas (LNG) Storage, Marketing, and Customer Accounting. Costs that are directly related to the defined function are assigned to those functions. General costs and intangible plant costs are typically functionalized across all functions according to the relative functional portions of gross plant in service.

4.1.1.2 Classification

The second step in the COSA study is to classify the functionalized costs into cost-causation categories. These categories are related to the reasons why FEI incurs the costs (i.e., the drivers of the costs). The costs are generally incurred based on three drivers: peak day demand, energy delivered, or the existence of a customer on the system. Each classification uses cost allocators that will distribute those costs among the appropriate customer rate schedules. The three classifiers are discussed further below.

- **Demand:** Demand-related costs are those associated with plant that is designed, installed and operated to meet maximum daily gas flow requirements, such as transmission and distribution mains. Essentially, these are all costs associated with having peak capacity on standby and available upon peak customer demand. Given this, transmission and distribution capacity, compressor costs, and LNG storage are classified as demand-related costs with respect to FEI's requirement for serving peak demand at the winter peak.

- **Energy:** Energy-related costs are those costs that vary with the volume of gas delivered to customers. In the case of FEI, other than the commodity supply purchased on behalf of FEI's customers, few of the costs to operate FEI's facilities are variable with respect to the volume of gas delivered to customers. Commodity supply expenses are classified as energy-related costs as a means to apportion the costs to sales customers.

- **Customer:** Customer-related costs are those that are incurred as a result of having a customer attached to the distribution system, metering the customer's gas usage and maintaining the customer's account. These costs may include capital costs associated with the investment in minimum size distribution mains, services, meters, house regulators, as well as marketing and customer accounting related activities. The costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas.

Not all costs can be wholly classified into one of these three classifications. For example, the costs of distribution mains are considered to be caused by multiple factors such as the number of customers connecting to the system (i.e., customer classification) and by the maximum daily gas flow requirement (i.e., demand classification). As such, the causation of these costs will be a combination of the demand and customer classifications, and additional supporting studies are required to determine the appropriate apportionment between the two classifications. FEI conducted a Minimum System Study (MSS) with Peak Load Carrying Capability (PLCC) adjustment, as further discussed in Section 4.3.2.4 of this Application, to aid the classification of distribution costs into both customer and demand related costs.

4.1.1.3 Allocation

The third step in the COSA process is to allocate the classified costs to FEI's rate schedules. This allocation of costs is based on the contribution of each rate schedule to the specific classifier selected, as determined by analysis of factors such as customer requirements, loads, usage characteristics, system design and operations, accounting, and physical asset records. For example, costs that are classified as customer-related are allocated across all rate schedules on the basis of the number of customers in each rate schedule. Further discussion on the allocation of delivery costs and gas costs is provided in Sections 4.3.3 and 4.4, respectively.

4.1.2 Results of Cost Allocation: Revenue-to-Cost (R:C) and Margin-to-Cost (M:C) Ratios

The result of the three-step cost allocation is to derive the R:C ratios by dividing the revenue from each rate schedule by the allocated costs as well as the M:C ratios by dividing the delivery costs (or delivery margin) from each rate schedule by the allocated delivery-related costs. The resulting R:C and M:C ratios help inform whether there is a need for revenue rebalancing. Revenue rebalancing is the method by which the utility shifts revenue responsibility from one customer group to another. As previously discussed, FEI is utilizing a range of reasonableness from 95 percent to 105 percent to evaluate the need or level of revenue rebalancing, if required, consistent with the approved approach in the 2016 COSA and RDA proceeding.

4.2 *FEI REVENUE REQUIREMENT FOR 2023 COSA*

In this section, FEI presents the revenue requirement and rate base that will be used as part of the 2023 COSA. These are the costs that will be functionalized, classified, and allocated through the three-step COSA as shown in Figure 4-2 above. The following sections also discuss the assumptions to the 2023 COSA as well as any known and measurable changes to FEI's revenue requirement and rate base that were used in the 2023 COSA.

4.2.1 Basis of Revenue Requirement and Rate Base – Test Year

For the 2023 COSA model, FEI used the 2023 approved costs from its Annual Review for 2023 Delivery Rates proceeding[41] as the test year for the basis of cost allocation. FEI chose the 2023 approved costs because they reflect the most current operating conditions, include both FEI and FEFN under common delivery rates as discussed in Section 3.6, and were the most recently available approved costs at the time the 2023 COSA was prepared.

Tables 4-1 and 4-2 summarize FEI's 2023 approved revenue requirement of $2,249 million and rate base of $5,943 million, respectively, which are used to form the basis of the 2023 COSA model. The approved financial schedules for FEI's 2023 revenue requirement and cost of service are provided in Appendix B.

[41] The 2023 delivery rates were approved on an interim basis pursuant to Order G-352-22, pending the outcomes of Stage 1 of the BCUC's Generic Cost of Capital (GCOC) proceeding (not yet issued) and FEI's Application for Acceptance of Demand Side Management (DSM) Expenditures Plan for 2023 proceeding (Decision and Order G-45-23, dated March 6, 2023).

Table 4-1: Summary of FEI's 2023 Test Year Revenue Requirements ($ millions)

Revene Requirement Components		
Cost of Gas		1,171
O&M Expense (Net)		292
Depreciation		221
Amortization		106
Property Taxes		79
Other Revenue		(42)
Income Tax		52
Earned Return		370
Total	**$**	**2,249**

Table 4-2: Summary of FEI's 2023 Test Year Rate Base ($ millions)

Rate Base Components (mid-year)		
Gross Plant-in-Service		8,528
Accumulated Depreciation		(2,655)
Contribution in Aid of Construction (CIAC)		(462)
Accumulated Amortization (CIAC)		201
Adjustment for Timing of Capital Additions		122
Unamortized Deferred Charges		53
Capital Work in Progress		43
Working Capital		113
Total	**$**	**5,943**

4.2.2 Key Assumptions for Test Year Revenues and Costs

The following sections summarize five key assumptions in the 2023 COSA model when using the 2023 approved revenue requirement and rate base as the basis of allocation.

4.2.2.1 Developing an Activity View of O&M Expenses

FEI is currently setting rates under the approved[42] Multi-year Rate Plan (MRP) framework which is in place from 2020 to 2024. As such, the 2023 gross O&M is predominantly determined based on formula (approximately 84 percent of 2023 gross O&M) with the remaining 16 percent determined on a forecast basis. Since the majority of FEI's gross O&M is determined using a formula and not developed on an activity view (O&M at the activity view is only accounted for in actuals), FEI has split its 2023 gross O&M into an activity view using percentages derived from its 2022 actual activity view O&M so that it could be used for the purpose of allocating O&M expenses in the COSA model. This approach is consistent with the 2016 COSA study, in which FEI's O&M was also determined based on a formula under the 2014-2019 Performance Based

[42] 2020-2024 MRP Decision and Order G-165-20, dated June 22, 2020 (2020-2024 MRP Decision).

Ratemaking (PBR) Plan at that time.[43] Appendix C sets out the allocation percentages that were applied to FEI's 2023 approved gross O&M to derive an activity view for allocation in the 2023 COSA model.

4.2.2.2 Treatment of Bypass and Large Industrial Contract Customer Revenue

FEI's 2023 forecast revenue includes 10 bypass contract customers and one large industrial contract customer. Consistent with FEI's approach in past COSA studies, including the 2016 COSA study, the revenues of bypass and large industrial contract customers are treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules (i.e., sales and non-contract transportation service).

Bypass contracts are service agreements included in FEI's tariff supplements related to its rate schedules. Bypass industrial customers are in close proximity to upstream transmission pipelines and these customers have negotiated with FEI for delivery rates that are based on the customer's estimated cost of constructing and operating its own hypothetical pipeline to bypass FEI's system. Except for the specific rate (and rate-related terms and conditions), the terms and conditions of service in bypass contracts generally conform to the standard rate schedule under which the customer would otherwise receive service. All bypass rates are contractual obligations, the rates cannot be changed outside the terms of the contract, and the bypass agreements are approved by the BCUC.[44] Additionally, all bypass contracts have provisions for O&M and property tax escalations or recovery of actual costs. This Application contemplates no change to the rates, or terms and conditions applicable to bypass customers, which are set through their tariff supplements.

Table 4-3 below provides additional information for FEI's current bypass contracts.

Table 4-3: Summary of FEI's Bypass Customers[45]

	RS 22	RS 22A	RS 25	Other	Total
No. of Customers	2	4	3	1	10
2023 Forecast Volume (TJ)	11,946		951	12	12,909
2023 Forecast Revenue ($000s)	799		424	134	1,357

Large industrial contract customers (referred to as contract customers) are those customers that have historically negotiated their rates with FEI. Contract customers' rates are fixed in their

43 Decision and Order G-138-14, dated September 15, 2014.

44 FEI's General Terms and Conditions (GT&C) refers to bypass contracts as "exceptional circumstances" where factors such as system by-pass opportunities exist. Factor inputs taken into consideration for negotiating the bypass agreements are: gas volume, capital cost, operating and maintenance costs, property taxes, income tax impacts, customers' capital structure and cost of capital, and upstream pipeline connection charges. See also the BCUC Commissioner Vern Millard Report and Recommendations to the Lieutenant Governor in Council (LGIC) in the Matter of Applications for Energy Project Certificates, dated October 22, 1987, undertaken pursuant to OIC No. 552, approved and ordered March 19, 1987.

45 FEI has included Teck Coal (Byron Creek) as a bypass customer in its revenue requirements. The contract is a Pipeline Agreement which specifies how the 'Actual Annual Service Charge' is determined. The annual service charge is not affected by BCUC approved rate changes. As such, it is similar to FEI's bypass contracts.

respective transportation service agreements. FEI currently only has one large industrial contract customer, the Vancouver Island Gas Joint Venture (VIGJV or Joint Venture). As approved by Order G-13-23, dated January 24, 2023, the Transportation Service Agreement (TSA) between the VIGJV and FEI is extended for five years, effective from November 1, 2022 to November 1, 2027. FEI previously had one other large industrial contract customer, BC Hydro Island Generation (IG); however, its contract with FEI expired in April 2022. BC Hydro IG is now taking service as a fully interruptible RS 22 large volume transportation service customer and therefore, is included in FEI's 2023 forecasts (as well as in the 2023 COSA) as a RS 22 customer.

4.2.2.3 Treatment of Biomethane Customer Costs

FEI's biomethane service offering allows customers to elect to receive a portion of their natural gas as renewable natural gas. Renewable natural gas is a renewable and carbon neutral energy source that reduces greenhouse gas (GHG) emissions when used in place of conventional natural gas. The current underlying cost recovery mechanisms for FEI's biomethane service were approved by Order G-133-16,[46] and, pursuant to the 2020-2024 MRP Decision for FEI,[47] all biomethane related costs and revenues, including the original seven interconnections that were previously accounted for in FEI's delivery margin revenue requirement, are now included in the Biomethane Variance Account (BVA) with the balance to be recovered from customers through the Biomethane Energy Recovery Charge (BERC) and the BVA Rate Rider. As such, there are no biomethane costs and revenues accounted for in the 2023 COSA (i.e., all biomethane related assets or costs as well as any offsetting revenues such as the BVA Rate Rider are removed from FEI's rate base or cost of service for allocation purposes).

4.2.2.4 Treatment of Natural Gas for Transportation Customer Revenues/Costs

FEI's Natural Gas for Transportation (NGT) program provides incentives to customers for the purchase of compressed natural gas (CNG)/LNG vehicles or the conversion of ferries, locomotives or mine haul trucks.[48] These vehicles in turn create demand for both CNG and LNG. To fuel the CNG/LNG powered vehicles, some customers require access to a fueling station. Pursuant to Direction No. 5 to the BCUC, and approved by Order G-161-12, both the costs and revenues for FEI's NGT program (CNG and LNG service) are part of FEI's natural gas class of service and are included in the delivery charges for all non-bypass customers.[49] As such, the recoveries of FEI's constructed fueling stations, i.e., capital, O&M, and Overhead & Management (OH&M) charges, are included as Other Revenue in FEI's revenue requirement and treated as an offset to the cost of service in the 2023 COSA. The related NGT plant-in-service and O&M expenses are included in FEI's natural gas class of service and functionalized as Distribution, and the costs are classified as part demand-related and part customer-related, as discussed in

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[46] In the matter of FEI's Application for Approval of the Biomethane Energy Recovery Charge (BERC) Rate Methodology.

[47] Pages 75-76.

[48] The undertaking period enabling FEI to incent vehicle conversions to natural gas and to construct CNG and LNG fueling stations ended on March 31, 2022.

[49] Special Direction No. 5 to BCUC, Section 3.

Section 4.1.1.2 above, and allocated to all non-bypass customers. This approach is consistent with the 2016 COSA study.

4.2.2.5 Treatment of Tilbury Phase 1A Expansion Revenues/Costs

The Tilbury Phase 1A Expansion Project (Tilbury 1A) was built as an expansion to FEI's existing LNG facility located in Delta under the framework put in place by Direction No. 5 to the BCUC pursuant to OIC No. 557/2013 to serve LNG sales service (RS 46) customers. The Tilbury 1A expansion included additional liquefaction of 35 TJ per day and a 1 BCF LNG storage tank for the purpose of serving the growing LNG demand both domestically and internationally. The cost recovery of the expenditures associated with the Tilbury 1A expansion through RS 46 is authorized by Direction No. 5 to the BCUC, with any surplus or deficit to be returned to or recovered from all other non-bypass customers. The Tilbury 1A facilities were placed into service in 2018 and were included in FEI's rate base on January 1, 2019.[50]

The Tilbury 1A expansion was included in the 2016 COSA model as a known and measurable change as the cost and associated revenue was not part of FEI's 2016 revenue requirement at that time. FEI's general approach for inclusion of known and measurable changes is to include in its COSA the annual cost of service of the known change. However, as accepted by the BCUC in the 2016 COSA Decision,[51] in its 2016 COSA study, FEI used a 10-year levelized approach for the cost of service and revenues for the Tilbury 1A expansion to reflect that costs are typically high when a new asset enters rate base but the related revenues would grow over time. At that time, as noted by the BCUC in the 2016 COSA Decision, the general approach for including the Tilbury 1A expansion in a COSA could be explored further in a future COSA study when FEI had actual cost and revenue data.[52]

The Tilbury 1A expansion has been in service since 2018. Therefore, as part of the 2023 COSA, FEI reverted to the standard approach for the Tilbury 1A expansion, which was supported by Elenchus in its 2016 COSA Report as the "standard practice".[53] This standard approach is to use the 2023 forecast cost of service and RS 46 revenue that was included in FEI's approved 2023 delivery rates,[54] with any surplus or deficit allocated to all of FEI's non-bypass customers. Additionally, FEI notes that approximately 5 mmcfd of Tilbury 1A's liquefaction capacity out of the total of 33 mmcfd is currently reserved for the Tilbury Base Plant for peak shaving purposes through the interconnect between the Tilbury 1A tank and the Tilbury Base Plant tank, as such the costs related to this 5 mmcfd of Tilbury 1A liquefaction as well as the interconnect between the two facilities are considered to be part of the Tilbury Base Plant for the purpose of the 2023

[50] FEI initially expected the Tilbury 1A facilities to be in service in 2017 and included, as forecast, in FEI's rate base on January 1, 2018 as part of FEI's Annual Review for 2018 Delivery Rates. However, due to a fire incident that occurred in August 2017, the start up of the Tilbury 1A facilities were delayed to the end of 2018. The 2018 cost of service related to the Tilbury 1A expansion was returned to customers through FEI's flow-through deferral account as described in Section 12.4.2.2 of FEI's Annual Review for 2019 Delivery Rates.

[51] 2016 COSA Decision, page 13.

[52] 2016 COSA Decision, page 14.

[53] Exhibit A2-2 of FEI's 2016 RDA, Elenchus COSA Report, page 22.

[54] Decision and Order G-352-22.

COSA. Table 4-4 below presents the 2023 forecast of RS 46 revenue as well as the cost of service of Tilbury 1A, excluding the costs of the 5 mmcfd of liquefaction and the interconnect, that is included in the 2023 COSA.

Table 4-4: Tilbury Phase 1A Cost and Revenues (Delivery Only) included in 2023 COSA ($ millions)

2023 Forecast	Amount ($millions)
Tilbury Phase 1A Cost of Service, excl. Cost of Gas	62.343
RS 46 Revenue (Delivery Only)	28.474
Surplus/(Deficit)	**$ (33.869)**

4.2.3 Known and Measurable Changes to Test Year Revenues and Costs

In addition to costs from FEI's 2023 test year, the 2023 COSA also includes known and measurable changes that have occurred since the costs were established for the 2023 test year (i.e., approved by the BCUC through the 2023 Annual Review) as well as projects that are approved by the BCUC and expected to be in-service by or soon after January 1, 2025 (i.e., not included in the 2023 test year costs and rates).

Table 4-5 below summarizes the known and measurable changes, which include adjustments to the RS 22 firm revenue and contract demand as well as three large major projects[55] that have been approved by the BCUC which are expected to be in-service or close to their in-service dates by the effective date sought for implementation of the proposals in this Application, if approved, which is January 1, 2025. The rate base and cost of service of these known and measurable changes are included in the 2023 COSA and functionalized, classified, and allocated with existing costs as required.

[55] FEI's Advanced Metering Infrastructure (AMI) CPCN Project was approved by Order C-2-23 dated May 15, 2023. However, since the full deployment of AMI is not expected to be complete with all new assets entering rate base until 2027, FEI did not include the AMI CPCN Project as a Known and Measurable Change in the 2023 COSA.

Table 4-5: Summary of Known and Measurable Changes Included in 2023 COSA Study

Adjustments or Major Projects	Expected In-effect or In-Service Date	Change in Mid-Year Rate Base in 2023 COSA ($ millions)	Change in Cost of Service in 2023 COSA ($ millions)	Change in Firm Contract Demand in 2023 COSA (TJ/day)
RS 22 Firm Revenue and Contract Demand	2023	-	-	4.3
Inland Gas Upgrade (IGU) CPCN	2024 (Remaining Phase Only)	165.603	13.931	n/a
Coastal Transmission System Integrity Management Capabilities (CTS-TIMC) CPCN	2023, 2024, and 2025 (Complete in phases)	102.850	8.334	n/a
Gibsons Capacity Upgrade Project	2024	10.927	1.150	n/a
Total		**279.380**	**23.415**	**4.3**

4.2.3.1 RS 22 Firm Revenue and Contract Demand Adjustments

When the 2023 forecasts were developed as part of FEI's Annual Review for 2023 Delivery Rates in mid-2022, there were only three RS 22 firm customers (the other RS 22 customers were fully interruptible). However, in late 2022, FEI had 10 additional RS 22 firm customers for a total of 13 customers with a firm demand commitment. The additional RS 22 firm customers resulted in an increase to the contract demand by approximately 4.3 TJ/day under RS 22 firm, from 1.5 TJ per day to 5.8 TJ per day, and approximately $2.4 million of additional RS 22 firm revenue.

For clarity, the additional RS 22 firm revenue has no overall impact to the cost of service in the 2023 COSA reflected in Table 4-5 above. The 10 additional RS 22 firm customers were previously fully interruptible customers under RS 22; therefore, reclassing existing interruptible demand to firm demand does not increase the overall revenue or cost of service in the 2023 COSA model since the interruptible charge under RS 22 is set to equal the effective charges for firm demand (i.e., Firm Demand Charge per Month plus the Firm MTQ Delivery Charge per GJ).

However, the additional RS 22 firm customers will have a material impact on the cost allocation in the 2023 COSA given the increase in contract firm demand. This is because various costs, including the Tilbury LNG facilities and transmission related costs, are allocated based on the peak day demand/contract demand of each rate schedule. Accordingly, using the forecasts from the 2023 Annual Review without considering the known and new RS 22 firm customers would result in an under-allocation to RS 22 firm customers. As such, as part of the 2023 COSA, FEI included the additional firm RS 22 customers for cost allocation purposes.

FEI also notes that, consistent with the 2016 COSA and as accepted by the BCUC in the 2016 COSA Decision, the R:C ratios for RS 22 firm customers are calculated and included in the 2023 COSA schedules while the revenues of RS 22 interruptible customers are treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules.

4.2.3.2 Inland Gas Upgrade (IGU) Project CPCN

The IGU project CPCN application was approved by the BCUC in its Decision and Order G-12-20, dated January 1, 2020. The IGU project includes upgrades to 29 pipeline laterals in the Interior of British Columbia to accommodate in-line inspection tools. The IGU project addresses pipeline integrity risks associated with pipelines that operate at a stress level that has the potential for pipeline rupture due to external corrosion that cannot be detected using current pipeline integrity methods. The IGU project has been implemented in multiple phases since 2020 and FEI has been including the associated costs in rate base as the assets of the individual phases are placed in-service. To date, FEI has included approximately $192.2 million in rate base from 2021 to 2023 (actual for 2021 and 2022, forecast for 2023). The total estimated capital cost for the project is approximately $360 million, including AFUDC. FEI is expecting the project will complete and all remaining assets will be placed in-service by the end of 2024. Therefore, FEI has included the undepreciated mid-year (2025) rate base of approximately $165.603 million and the cost of service of approximately $13.931 million in its 2023 COSA.

4.2.3.3 Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) Project CPCN

The CTS-TIMC project CPCN application was approved by the BCUC in its Decision and Order C-3-22, dated May 18, 2022. The CTS-TIMC project consists of alterations to FEI's CTS to allow FEI to run electro-magnetic acoustic transducer (EMAT) in-line inspection (ILI) tools on 11 pipelines that were deemed susceptible to cracking threats. These alterations are expected to be constructed in 2023 and 2024, with the project being completed by the end of 2025. The total estimated capital cost for the CTS-TIMC project, including AFUDC, is approximately $137.8 million. Therefore, FEI has included the undepreciated mid-year (2025) rate base of approximately $102.850 million and the cost of service of approximately $8.334 million in its 2023 COSA.

4.2.3.4 Gibsons Capacity Upgrade (GCU) Project

The GCU project was approved by the BCUC in its Decision and Order G-352-22 as part of FEI's Annual Review for 2023 Delivery Rates.[56] The community of Gibsons is currently supplied with natural gas by a 19 km Intermediate Pressure (IP) pipeline from the Sechelt Gate Station which is in turn served by FEI's Vancouver Island Transmission System (VITS). The capacity of the IP pipeline is insufficient to meet current peak demand such that FEI is currently unable to supply sufficient capacity to the community during design conditions without the support of a temporary contracted CNG trailer on-site during winter months. The GCU project involves a new local CNG peak shaving storage facility that will be used to offset peak demand currently unable to be supported by the existing IP pipeline. The GCU project is expected to be completed in 2024, entering FEI's rate base on January 1, 2025. The total forecast capital cost, including AFUDC, for the GCU project is $12.194 million. Therefore, FEI has included the undepreciated mid-year

[56] Page 24.

(2025) rate base of approximately $10.927 million and the cost of service of approximately $1.150 million in its 2023 COSA.

4.2.4 Final Revenue Requirement and Rate Base for 2023 COSA

Tables 4-6 and 4-7 below provide the final revenue requirement and rate base, respectively, that are used in the 2023 COSA for allocation, including all adjustments related to the assumptions discussed in Section 4.2.2 and all known and measurable changes discussed in Section 4.2.3.

Table 4-6: Final Delivery and Gas Costs used in 2023 COSA

Particular	Reference		Amount ($millions)
Delivery Costs	Table 4-1 (excl. Cost of Gas)	$	1,078.3
Less: Bypass, Contract Customers and RS 46	Section 4.2.2.2 and 4.2.2.5	$	(47.3)
Add: Known and Measureable Changes	Table 4-5	$	23.4
Final Delivery Costs for 2023 COSA	**Table 4-8**	**$**	**1,054.5**
Cost of Gas	Table 4-1	$	1,170.8
Less: Bypass, Contract Customers and RS 46	Section 4.2.2.2 and 4.2.2.5	$	(36.5)
Final Gas Costs for 2023 COSA	**Table 4-15**	**$**	**1,134.3**

Table 4-7: Final Rate Base used in 2023 COSA

Particular	Reference		Amount ($millions)
Rate Base	Table 4-2		5,943.4
Less: Biomethane	Section 4.2.2.3		(56.4)
Add: Known and Measureable Changes	Table 4-5		279.4
Final Rate Base for 2023 COSA	**Appendix D, Schedule 3**	**$**	**6,166.4**

4.3 *DELIVERY COSTS ALLOCATION*

In this section, FEI presents the allocation of the final 2023 COSA delivery costs (as presented in Section 4.2.4 above) to each rate schedule, using the same three-step functionalization, classification, and allocation process described in Section 4.1.1 above.

4.3.1 Functionalization

FEI has functionalized its 2023 test year revenue requirement into the major categories that reflect the utility's plant investment code of accounts and services provided to customers. After assigning plant costs functionally, related expenses are also functionalized along the same basis. The results of the functionalization are included in Appendix D, Schedule 2.

Each of the functions is described further below.

4.3.1.1 Gas Supply Operations

FEI's Gas Supply Operations function includes costs related to gas control, company use gas and an allocation of general costs and intangible plant costs and expenses.

4.3.1.2 LNG Facilities

FEI's LNG facilities include the Tilbury LNG Facility and the Mt. Hayes LNG Facility. Both LNG functions include the direct plant-in-service of both facilities, the direct costs related to the O&M of the facilities, as well as an allocation of the general and intangible plant costs and expenses.

The Tilbury LNG facilities are separated into two separate functions, the Tilbury Base Plant and the Tilbury 1A expansion.

4.3.1.2.1 TILBURY (BASE PLANT) LNG STORAGE FACILITY

The Tilbury Base Plant LNG storage facility was constructed in 1971, principally for use as a peaking resource for the supply of gas on extreme cold weather days. The Tilbury Base Plant is also used to support transmission and distribution operations during maintenance and repair activities, emergency outage, and supply constraints. As noted in Section 4.2.2.5 above, the Tilbury Base Plant is currently being served by the liquefaction equipment of Tilbury 1A through the interconnect between the Tilbury Base Plant tank and the Tilbury 1A tank. As such, the cost related to the 5 mmcfd of liquefaction reserved for the Tilbury Base Plant as well as the interconnect between the two facilities are considered part of the Tilbury Base Plant for the purpose of the 2023 COSA and therefore functionalized as part of the Tilbury Base Plant.

Since the 1993 Phase B RDA, the costs of the Tilbury Base Plant have been allocated on a peak day demand basis to firm sales and transportation service customers, which include Residential (RS 1), Small and Large Commercial (RS 2, 3, and 23), NGV (RS 6), General Firm Service (RS 5 and 25), and Large Firm Industrial Service (RS 22 Firm). For clarity, Large Commercial, General Firm Service, and Large Firm Industrial Service customers are included in the allocation because the Tilbury Base Plant also supports the supply and delivery to these customers during peak days. However, Seasonal (RS 4), General Interruptible Service (RS 7 and 27) and Fully Interruptible Large Industrial Service (RS 22 Interruptible) customers are not allocated any costs related to the Tilbury Base Plant as these customers would be curtailed on the days of extreme cold weather to preserve the capacity of the system to serve the firm load.

4.3.1.2.2 TILBURY PHASE 1A EXPANSION

As discussed in Section 4.2.2.5, the Tilbury 1A expansion has been in service since 2018 and the related costs were included in FEI's rate base on January 1, 2019. The Tilbury 1A expansion was included in the 2016 COSA study as a known and measurable change and at that time was functionalized in the same way as the Tilbury Base Plant, which was that the associated costs were allocated on a peak day demand basis to firm customers only (i.e., excludes RS 4, RS 7/27, and RS 22 Interruptible).

The Tilbury 1A expansion was built for the purposes of supporting the growing domestic LNG demand for NGT and has been in-service since 2018, with the LNG sales revenue recorded as RS 46 revenue. The charges for RS 46 are set separately from FEI's revenue requirement as set out in RS 46, which was authorized by Direction No. 5 and amended from time to time by approval of the BCUC. In addition, Direction No. 5 established that the Tilbury 1A facilities be included in the utility's natural gas class of service rate base with utility rates set so as to include the annual revenues from the sale of LNG and the annual cost or service of the Tilbury 1A expansion facilities. Therefore, the cost of service for the Tilbury 1A expansion is included in rates for all non-bypass customers, including both firm and interruptible, and all RS 46 revenues are treated as an offsetting credit to all non-bypass customers by way of a reduction in delivery rates in FEI's annual review each year, again for both firm and interruptible customers. This means that if FEI were to use the allocation approach in the 2016 COSA study, all interruptible customers would benefit from the offsetting RS 46 revenue but would not have any costs allocated to them since the costs in the 2016 COSA study were allocated based on the peak day demand to only firm customers.

Given the RS 46 revenue associated with the Tilbury 1A expansion benefits all non-bypass firm and interruptible customers, FEI has functionalized the Tilbury 1A expansion separately from the Tilbury Base Plant and allocated the related costs to all non-bypass customers based on the delivery cost of service margin of each rate schedule in the 2023 COSA. This approach aligns the costs and revenues related to the Tilbury 1A expansion and ensures all non-bypass customers, including both firm and interruptible, will be allocated both the related costs and revenues.

4.3.1.2.3 MT. HAYES LNG FACILITY

As the Mt. Hayes LNG facility has a different function than the Tilbury LNG facilities, its costs and revenues are allocated differently. The Mt. Hayes LNG facility went into service in 2011 and has a dual purpose of serving as 1) a gas supply storage facility and 2) a transmission facility which, similar to pipeline looping or compression, provides additional transmission system capacity.

FEI currently credits approximately $18 million to Other Revenue in its revenue requirement while debiting the same amount to the midstream costs. This results in a transfer of costs from FEI's delivery cost of service, where the cost of transmission is accounted for, into FEI's midstream costs, where storage is accounted for. Under this treatment, all non-bypass customers receive an allocation of the Mt. Hayes facility through the delivery rates of each rate schedule to account for the transmission purpose of the Mt. Hayes facility, while only the sales customers will receive an allocation of the Mt. Hayes facility through their storage and transport charge for the storage purpose of the facility.

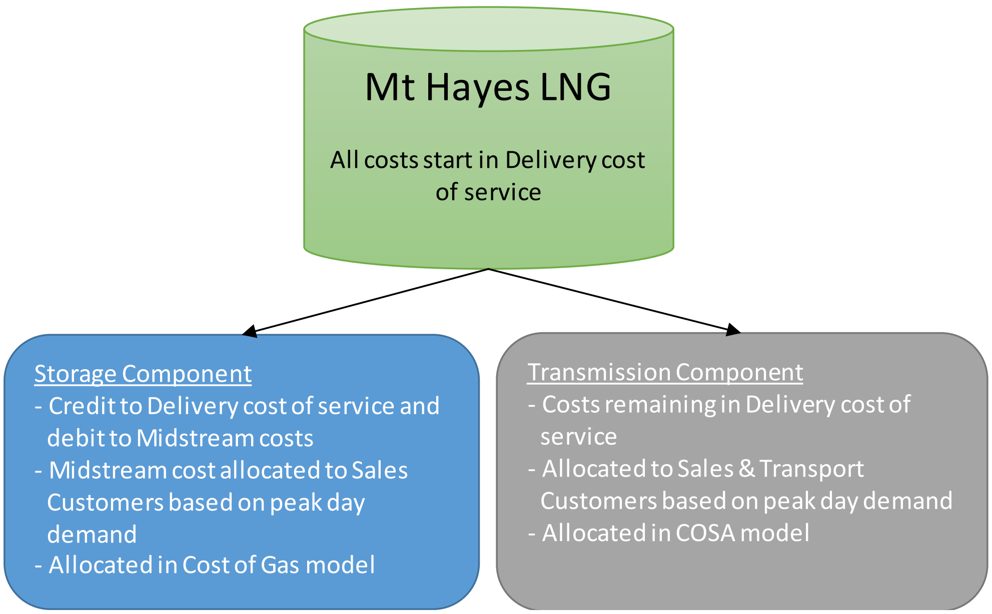
This treatment of the cost allocation for the Mt. Hayes LNG facility is consistent with the 2016 COSA, and was approved by the BCUC in the 2016 COSA Decision,[57] and supported by Elenchus in their COSA Report where they identified that FEI's treatment is unique, but "this unique

[57] 2016 COSA Decision, page 16.

treatment reflects the unique role that Mt. Hayes LNG Storage serves in the FEI system."[58] Elenchus also acknowledged that FEI's treatment of Mt. Hayes costs "is appropriate to reflect the multi-faceted role of the facility in the cost of service allocation methodology."[59]

Figure 4-3 below depicts how the costs of the Mt. Hayes LNG facility are split between delivery and midstream charges.

Figure 4-3: Mt. Hayes Storage and Transmission Costs



4.3.1.3 Transmission

FEI's Transmission function includes costs related to the transmission pipeline assets, compression, right of way and related maintenance, measurement control operations, and transmission supervision. It also includes an allocation of general and intangible plant costs and expenses. FEI is approved to credit Other Revenue for the Southern Crossing Pipeline (SCP) capacity from the Midstream Cost Reconciliation Account (MCRA).[60] As such, the Transmission function also includes this credit related to the SCP capacity.

4.3.1.4 Distribution

FEI's Distribution function includes costs related to the distribution pressure and intermediate pressure pipe assets, meter installation and exchange, service lines, preventative maintenance,

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58 Exhibit A2-2 in the 2016 RDA Proceeding, page 10.
59 Ibid.
60 As approved in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20 (page 17), effective November 1, 2020, FEI is approved to debit the MCRA and credit Other Revenue in the amount of $346.617 per MMcfd.

field training, distribution pipe operations costs emergency management and an allocation of general costs and intangible plant costs and expenses.

4.3.1.5 Marketing

FEI's Marketing function includes costs related to energy solutions, energy efficiency operating costs and amortization, resource planning and market development, and external relations. This function also includes an allocation of general costs and intangible plant costs and expenses.

4.3.1.6 Customer Accounting

FEI's Customer Accounting function includes costs related to administering FEI's customers including computer hardware and software, leasehold improvements, furniture, equipment and structures, customer billing, customer assistance, credit and collections, customer service supervision and an allocation of general costs and intangible plant costs and expenses. The related expenses follow the same functionalization.

4.3.1.7 Functionalization Summary

Table 4-8 below summarizes the functionalization results of the total delivery cost of service of $1,054.5 million (as shown in Table 4-6) in the 2023 COSA. Further details of the functionalization summary are presented in Schedule 2 of Appendix D.

Table 4-8: Delivery Cost of Service Functionalization Summary

Function	($ millions)	Percentage of Total
Gas Supply Operations	11.0	1.0%
Tilbury Base LNG Storage	17.9	1.7%
Tilbury Phase 1A Expansion	33.9	3.2%
Mt. Hayes LNG Storage	7.0	0.7%
Transmission	266.6	25.3%
Distribution	599.4	56.8%
Marketing	80.0	7.6%
Customer Accounting	38.8	3.7%
Total	**1,054.4**	**100.0%**

4.3.2 Classification

The second step of the COSA study is to classify the functionalized costs into the cost-causation categories of system demand, energy delivery, and number of customers. There is no change in FEI's classification in the 2023 COSA from the 2016 COSA study. As noted in the Elenchus COSA Report in the 2016 COSA study proceeding, Elenchus agreed with the classification method used in FEI's 2016 COSA study and was not aware of any other classification method used in COSA studies.[61]

The following sections discuss the classification of plant costs and related expenses for each of the functionalization categories.

4.3.2.1 Gas Supply Operations

As discussed in Section 4.3.1.1, the delivery costs that are functionalized as Gas Supply are primarily related to gas control and company use gas. These costs are classified as Energy-related as they vary by the volume of gas delivered to customers. For the classification and allocation of the gas (commodity) costs, please refer to Section 4.4.3 below.

4.3.2.2 LNG Facilities

4.3.2.2.1 TILBURY (BASE PLANT) LNG STORAGE

As discussed in Section 4.3.1.2.1, the existing Tilbury Base Plant is a peaking facility designed predominantly to be used on the extreme cold weather days. The Tilbury Base Plant was included as a function in FEI's 1993, 1996, 2001, and 2016 rate design proceedings, and has been consistently classified as demand-related in each of these proceedings. FEI has maintained this classification for the Tilbury Base Plant in this 2023 COSA.

4.3.2.2.2 TILBURY PHASE 1A EXPANSION

As discussed in Section 4.3.1.2.2, the Tilbury 1A expansion has been in service since 2018 for supporting the growing LNG sales demand both domestically and internationally. The costs related to the Tilbury 1A expansion are functionalized separately from the Tilbury Base Plant. Since the sales of LNG through RS 46 are credited back to all non-bypass customers through the delivery rates of each rate schedule, FEI is also allocating the related costs of the Tilbury 1A expansion based on the delivery margin of each of these rate schedules in the 2023 COSA.

4.3.2.2.3 MT. HAYES LNG FACILITY

As discussed in Section 4.3.1.2.3, the costs related to the Mt. Hayes LNG facility are split into two separate components: the storage component allocated to FEI's midstream costs and the transmission component allocated to FEI's delivery costs. Consistent with historical treatment, FEI has been classifying the delivery costs portion of the Mt. Hayes LNG facility as demand-related and the costs are allocated to all non-bypass customers on a peak day demand basis. For the storage component, sales customers receive an allocation of the Mt. Hayes facility through their storage and transport charge as part of FEI's gas costs. Please refer to Section 4.4 for the allocation of gas costs, which would include the storage component of the Mt. Hayes LNG facility.

[61] Exhibit A2-2, Elenchus COSA Report, page 15.

4.3.2.3 Transmission

Consistent with the 2001, 2012, and 2016 COSA studies, FEI's transmission functions are classified as fully demand-related, since system capacity requirements are driven by the peak demand of each customer group.

4.3.2.4 Distribution

As discussed in Section 4.1.1.2, distribution costs are considered to be caused by multiple factors and cannot be wholly classified into either demand-related or customer-related. FEI uses the MSS approach with PLCC adjustment to determine the split between the demand-related and customer-related classification for distribution related costs.

In the Elenchus COSA Report on FEI's 2016 COSA study, Elenchus stated that the use of MSS with a PLCC adjustment is an accepted method for classifying distribution related assets and costs based on Elenchus' experience. Elenchus also noted that the MSS method was applied more often by utilities than the zero-intercept method, an alternative that is also an accepted classification method for distribution related assets and costs.[62] In the 2016 COSA Decision, the BCUC determined the method to be reasonable for use in COSA studies.[63]

4.3.2.4.1 MINIMUM SYSTEM STUDY (MSS)

The MSS determines the proportion of distribution costs that are customer-related versus demand-related. It assumes a certain level (i.e., percentage) of the distribution plant is required to serve the minimum load requirements of customers throughout the service territory, which means the costs of the minimum system are dependent on the number of customers regardless of their level of demand. For example, the closer a certain asset is located to a customer, the more of that particular asset is related to the requirement of that specific customer rather than their demand. As such, costs associated with such assets should be regarded as customer-related. The remaining percentage of costs are then classified as demand-related since any cost associated with the distribution system beyond the minimum system requirement is considered to be due to the customers using the system to deliver a quantity of gas that is greater than the level that the minimum system can serve.

The MSS is only applicable to distribution mains. It examines the various mains in place at the utility and separates the mains by pipe diameter and material (steel or polyethylene). For the purpose of the MSS, FEI assumes the minimum distribution system is comprised of all pipe diameters equal to or less than 60 mm. The results of the MSS for the 2023 COSA are based on actual 2022 data, with the customer-related component and the demand-related component each approximately 50 percent. The results as well as the detailed calculations are presented in Appendix E.

[62] Exhibit A2-2 of FEI's 2016 RDA, Elenchus COSA Report, page 15. Also 2016 COSA Decision, page 10.
[63] 2016 COSA Decision, page 18.

The costs of meters and services are fully classified as customer-related as each customer needs a meter and service regardless of the demand or volume of service taken by the customer.

4.3.2.4.2 PEAK LOAD CARRYING CAPABILITY (PLCC) ADJUSTMENT

While the minimum system is designed, in theory, to connect customers and not deliver gas, the actual design of the mains is capable of carrying some load that is beyond zero. Therefore, the proportion of costs allocated to the customer-related component could be overstated. This over-statement is commonly addressed with an adjustment that takes into consideration the demand that can be supplied through the minimum system and is referred to as the PLCC adjustment.

The PLCC adjustment involves determining the theoretical capacity of the minimum system. This is done by first determining the average minimum system capacity per customer by dividing the capacity of the minimum system with the number of customers served by the distribution system. This result is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the peak demand of each rate class, resulting in an adjusted peak demand, which is then used to allocated demand-related distribution assets and costs. The PLCC adjustment effectively adjusts the proportion of costs allocated to the customer-related component to a more representative level.

Based on a minimum distribution system of 60 mm PE in diameter, as discussed in the MSS section above, the PLCC adjustment for the 2023 COSA is calculated to be 0.206 GJ per day per customer. The detailed calculation of the PLCC adjustment is presented in Appendix E.

4.3.2.5 Marketing and Customer Accounting

The Marketing and Customer Accounting functions are generally classified as customer-related. This methodology is consistent with past practice and is appropriate, as the underlying cost causation for these functions is directly related to the customers served under each rate schedule and not based on their volumetric usage or demand. One exception is Demand Side Management (DSM) expenditures which are classified as energy-related since DSM programs reduce overall throughput via energy conservation. For the purposes of allocating costs to each customer class, FEI developed separate customer weighting factors for customer administration and billing, as described further in Section 4.3.3.3.

4.3.2.6 Classification Summary

Table 4-9 below summarizes the results of the delivery cost of service classification from the 2023 COSA. Further details of the Classification are presented in Schedule 4 of Appendix D.

Table 4-9: Delivery Cost of Service Classification Summary

Classification	$ millions	% of Total
Energy	52.6	5.0%
Demand	521.3	49.4%
Customer	480.6	45.6%
Total	**1,054.4**	**100.0%**

4.3.3 Allocation

The third step of the COSA study is to allocate the classified functions to each of the rate schedules based on an appropriate allocator. FEI has, for the most part, allocated all cost components to its rate schedules based on approaches consistent with past practice. In the 2016 RDA, Elenchus reviewed these approaches in their COSA Report and agreed with the allocators used by FEI,[64] which were also accepted by BCUC in the 2016 COSA Decision.[65]

FEI allocates costs in the 2023 COSA on the basis of:

- Volume/Load for energy-related classification;
- Peak-day demand for demand-related classification; and
- Weighting factor for customer-related classification.

Each of these allocators is discussed separately in the sections that follow.

4.3.3.1 Energy-Related Allocation

Within the 2023 COSA, there is approximately $52.6 million of costs that have been classified as energy-related. These costs include approximately $11.0 million of gas supply operations related costs such as company use gas and gas control, as discussed in Section 4.3.1.1. The remaining $41.6 million of costs are all related to the amortization of the DSM deferral account in the 2023 test year. All of these costs are allocated using the energy (volume in TJ) delivered by each rate schedule under the 2023 Test Year as provided in Table 4-10 below.

[64] Exhibit A2-2 of FEI's 2016 RDA, Elenchus COSA Report, page 17-18.
[65] 2016 COSA Decision, G-4-18, page 11.

Table 4-10: Annual Volume (TJ) by Rate Schedule (non-bypass) for Allocation

Rate Schedule	Annual Volumne (TJ)
1	82,890
2	29,204
3	25,770
23	3,904
4	166
5	10,827
25	8,303
6	21
7	6,004
27	4,289
22	12,373
22A	7,669
22B	7,481
Total	**198,901**

4.3.3.2 Demand-Related Allocation

Consistent with FEI's 1993, 1996, 2001, 2012, and 2016 RDAs, FEI has used the coincident peak (CP) approach to allocate demand-related costs to each rate schedule. This reflects the fact that FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers.

While Elenchus noted in the 2016 RDA that non-coincident peak (NCP) is used by electric utilities,[66] FEI does not use NCP for the following reasons:

- FEI does not have the necessary metering in place in order to calculate NCP by customer class;
- The majority (approximately 80 percent) of FEI's customer volumes are heat sensitive and the NCP would be the same as their coincident demand in the peak day; and
- FEI's system is designed to satisfy the demand during the peak day.

Elenchus accepted FEI's reasons for using CP as an allocator for distribution costs instead of NCP[67] and, in the 2016 COSA Decision, the BCUC also accepted the use of CP for allocating demand-related costs, including distribution costs.[68]

[66] Exhibit A2-2 of FEI's 2016 RDA, Elenchus COSA Report, page 17.
[67] Exhibit A2-2 of FEI's 2016 RDA, Elenchus COSA Report, page 18.
[68] COSA Decision, G-4-18, page 11.

The CP of each rate schedule for allocation purposes is calculated based on a three-year weighted-average load factor (LF) and the annual volume of each rate schedule as follows:

CP (or Peak Day Demand) = Annual Consumption / (3-year w-avg. LF x 365 days)

The three-year weighted average LF is calculated based on the annual LF by region and by rate schedule using the number of customers per rate schedule in each region. Furthermore, the annual LF by region and by rate schedule is calculated based on an estimate of the peak day demand for each rate schedule on a regional basis using the regional temperature and a regression analysis that uses average monthly temperature and actual demand data for 10 months (excludes July and August).

Table 4-11 below provides the load factors and peak day demand of each rate schedule used in the 2023 COSA. Consistent with past practice, RS 6 (Natural Gas Vehicles) has been assigned a 100 percent load factor for determination of its peak day demand since this class of customers is not heat sensitive. Additionally, RS 4 (Seasonal) and RS 7/27 (General Interruptible Service) are assigned no peak day demand since these rate schedules are fully interruptible and, thus, do not drive system capacity additions. Therefore, no demand-related costs are allocated to these customers. Finally, FEI included the firm demand commitments for RS 22 (Large Volume Transportation Service), RS 22A (Transportation Service Inland Area – Closed) and RS 22B (Transportation Service Columbia Area – Closed) in the table below as FEI is obligated to deliver their agreed firm quantity. Essentially, the sum of the heat sensitive rate schedules' peak day demand (i.e., RS 1, 2, 3, 23, 5, 25, and 6) and the firm contractual commitments (i.e., RS 22, 22A, and 22B) is equal to FEI's total peak day demand.

Table 4-11: Load Factors and Peak Day/Firm Demand by Rate Schedule for Allocation[69]

Rate Schedule	Load Factor	Peak Day or Firm Demand (TJ/Day)
1	31.3%	726.1
2	30.4%	263.3
3	36.0%	195.9
23	35.7%	30.0
4	n/a	-
5	53.6%	55.3
25	61.6%	37.0
6	100.0%	0.1
22	n/a	5.8
22A	n/a	24.7
22B	n/a	14.9
7	n/a	-
27	n/a	-
Total		**1,353.0**

4.3.3.3 Customer-Related Allocation

Customer-related costs are allocated across rate schedules either directly, based on the average number of customers (i.e., no adjustment), or are allocated based on the weighting factor adjusted average number of customers.

For customer-related costs such as distribution land, structures, mains, measuring and regulating equipment that are not specifically tied to any rate schedules (i.e., they are required because of the distribution system as a whole rather than one or two specific rate schedules), they are allocated directly using the average number of customers by rate schedule. Table 4-12 below provides the average number of customers for the 2023 Test Year by rate schedule used for the allocation.

69 Includes known and measurable changes related to RS 22 Firm, i.e., additional firm demand of 4.3 TJ/day as discussed in Section 4.2.3.1.

Table 4-12: Average Number of Customers by Rate Schedule (non-bypass) for Allocation

Rate Schedule	Customers (No.)
1	977,501
2	90,632
3	7,049
23	701
4	18
5	632
25	272
6	13
7	45
27	70
22	24
22A	9
22B	5
Total	**1,076,971**

For customer-related costs such as distribution service lines, meters, customer billing, and customer contact services for supporting infrastructure and energy solutions that will not cost the same to connect to FEI's system or to administer between the different customer groups, they are allocated using the weighting factor adjusted average number of customers. For the purposes of the 2023 COSA, FEI developed two types of weighting factors for adjusting the average number of customers:

- a weighting factor for costs related to Meters and Distribution Services; and
- a weighting factor for costs related to Administration and Billing.

Table 4-13 below shows the weighting factors for meters/services and for administration/billing, which are calculated for each rate schedule relative to the residential rate schedule.[70] For clarity, the allocations for these costs will be based on the average number of customers from Table 4-12 above multiplied by the weighting factors of each rate schedule shown in Table 4-13 below.

[70] FEI's residential rate schedule (RS 1) is used as the base upon which to weight against other rate schedules because it is the least costly rate schedule to connect and administer. For this reason, the weighting study shows the residential rate schedule with a factor of 1.0.

Table 4-13: Customer Weighting Factor Study and Customer Administration Factor Results

Rate Schedule	Customer Weighting Factor	Customer Admin & Biling Factor
1	1.0	1.0
2	2.1	1.1
3	9.1	2.0
4	15.4	25.6
5	15.8	25.3
6	19.3	1.0
7	48.7	75.5
22	97.8	137.8
22A	309.5	137.8
22B	669.6	137.8
23	11.7	21.5
25	20.8	25.6
27	48.7	78.1

The following sections provide further details on the two weighting factors.

4.3.3.3.1 WEIGHTING FACTOR FOR METERS AND SERVICES

The facility costs for the distribution system, such as meters, service lines and regulators, are not equal among all customers. Therefore, for these costs, FEI applies a weighting factor to the average number of customers in each rate schedule so that the costs allocated to each rate schedule are proportionate to the costs to serve them.

The weighting factors for meters and services are based on the average value of meter and service assets associated with each specific rate schedule relative to RS 1. For example, industrial customers are installed with bigger rotary meters and service lines, while residential customers are installed with smaller diaphragm meters and service lines; therefore, the average cost (i.e., including meter, service line, regulators and customer service) for industrial customers under RS 5 (i.e., approximately $29,545 per customer in 2022) is higher than the average cost for residential customers (i.e., approximately $1,872 per customer in 2022). In order to reflect the fact that an industrial customer under RS 5 has higher meter and service-related costs than a residential customer, the average number of customers under RS 5 would be multiplied by 15.8 for the purpose of allocating meter and service-related costs in the COSA model (i.e., Customer Weighting Factor as per Table 4-13 above which is equal to $29,545 divided by $1,872). If this adjustment were not included, then the allocation of customer-related costs for meters and services would assume that an industrial customer has the same average meter and service-related costs as a residential customer. As such, following this approach, the weighting factors by rate schedule developed based on the average meters and services per customer will help to ensure each rate schedule is allocated the appropriate proportion of customer-related costs for meters and services based on both the average number of customers as well as the cost causation of each customer group.

4.3.3.3.2 WEIGHTING FACTOR FOR ADMINISTRATION AND BILLING

Large customers generally require a greater level of administrative effort or customer service than the average residential customer. As such, customer weighting factors are required to properly allocate customer administration, marketing, and billing related costs to the various rate schedules.

Based on information from FEI's marketing, customer service and billing departments, weighting factors for each rate class were developed which take into consideration:

- the frequency of meter reading;
- the use of remote meter reading via cellular or other communications infrastructure and the method of collecting and retaining load data;
- the amount of time spent by customer service responding to inquiries;
- marketing programs and costs for different customer groups;
- the existence of dedicated account managers for commercial and industrial customers; and
- the number of resources dedicated to each customer class for customer billing, measurement, and marketing.

For example, based on the estimated costs by FEI's marketing, customer service, and billing departments for each customer group, the average cost related to administration and billing for a residential customer is estimated to be approximately $40.80 per customer. In comparison, the average cost for an industrial customer under RS 5, which would include dedicated resources such as industrial sales managers, is estimated to be approximately $1,030.00 per customer. Therefore, in order to reflect the fact that an industrial customer under RS 5 would have a higher administration and billing cost than a residential customer, the average number of customers under RS 5 would be multiplied by 25.3 times for the purpose of allocating administration and billing-related costs in the COSA model (i.e., Customer Admin & Billing Factor in Table 4-13 above which is equal to $1,030.0 divided by $40.80). This approach will ensure the customer-related costs for administration and billing will be allocated with the appropriate proportion based on both the average number of customers as well as the cost causation of each customer group.

4.3.3.4 Delivery Costs Allocation Summary

Table 4-14 below summarizes the allocation results of the delivery cost of service. Further details of the classification are presented in Schedule 4 of Appendix D.

Table 4-14: Delivery Cost of Service Allocation to Rate Schedules Including Known and Measurable Changes

Rate Schedule	($millions)	Percentage of Total
1	693.5	65.8%
2	176.4	16.7%
3/23	119.0	11.3%
4	0.1	0.0%
5/25	45.0	4.3%
6	0.1	0.0%
7/27	3.1	0.3%
22	3.0	0.3%
22A	8.5	0.8%
22B	5.9	0.6%
Total	**1,054.4**	**100.0%**

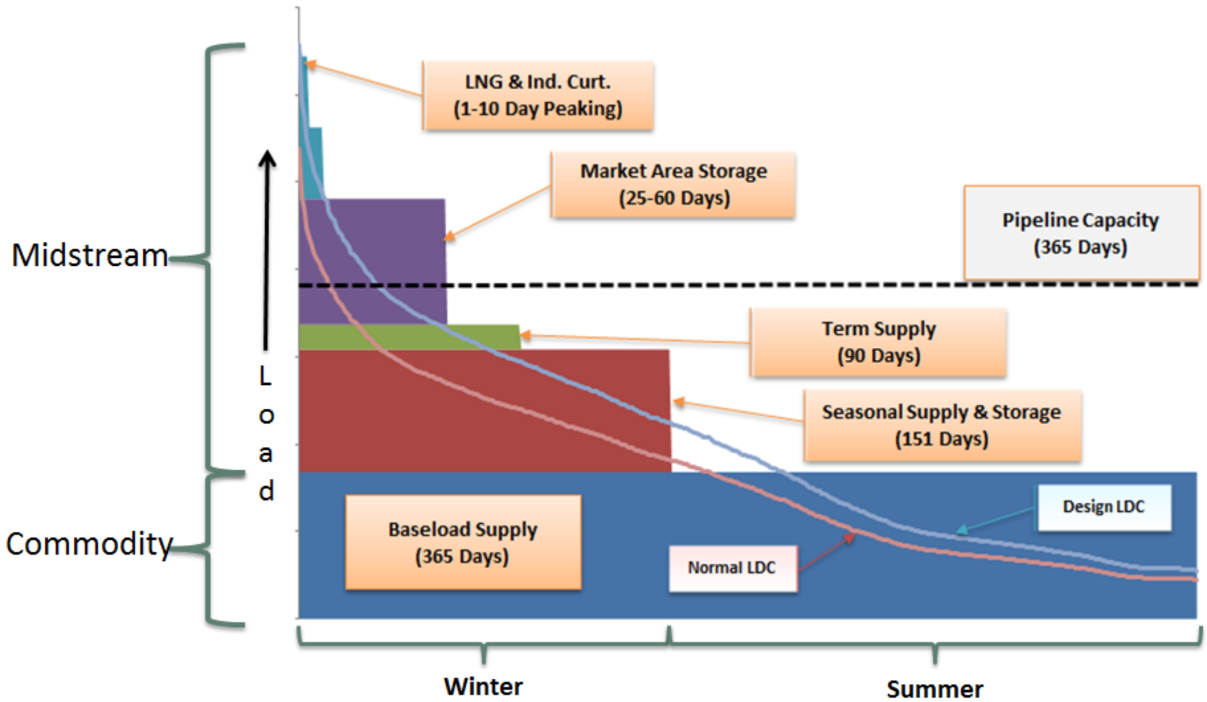
The total delivery cost of service of $1,054.5 million as shown in Table 4-14 above includes the revenues from bypass and contract customers as credits, as well as the adjustments due to known and measurable changes. It also includes the revenue from the RS 46 LNG sales service and the related costs of Tilbury 1A that are allocated to all non-bypass customers, i.e., any surplus or deficit from the LNG services are allocated to all non-bypass customers in the 2023 COSA model as discussed in Section 4.2.2.5.

4.4 GAS COSTS ALLOCATION

FEI incurs gas costs on behalf of all core market customers to meet peak customer demand. FEI's gas costs are separated into commodity and storage and transport costs, which correspond to two of the components on a customer's bill. Commodity costs correspond to the Cost of Gas component of a customer's bill (also called the Commodity Cost Recovery Charge within the gas tariffs, or more simply referred to as the commodity charge). The storage and transport costs (also referred to as midstream costs) correspond to the Storage & Transport component of a customer's bill.

FEI's gas costs are illustrated below in Figure 4-4, which shows how FEI's gas resources are used according to FEI's system demand throughout the year. For example, the commodity portion of gas costs is for the base load supply of gas throughout the year. The storage and transport portion of gas costs is for the purchase of seasonal gas, term gas, market area storage, upstream pipeline capacity and LNG peaking resources.

Figure 4-4: FEI Gas Supply Resources



Although there have been changes to the gas supply portfolio over the last 30 years, the gas cost allocation method remains largely consistent with what was approved in the 1991 Phase A Rate Design. FEI has maintained this cost allocation approach, which was most recently reviewed and accepted by the BCUC in the 2016 COSA Decision with one change, which is to use a three-year rolling average load factor for RS 5 for allocating midstream costs.[71]

FEI's commodity costs and storage and transport costs are allocated to sales customers. Sales customers are also referred to as the "Core Market", being those customers that purchase their commodity from either FEI directly or from marketers under the Customer Choice Program. Transportation service customers do not pay FEI's commodity or storage and transport charges.

In the following sections, FEI describes the distinction between commodity costs and storage and transport (midstream) costs as well as the allocation approaches for each.

4.4.1 Commodity

Commodity costs consist of market-priced annual baseload gas purchased by FEI and are flowed through in rates without mark-up. The Cost of Gas Charge is variable and is reviewed quarterly by the BCUC and adjusted, if required.

[71] COSA Decision, page 17.

4.4.2 Storage and Transport (Midstream)

Storage and transport costs (or midstream costs) are mainly for resources contracted by FEI to facilitate the flow of gas into FEI's service territory so that the demand of sales customers can be served and the pipeline system stays in balance on a daily basis. Storage and transport resources are used to balance FEI's entire gas distribution system by either supplementing it with gas supply when demand is greater than planned or removing excess gas supply out of the system when the demand is lower than planned. The resources that FEI has in place are to meet design day and design year conditions, and are secured in an open and competitive marketplace. The Storage and Transport Charge is reviewed by the BCUC as part of FEI's Gas Cost Report filed quarterly and typically adjusted, if required, on an annual basis.

As illustrated above in Figure 4-4, the storage and transport costs include:

- Storage contracts and transportation capacity on external pipelines that deliver gas to FEI's various interconnecting points from the market hubs and contracted gas storage facilities;
- Winter seasonal gas supply purchased by FEI that may be required to support higher than normal load requirements of core customers; and
- Allocation of costs for company-owned assets, such as the Mt. Hayes LNG facility described in Section 4.3.1.2.3 and the SCP (included as part of the transmission functions) described in Section 4.3.1.3.

Although the Storage and Transport Charge only applies to sales customers, the resources are used each day to balance the system as a whole, which benefits both sales and transportation service customers.

4.4.3 Gas Costs Allocation Approach

The current gas cost allocation methodology includes:

1. Classifying the commodity costs as energy-related and allocating those costs to sales customers based on throughput; and
2. Classifying the storage and transport costs as demand-related and allocating those costs on a load factor adjusted volumetric basis.

The storage and transport costs are allocated to sales customers using the same three-year weighted average load factor discussed in Section 4.3.3.2. This ensures that the basis of allocating the storage and transport costs is the same as the demand-related allocations for delivery costs (i.e., the peak day demand). FEI uses a rolling three-year average for the load factor to allocate storage and transport costs to each sales rate schedule in the quarterly Gas Cost Report. As noted above, the 2016 COSA Decision approved the use of the rolling three-year average load factor for General Firm Sales Service (RS 5) which is consistent with the methodology used for RS 1, 2, and 3.[72]

For Interruptible (RS 7) and Seasonal (RS 4) customers, the Storage and Transport Charge is set equal to the rate for RS 5. Interruptible and seasonal customers have a zero peak day value, as the interruptible customers would be curtailed on extreme cold weather days and the load from seasonal customers primarily occurs during the non-heating (off peak) months.

4.4.4 Gas Costs Allocation Summary

Table 4-14 below summarizes the allocation results of the gas costs. Further details of the gas costs allocation are presented in Schedule 4, Line 59 of Appendix D. FEI notes that the gas costs shown in Table 4-15 below are not re-allocated in the 2023 COSA. These costs are the gas costs directly from the 2023 Test Year as determined using the approved commodity costs related charge and storage & transportation charge at that time (these charges are set based on the allocation approach discussed in Section 4.4.3 above). FEI also notes that these gas costs are from the non-bypass rate schedules only, and exclude any gas costs related to bypass and special contract customers as well as RS 46 customers.

Table 4-15: Gas Costs Allocation to Rate Schedules (non-bypass)

Rate Schedule	($millions)	Percentage of Total
1	614.0	54.1%
2	217.3	19.2%
3/23	186.0	16.4%
4	1.1	0.1%
5/25	73.9	6.5%
6	0.1	0.0%
7/27	41.1	3.6%
22	0.1	0.0%
22A	0.3	0.0%
22B	0.3	0.0%
Total	**1,134.3**	**100.0%**

4.5 SUMMARY OF FEI'S 2023 COSA METHODS

Table 4-16 below summarizes the key components of the 2023 COSA and compares them with the methods that were used in FEI's 2016 COSA study. In general, FEI's methods for the 2023 COSA have been the same as the methods that were accepted for FEI's 2016 COSA study.[73]

[72] 2016 COSA Decision, page 17. Previously, the allocation of midstream costs to RS 5 was based on a deemed 50 percent load factor. This value was established as part of the 1996 RDA Negotiated Settlement Agreement (NSA).

[73] Accepted by Elenchus in its COSA Report (Exhibit A2-2 of 2016 RDA proceeding) and approved by the BCUC in the COSA Decision, page 11.

1 **Table 4-16: Summary of Changes to COSA Study Methods from 2016**

Application Section	Methodology Description	2016 COSA Method	2023 COSA Method	Comments
4.3.1	Functionalization	Seven Functional Categories: Gas Supply, Tilbury Storage, Mt. Hayes Storage, Distribution, Transmission, Customer Accounting and Marketing.	Eight Functional Categories. Added Tilbury 1A expansion as a separate function.	The purpose of the Tilbury 1A expansion is not the same as the Tilbury (Base Plant) LNG Storage facility and should be functionalized separately.
4.3.2	Classification	Three Cost Classifiers: Demand, Customer, and Energy.	No change from 2016.	
4.3.3	Allocation	Customer-related costs allocated based on average and weighted customers. Demand-related costs allocated to rate schedules based on coincident peak demand. Energy-related costs allocated based on sales volume.	No change from 2016 except that the costs of the Tilbury 1A expansion are classified as Energy-related and allocated based on the delivery cost of service of all non-bypass customers.	The RS 46 revenue associated with the Tilbury 1A expansion is an offsetting credit to all non-bypass customers, thus the associated costs should also be allocated to all non-bypass customers.
4.3.2.4.1	Distribution System Mains Classification	Minimum System Study was performed using 60 mm mains.	No change from 2016.	
4.3.2.4.2	Peak Load Carrying Capability	Based on capacity determination of a distribution system using 60 mm mains as the minimum.	No change from 2016.	
4.2.2.2	Revenues Associated with Bypass and Contract Rates	Revenues treated as a credit to Cost of Service and allocated to all other rate schedules.	No change from 2016.	
4.2.2.3	Biomethane Costs	The costs of the seven interconnections remaining in FEI's rate base are functionalized as distribution costs.	All costs, including the seven interconnections, are accounted for in the BVA and removed from the COSA.	The seven interconnections were approved to transfer to the BVA pursuant to Order G-165-20.
4.2.2.5	Tilbury Phase 1A Expansion	Used 10-year levelized costs and RS 46 revenue in COSA.	Standard approach using test year (2023) cost of service and RS 46 revenue in COSA.	Actual data is now available for the Tilbury 1A expansion (was in-service since 2018). It was included in the 2016 COSA as a known and measurable change.

2

4.6 REVENUE-TO-COST (R:C) AND MARGIN-TO-COST (M:C) RATIOS

The COSA study is one of the primary tools used to establish cost guidelines and to evaluate the reasonableness of the revenue of each rate schedule by determining whether the rates charged to each rate schedule adequately recover their allocated cost of service. As discussed in Section 3.5, in the 2016 COSA Decision, the BCUC determined that the R:C ratios should be used to inform rate design and rate rebalancing proposals, but also directed FEI to present both the R:C and M:C ratios for each rate schedule in the next COSA study.[74] Further, in the 2016 COSA Decision, the BCUC determined that a range of reasonableness for the R:C ratios of between 95 percent and 105 percent was appropriate for evaluating the adequacy of each rate schedule to recover their allocated cost of service.

The following section present the R:C and M:C ratios (before rebalancing) from the 2023 COSA.

4.6.1 Results – 2023 COSA R:C and M:C Ratios (Before Rebalancing)

Table 4-17 below provides the R:C ratios and M:C ratios of each rate schedule based on the results of the 2023 COSA. The R:C and M:C ratios are calculated as follows:

- R:C ratio – Calculated by dividing the sum of the delivery margin revenue (which includes the basic charge, demand charge, volumetric delivery charge, and administrative charge revenue) and the gas cost recovery revenue (which includes cost of gas and storage and transport charge) by the sum of the allocated delivery cost of service and the allocated gas costs.
- M:C ratio – Calculated by dividing the delivery margin revenue by the allocated delivery cost of service.

The results shown below represent FEI's 2023 COSA and include the known and measurable changes discussed in Section 4.2.3, but exclude any rebalancing proposals. These results help to inform FEI's rebalancing proposals, discussed in Section 5 of the Application. The final 2023 COSA results, after accounting for all rebalancing proposals, are set out in Section 5.4.1. For FEI's Transportation Service rate schedules that have companion sales rate schedules (i.e., RS 23, RS 25, and RS 27 are companions to RS 3, RS 5 and RS 7, respectively), FEI imputes a cost of gas so that, when the R:C ratios are calculated for these Transportation Service rate schedules, they are on the same basis (i.e., delivery margin plus cost of gas) as for the sales rate schedules.[75]

[74] Page 25 and Directive 5 of Order G-4-18.

[75] Order G-42-91, dated May 23, 1991, page 3. RS 23, RS 25, and RS 27 are transportation options for RS 3, 5, and RS 7 respectively. Since the allocated cost for RS 3, RS 5, and RS 7 includes cost of gas, a cost of gas is imputed for RS 23, RS 25, and RS 27 to ensure consistency and to show the R:C ratios on a combined basis for RS 3/23, RS 5/25, and RS 7/27. Without the imputed cost of gas for these transportation rate schedules, the comparison would be effectively between the M:C ratios of the transportation rate schedule and the R:C ratios of the sales rate schedule, which is not a representative comparison.

Table 4-17: R:C and M:C Ratio Results before Rebalancing[76]

Rate Schedule	R:C	M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	106.9%	126.9%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%
Rate Schedule 22A Transportation Service (Closed) Inland Service Area	101.8%	101.9%
Rate Schedule 22B Transportation Service (Closed) Columbia Service Area	100.1%	100.1%

As can be seen in the table above, all R:C ratios are within a range of 95 percent to 105 percent except for RS 5/25 and RS 22 which are 1.9 percent and 5.0 percent higher than 105 percent, respectively. This indicates the existing rates and rate designs are working well and as intended with the revenue collected mostly matching the costs caused by each rate schedule. Only a small revenue rebalancing is needed for two customer groups (i.e., approximately $3.347 million for RS 5/25 and $151 thousand for RS 22, which is approximately 0.15 percent and 0.007 percent, respectively, of FEI's total revenue at 2023 rates). The 2023 COSA results demonstrate that a comprehensive redesign of FEI's existing rates is not warranted at this time.

FEI has excluded RS 4 and RS 7/27 from Table 4-17 above because RS 4 is a seasonal service (firm in the summer and interruptible in the winter)[77] and RS 7/27 is a fully interruptible service. These rates do not drive system capacity additions, and consequently are not allocated any demand-related costs. The charges within these rate schedules are not set using their allocated costs from the 2023 COSA. Instead, the charges for these rate schedules are set based on a discount to the charges of RS 5/25, FEI's General Firm Service rate schedule. Nevertheless, FEI has calculated the ratios for these rate schedules, which are set out in Table 4-18 below.

[76] For RS 22, the R:C and M:C ratios are based only on the allocated costs against the firm revenue. As discussed in Section 4.2.3.1, RS 22 interruptible revenue is treated as a credit to the cost of service and allocated to all non-bypass customers (except RS 22) based on margin.

[77] RS 4 is winter interruptible, which is when FEI's system peaks.

Table 4-18: R:C & M:C Ratio Results for Rate Schedules Not Set Using 2023 COSA

Rate Schedule (Not Set Using Allocated Costs)	R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	338.9%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	122.4%	628.0%

4.7 COSA METHODOLOGY SUMMARY

FEI conducted the 2023 COSA in accordance with standard utility practice using the same methodologies as the 2016 COSA study, which was reviewed and approved by the BCUC in the 2016 COSA Decision, with the exception of the treatment of the Tilbury 1A expansion as discussed in Section 4.2.2.5, for the purpose of setting just and reasonable rates for the utility. FEI's 2023 COSA follows the three industry standard steps to allocate the cost of service through functionalization, classification, and allocation.

FEI has endeavoured to establish rates that will be functional for the foreseeable future. As such, in addition to costs from FEI's 2023 test year, FEI has included known and measurable changes as discussed in Section 4.2.3 for projects expected to be in-service by or soon after January 1, 2025. These projects include the IGU CPCN, the CTS-TIMC CPCN, and the GCU projects.

As set out in Section 4.6, except for RS 5/25 and RS 22, the resulting R:C ratios for all rate schedules (excluding RS 4 and RS 7/27 for the reasons discussed above) are within the range of reasonableness of 95 percent and 105 percent, which is the accepted range for R:C ratios for evaluating the adequacy of each rate schedule to recover its allocated cost of service. Given the R:C ratios of RS 5/25 and RS 22 are only 1.9 and 5.0 percent over 105 percent, respectively, and all other rate schedules are within the range of reasonableness, the 2023 COSA confirms the existing rates and rate designs are working well and as intended. Based on the 2023 COSA results, FEI concludes that a comprehensive redesign of FEI's existing rates is not warranted at this time.

Accordingly, the following sections of the Application focus on the consideration of rebalancing RS 5/25 and RS 22 only, without a comprehensive rate redesign. Please refer to Section 5 for FEI's proposals for the rebalancing of RS 5/25 and RS 22, and other considerations resulting from the rebalancing.

5. REVENUE REBALANCING PROPOSALS

As presented in Section 4.6.1, RS 5/25 and RS 22 are the only rate schedules with R:C ratios outside of the accepted range of reasonableness of 95 percent to 105 percent. Revenue rebalancing is generally the next step of a COSA study and is often used to ensure the revenue recovered from each rate schedule is reasonably aligned with the allocated cost of service by shifting revenue responsibility from one customer group to another. This section discusses the different rebalancing options available to move the R:C ratios of RS 5/25 and RS 22 back to within the range of reasonableness of 95 percent to 105 percent. It also discusses other considerations resulting from each rebalancing option and presents FEI's preferred rebalancing option as proposed in this Application.

5.1 *RATE DESIGN PRINCIPLES*

In evaluating the different rate rebalancing options, FEI applied the rate design principles identified by Dr. James C. Bonbright. FEI uses these principles to identify the issues related to each rebalancing option and to select its preferred option.

The rate design principles are the same as adopted by FEI for the 2016 RDA proceeding, which were summarized by the BCUC in the BC Hydro RIB Rate Re-Pricing Application Decision.[78] These rate design principles were also relied on in a number of recent rate design decisions by the BCUC, including the BC Hydro 2015 Rate Design Application[79] and the FortisBC Inc. (FBC) 2017 Cost of Service Analysis and Rate Design Application.[80] The rate design principles, in no particular order, are:

- Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility's total cost of service;
- Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);
- Principle 3: Price signals that encourage efficient use and discourage inefficient use;
- Principle 4: Customer understanding and acceptance;
- Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);
- Principle 6: Rate stability (customer rate impact should be managed);
- Principle 7: Revenue stability; and
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

[78] Decision and Order G-45-11, dated March 14, 2011, page 5.
[79] Decision and Order G-5-17, dated January 20, 2017, page 11-12.
[80] Decision and Order G-40-19, dated February 25, 2019, page 5.

FEI does not apply all eight principles, and also not in any priority or with any particular weighting. As will be illustrated in the section below, rate design (or revenue rebalancing in the case of this Application) is a complex balancing process as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, as different rate design principles may have varying levels of importance in different contexts, FEI applies its experience and judgement to consider and balance the most relevant principles in a given context when evaluating the different rate design (or revenue rebalancing) solutions. Rate design should strive to strike a balance among competing rate design principles based on the specific characteristics of customers in each rate schedule.

5.2 *REVENUE REBALANCING CONSIDERATIONS*

As discussed above, the results of the 2023 COSA show that only RS 5/25 and RS 22 have R:C ratios above the range of reasonableness of 95 percent to 105 percent. To rebalance RS 5/25 and RS 22 within the range of reasonableness, some revenue responsibility from RS 5/25 and RS 22 must be shifted to other rate schedules. This is typically done by using the rate schedules currently with R:C ratios below 100 percent, but above the lower bound range of reasonableness of 95 percent. As shown in Table 4-17 in Section 4.6.1, there are currently three rate schedules with R:C ratios less than 100 percent (RS 1, RS 2, and RS 6) which could be used to bring RS 5/25 and RS 22 back within the range of reasonableness.

In the following subsections, FEI explains the factors it considered when developing the revenue rebalancing options described in Section 5.3. These factors and considerations underpin the development of the rebalancing options and, in conjunction with the assessment of the options against the rate design principles outlined in Section 5.1 above, inform FEI's proposed approach to rebalancing, which is presented in Section 5.4 below.

5.2.1 Rebalancing Using Residential (RS 1) or Small Commercial (RS 2) Customers

As discussed above, the 2023 COSA shows that there are currently three rate schedules with an R:C ratio below 100 percent which, in theory, can be used to rebalance RS 5/25 and RS 22. These three rate schedules are Residential (RS 1), Small Commercial (RS 2), and Natural Gas Vehicle (RS 6). However, only RS 1 and RS 2 are the logical and suitable choices for rebalancing as it would not be effective or meaningful to use RS 6 for revenue shifts from RS 5/25 and RS 22.

This is because for RS 6, the current revenue and costs in the 2023 COSA are approximately $210.9 thousand and $219.2 thousand, respectively.[81] Therefore, RS 6 can only absorb a maximum of approximately $8.3 thousand from either RS 5/25 or RS 22, which would increase the R:C ratio of RS 6 to 100 percent. Considering the total revenue shift required from RS 5/25 and RS 22 is approximately $3.495 million ($3.344 million for RS 5/25 and $151 thousand for

[81] Revenue of $210.9 thousand divided by Cost of $219.2 thousand equals an R:C ratio of 96.2 percent for RS 6 as shown in Table 4-17.

RS 22), changing the rates of RS 6 to only absorb $8.3 thousand, which is approximately 0.24 percent of the total revenue shift required, would be ineffective.

In contrast, RS 1 and RS 2 are the two customer groups with the greatest revenue and most capability to absorb a revenue shift from RS 5/25 and RS 22. For example, RS 1 currently has an R:C ratio of 97.3 percent and can absorb a maximum of approximately $34.7 million of a revenue shift until it reaches an R:C ratio of 100 percent. Similarly, RS 2 currently has an R:C ratio of 98.0 percent and can absorb a maximum of approximately $7.8 million of a revenue shift until it reaches an R:C ratio of 100 percent. As such, FEI considers it would be most reasonable and appropriate to shift some revenue from RS 5/25 and 22 to RS 1 or RS 2 to bring the R:C ratios of RS 5/25 and 22 back to 105 percent. FEI will discuss and compare the rebalancing options in Section 5.3 below.

5.2.2 Implications of Rebalancing RS 2 on the Economic Crossover between RS 2 and RS 3/23 Customers

As discussed in the previous section, RS 2 is one of the two rate schedules that would be suitable for rebalancing and absorbing the revenue shift from RS 5/25 and RS 22. However, increasing the rates (basic and/or variable charges) of RS 2 would change the economic crossover point between the RS 2 customer group and RS 3/23 customer group, which is the annual volume at which point a customer would have the same annual total cost whether served under RS 2 or RS 3/23.

Table 5-1 below shows that the current economic crossover volume between RS 2 and RS 3/23 at the 2023 Approved rates is approximately 1,515 GJ per year, which is already below the segmentation volume threshold of 2,000 GJ per year that is set out in the tariffs for these two customer groups. This deviation occurs because the Basic Charges for both RS 2 and RS 3/23 remain constant over time while the variable delivery charges are subject to change each year from FEI's rate-setting proceedings (annual reviews during FEI's current 2020-2024 MRP or revenue requirement applications). Therefore, it is mathematically certain that the economic crossover point between RS 2 and RS 3/23 will deviate over time from the segmentation threshold of 2,000 GJ per year. This means that, at the current rates, a customer who consumes more than 1,515 GJ per year but less than 2,000 GJ per year is better off financially being served as a customer under RS 3/23. However, if the rates (basic and/or variable charges) of RS 2 are increased to absorb the revenue shift from RS 5/25 and RS 22, it will cause the economic crossover volume between RS 2 and RS 3/23 to decrease and deviate further from the designed segmentation threshold of 2,000 GJ. Therefore, if RS 2 is used for rebalancing RS 5/25 and RS 22, it will also be necessary to consider the resulting impact on the economic crossover point between RS 2 and RS 3/23, and whether the rates of RS 3/23 will also need to be changed to address this resulting impact.

Table 5-1: Current (2023 Approved Rates) Economic Crossover Volume between RS 2 and RS 3/23

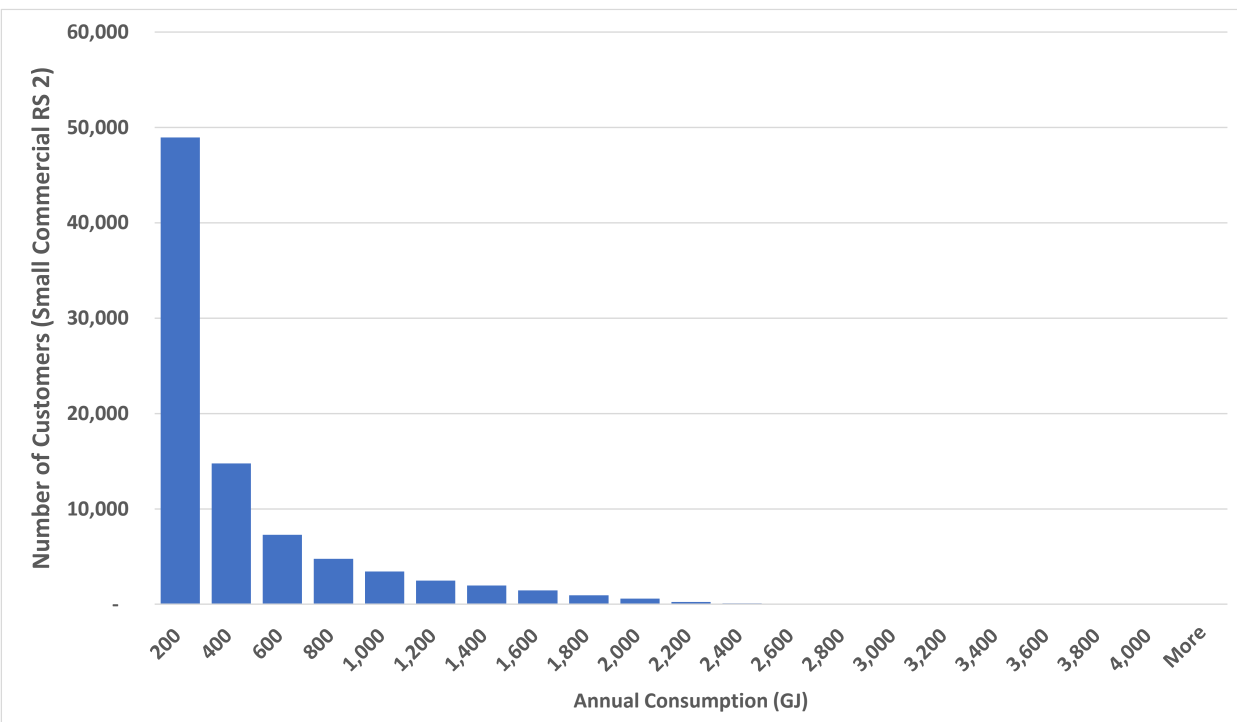
Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		0.9485	4.7895	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	346	1,749	1,403
4					
5	Delivery Charge ($/GJ)		4.568	3.893	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.318	10.392	0.926
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	1,515	1,515	1,515

The following subsections demonstrate that the current segmentation threshold of 2,000 GJ per year remains reasonable. Therefore, if RS 2 is included as part of the revenue rebalancing for RS 5/25 and RS 22, then consideration should be given to ensuring the economic crossover point between RS 2 and RS 3/23 is closely aligned with the segmentation threshold of 2,000 GJ per year.

5.2.2.1 RS 2 and RS 3/23 Bill Frequency

Figures 5-1 and 5-2 below show the volume frequency for the normalized actual annual consumption from 2022 (the most recent full year of actual data available at the time of this Application) for RS 2 and RS 3/23 customers, respectively.

Figure 5-1: Small Commercial (RS 2) Customer Annual Volume Frequency



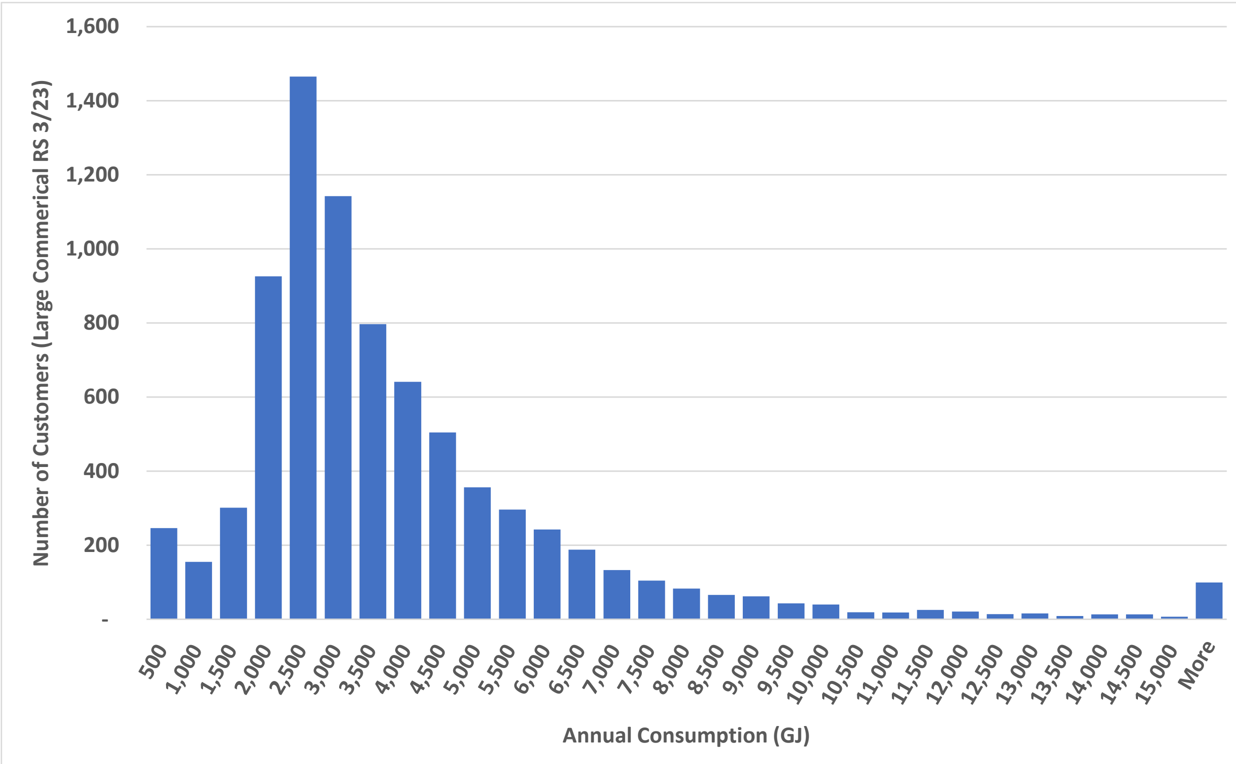
As shown in Figure 5-1 above, approximately 87,000 (or 99 percent) of RS 2 customers consumed less than 2,000 GJ in 2022 while only approximately 625 customers consumed more than the 2,000 GJ threshold. Many of the RS 2 customers consuming more than the 2,000 GJ threshold in 2022 are either new customers whose annual consumption estimates, prior to connecting to FEI's system, were too low, or they are customers who have had a material change to their business operations during the year.

For RS 3/23 customers, Figure 5-2 below shows that the majority consumed more than 2,000 GJ in 2022, with approximately 1,600 (or 20 percent) consuming less than 2,000 GJ in 2022. Many of these customers likely have reduced their operations during the year, have implemented energy efficiency measures, had business ownership changes, or only had a partial year of operations.

Based on the bill frequency of RS 2 and RS 3/23, the segmentation threshold of 2,000 GJ remains reasonable as almost all commercial customers (approximately 98 percent[82]) are correctly placed in either RS 2 or RS 3/23 in terms of the volume threshold of 2,000 GJ. It is FEI's practice to review the consumption history of RS 2 and RS 3/23 customers annually to ensure that commercial customers are served under the appropriate rate schedule based on their consumption meeting the tariff requirements. Based on this annual consumption review, FEI will transfer commercial customers to the appropriate rate schedule (between RS 2 and RS 3/23) as necessary.

[82] Number of RS 2 customers less than 2,000 GJ in 2022 is approximately 87,000, number of RS 3/23 customers above 2,000 GJ in 2022 is approximately 6,400. Total number of commercial (RS 2, 3, 23) customers in 2022 is 95,300, therefore, (87,000 + 6,400) / 95,300 = 98 percent.

Figure 5-2: Large Commercial (RS 3/23) Customer Annual Volume Frequency



5.2.2.2 Load Factor

Figures 5-3 and 5-4 below show the load factors, calculated using the methodology described in Section 4.3.3.2, for RS 2 and RS 3/23 customers in 2022. The figures show that there is a clear distinction between RS 2 and RS 3/23 customers. The load factor of most RS 2 customers is between 20 percent and 30 percent[83] while the load factor of most RS 3/23 customers is between 30 percent and 50 percent.[84] This supports the continuation of segmenting the commercial customers into the two customer groups.

[83] Approximately 67 percent of all RS 2 customers.
[84] Approximately 62 percent of all RS 3/23 customers.

Figure 5-3: Small Commercial (RS 2) Customer Load Factor Distribution

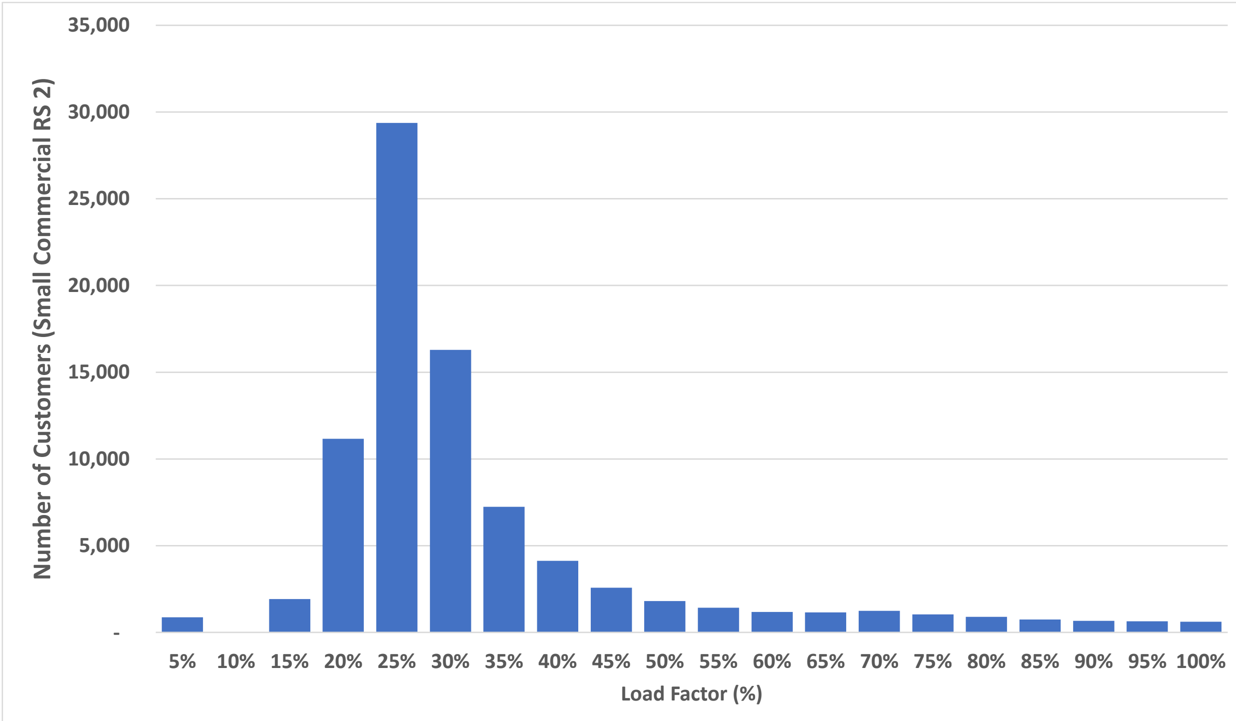


Figure 5-4: Large Commercial (RS 3/23) Customer Load Factor Distribution

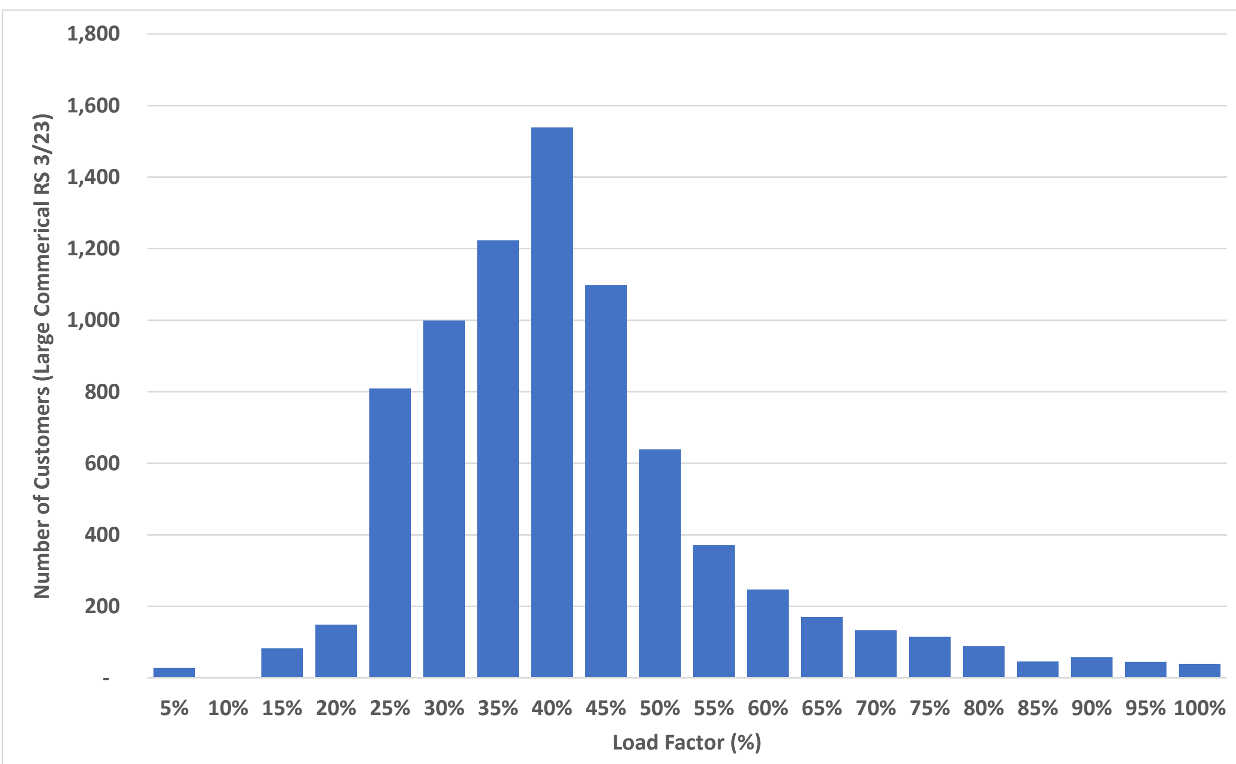
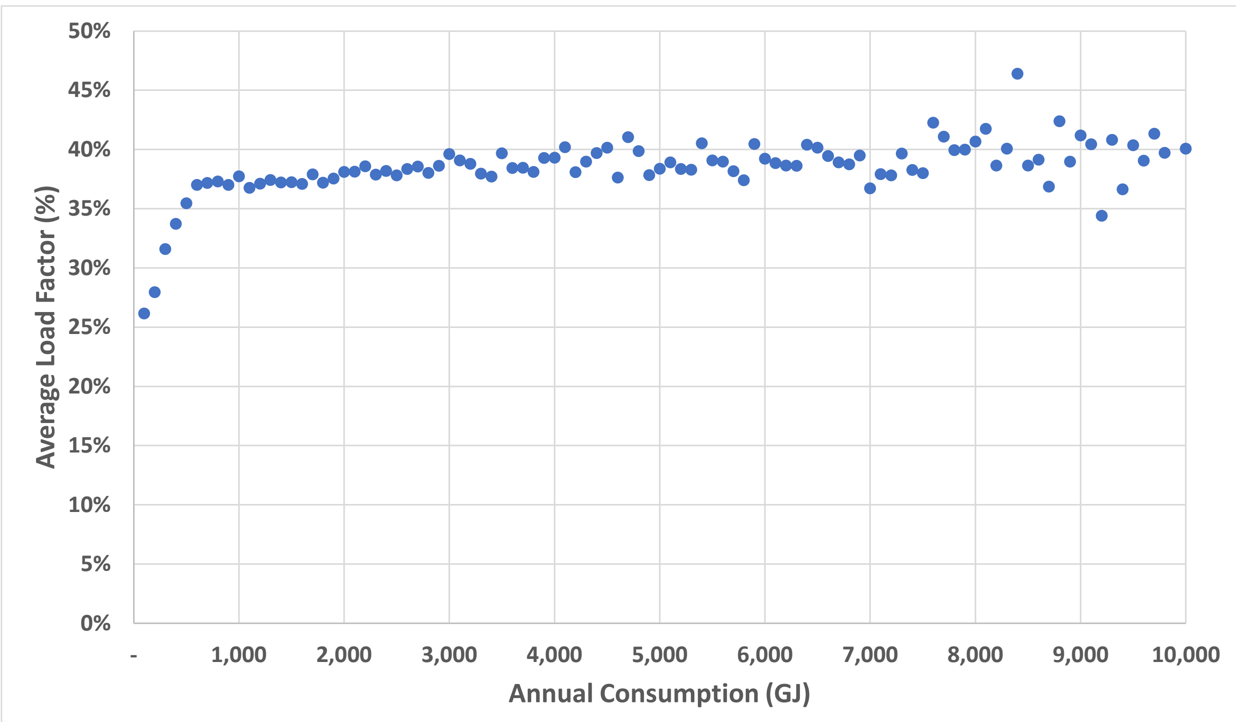


Figure 5-5 below provides the annual consumption of commercial customers in relation to their average load factor. This figure shows that the load factor of commercial customers starts at about 25 percent at around 500 GJ per year, then increases to about 38 percent at 1,000 GJ per year, which is mostly related to Small Commercial customers. From about 1,000 GJ onward, which is mostly Large Commercial customers, the load factor increases slightly to near 40 percent, and at 2,000 GJ per year and above, the load factor is relatively consistent at 40 percent. This trend is consistent with the load factor of commercial customers versus annual consumption in FEI's 2016 RDA.[85] As such, the data continues to support the segmentation of commercial customers into the two customer groups.

Figure 5-5: Average Commercial Customer (RS 2 and RS 3/23) Load Factor versus Annual Consumption Levels



Given the distinct load factor differences between the Small Commercial and Large Commercial customers, the current threshold of 2,000 GJ remains reasonable and should continue to be used as the economic crossover point between RS 2 and RS 3/23 customer groups. While differences can also be found at other threshold levels, the threshold and the relationship between load factor and consumption would need to be significantly different than 2,000 GJ as well as the trend shown in Figure 5-5 above to support moving away from the existing threshold of 2,000 GJ.

[85] Exhibit B-1-5 of the 2016 RDA Proceeding, Figure 8-10, pp. 9-10.

5.2.3 Implications of Rebalancing RS 5/25 on the Economic Crossover between RS 3/23 and RS 5/25 Customers

As the R:C ratio for RS 5/25 is currently above the upper range of reasonableness of 105 percent, RS 5/25 could be rebalanced and, as discussed in Section 5.2.2 above, there is also a possible adjustment to RS 3/23 to address the economic crossover point between RS 2 and RS 3/23. Both of these adjustments could impact the economic crossover point between RS 3/23 and RS 5/25.

RS 5/25 is designed for customers with relatively higher load factors of 40 percent or above, as reflected by the fact that RS 5/25 includes a demand charge, which means customers with higher load factors have a smaller average bill than those with lower load factors for the same annual volume consumption. Customers with load factors lower than 40 percent generally would be taking service under RS 3/23 where the average load factor is approximately 36 percent.

Figure 5-6 below provides the load factors for RS 5/25 customers using 2022 normalized actual consumption data. It can be seen that RS 5/25 generally captures the intended customer group (customers with higher load factors of 40 percent or above) with the majority of RS 5/25 customers with load factors of 55 to 65 percent. Therefore, to ensure the rates for RS 5/25 are achieving their purpose, it is important to consider, as part of evaluating the different revenue rebalancing options, whether FEI should adjust rates so that it is economical for customers whose load factor is less than 40 percent to take service under RS 3/23, rather than RS 5/25.

Figure 5-6: General Firm Service (RS 5/25) Customer Load Factor Distribution

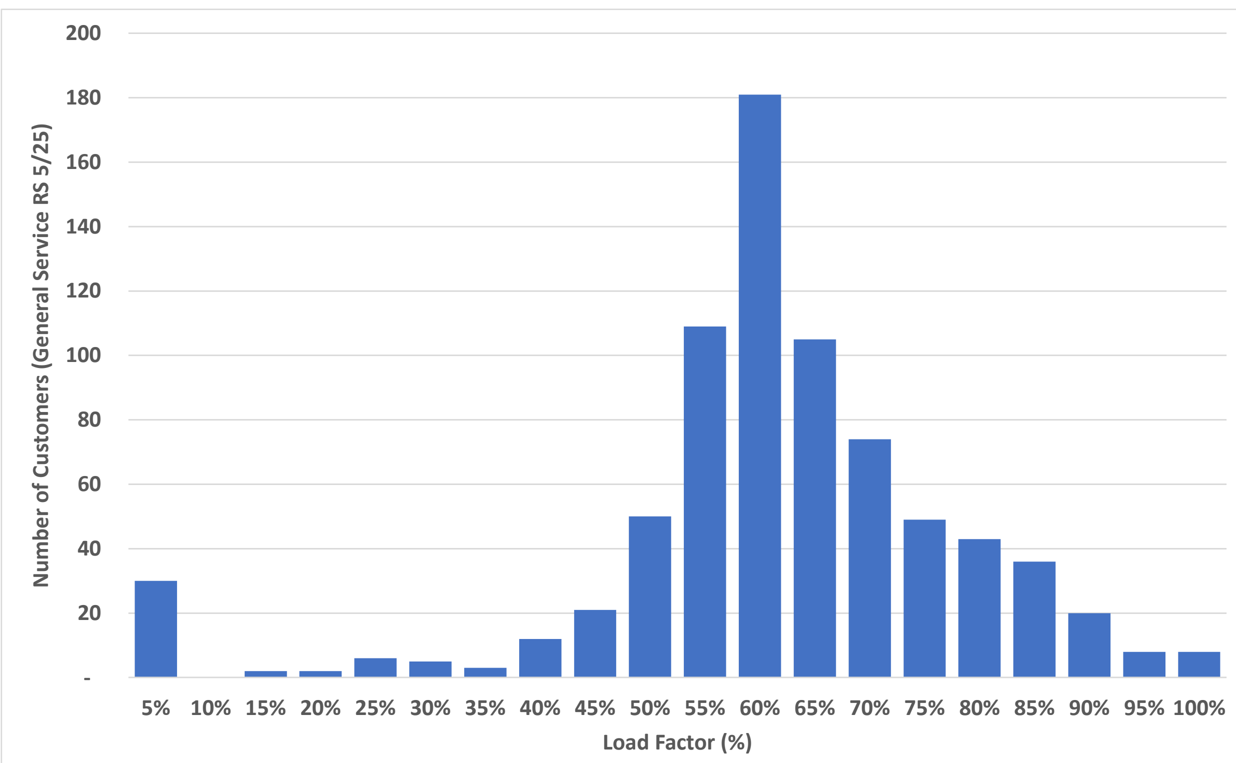


Table 5-2 below provides the economic crossover volumes for load factors less than 50 percent, where a customer would have the same annual bill whether taking service under RS 3/23 or RS 5/25, based on the rates at the time of implementing the 2016 RDA Decision and the current 2023 Approved rates. If a customer's volume for a given load factor is greater than the economic crossover volume shown in the table below, then the customer would receive a lower annual bill under RS 5/25 than under RS 3/23. FEI notes that the 50 percent is chosen because, as shown in Figure 5-4 above, the load factors for the majority of RS 3/23 customers are between 30 percent and 50 percent. Further, Table 5-2 stops at 37 percent at the lower bound because, under the rates at the time of the 2016 RDA Decision and also at the current 2023 Approved rates, there is no volume at load factors from 36 percent or below that would result in RS 5/25 being more economical than RS 3/23.

Table 5-2: Economic Crossover at Varying Load Factors for Large Commercial (RS 3/23) and General Firm Service (RS 5/25) at 2016 RDA Decision and 2023 Approved Rates

		2016 RDA Decision			Current 2023 Approved Rates	
		RS 3/23	RS 5/25		RS 3/23	RS 5/25
Monthly Charge, Basic + Admin ($/Mth)		185	508		185	508
Demand Charge ($/GJ/Mth)			24.596			30.278
Delivery Charge ($/GJ)		3.190	0.887		3.893	1.085
Load Factor	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume
50%	5,656	31	845	4,747	26	709
45%	7,665	47	1,273	6,509	40	1,081
40%	13,783	94	2,575	12,144	83	2,268
39%	16,895	119	3,237	15,175	107	2,907
38%	22,162	160	4,358	20,585	148	4,048
37%	33,010	244	6,666	32,976	244	6,659

FEI's analysis demonstrates that the economic crossover volumes have remained similar when comparing the rates at the time of implementing the 2016 RDA Decision and the current 2023 Approved rates. As such, when evaluating the different revenue rebalancing options presented in Section 5.3 below, one of the considerations is the impact to the economic crossover point between RS 3/23 and RS 5/25 due to rebalancing, and to what extent the economic crossover point at various load factors would deviate from the level at the current 2023 Approved rates.

5.3 REVENUE REBALANCING OPTIONS

This section discusses the different revenue rebalancing options which FEI developed based on the results of the 2023 COSA as well as to address the considerations discussed in Section 5.2 above. FEI assesses each revenue rebalancing option against Bonbright's rate design principles and identifies the preferred rebalancing option.

5.3.1 Option 1: Status Quo

Under the Status Quo, no rebalancing would occur, resulting in RS 22 and RS 5/25 remaining above the range of reasonableness of 105 percent, (i.e., RS 22 at 110.0 percent and RS 5/25 at 106.9 percent). FEI considered this option because the impact of not rebalancing is relatively small for RS 22 and RS 5/25 customers. RS 22 is approximately 5.0 percent above 105 percent, which is equivalent to approximately $151 thousand or 4.5 percent of the revenue collected from RS 22 customers. RS 5/25 is approximately two percent above 105 percent, which is equivalent to approximately $3.344 million or 1.8 percent of the revenue collected from RS 5/25 customers.

When assessed against the Bonbright rate design principles, Option 1 does not align with principle 2:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  Although the gaps between the R:C ratios of the two rate schedules and 105 percent are relatively small, without rebalancing, the R:C ratios of RS 22 and RS 5/25 will remain above the range of reasonableness. In other words, the cost recovery through existing rates does not reflect the fair appointment of costs from RS 22 and RS 5/25 based on the current acceptable range of reasonableness of 95 percent to 105 percent.

5.3.2 Option 2: Revenue Rebalancing without Adjustment for Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25

Option 2 involves revenue rebalancing only to ensure all R:C ratios are within the range of reasonableness of 95 percent and 105 percent, but does not include any adjustments regarding the economic crossover point between RS 2 and RS 3/23 or between RS 3/23 and RS 5/25. There are two possible options to absorb the revenue shifts from RS 22 and RS 5/25: (1) use RS 1; or (2) use RS 2. These options are discussed below as Option 2a and Option 2b, respectively.

5.3.2.1 Option 2a: Revenue Rebalancing Only Using RS 1

Option 2a uses only Residential RS 1 to absorb the revenue shifts from RS 22 and RS 5/25. Table 5-3 below provides the initial 2023 COSA results (as presented in Table 4-17) before any rebalancing, the revenue shifts for rebalancing under this Option 2a, the approximate bill impacts, and the final 2023 COSA results after the revenue shifts.

As previously explained, the Seasonal (RS 4) and General Interruptible Service (RS 7/27) rates are set at a discount to RS 5/25 rates,[86] therefore, rebalancing RS 5/25 would result in a

[86] For RS 4, the Off-Peak period delivery charge is derived from the RS 5 demand charge converted to a volumetric rate at 100 percent load factor, plus the RS 5/25 delivery charge. From November 1 to March 31 (referred to as the Extension Period), customers under RS 4 are fully interruptible and the delivery charge is set based on the delivery charge of RS 7/27 times 1.5. For RS 7/27, as approved by the BCUC in the 2016 RDA Decision (pages 21 to 24), the existing delivery charges with a load factor of 62.5 percent are based on a discount of approximately 18 percent as compared to RS 5/25 (General Firm Service) customers with a load factor of 90.9 percent.

commensurate reduction to RS 4 and RS 7/27 in order to maintain their current discount to RS 5/25.

Table 5-3: Option 2a – 2023 COSA R:C and M:C Results after Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	4,519	0.4%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	-	-	98.0%	95.6%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	-	-	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Under Option 2a, RS 1 customers will have a relatively small bill impact of 0.4 percent. For the average RS 1 customer with 90 GJ of consumption annually, the average annual bill impact is approximately $4.95. Table 5-4 below summarizes the rate changes to RS 1, RS 4, RS 5/25, RS 7/27, and RS 22 under Option 2a.

Table 5-4: Summary of Rate Changes under Option 2a

Rate Schedule	Current 2023 Approved Rates	Changes	Option 2a
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.055	$ 6.065
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, Option 2a aligns with principle 2 by bringing the R:C ratios within the range of reasonableness:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules would fall within the range of reasonableness of 95 percent to 105 percent. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

However, Option 2a does not fully align with principles 3 and 6:

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use</u>**

  Since there are no adjustments to either RS 2 or RS 3/23 under Option 2a, the economic crossover point between RS 2 and RS 3/23 remains at approximately 1,515 GJ per year as discussed in Section 5.2.2 and shown in Table 5-1. This misalignment between the volume threshold of 2,000 GJ and the current economic crossover of 1,515 GJ is sending an incorrect price signal to commercial customers that have an annual volume between 1,515 GJ and 2,000 GJ. Based on 2022 actual annual consumption, approximately 3,025 customers under RS 2 and RS 3/23 are within this range. Furthermore, as noted in Section 5.2.2, since the Basic Charges of RS 2 and RS 3/23 remain constant over time, this misalignment between the volume threshold and the economic crossover point of RS 2 and RS 3/23 will continue to increase.

Additionally, since the rates of RS 5/25 are reduced due to revenue rebalancing, but there is no corresponding adjustment made to the rates of RS 3/23, the economic crossover point between RS 3/23 and RS 5/25 will be reduced, as shown in Table 5-5 below. This would lead to an increased number of customers currently under RS 3/23 that could receive a lower annual bill if they are taking service under RS 5/25, therefore sending an incorrect price signal to these customers. Based on the actual 2022 annual consumption, FEI estimates that, when compared to the current 2023 Approved rates, approximately 739 additional RS 3/23 customers could be receiving a lower annual bill if they took service under RS 5/25 with Option 2a. Although the economic crossover point between RS 3/23 and RS 5/25 would send an incorrect price signal to some customers taking service under these rate schedules, FEI expects switching between rate schedules would naturally occur over time regardless of the economic crossover point, and the number of customers impacted is limited. The 737 additional RS 3/23 customers represent about 0.07 percent of FEI's number of customers (2023 Approved), and if all customers that could receive a lower bill under RS 5/25 switch at the same time, the impact would be a reduction in total FEI revenue of approximately $2.7 million, which is approximately 0.12 percent when compared to FEI's 2023 Approved revenue requirement of $2.249 billion. FEI notes any reduction in revenue due to customers switching between rate schedules would be recovered through the delivery rates from all non-bypass customers in the next rate-setting proceeding, all else equal.

Table 5-5: Economic Crossover at Varying Load Factors for Large Commercial (RS 3/23) and General Firm Service (RS 5/25) at Current 2023 Approved Rates and Option 2a

		Current 2023 Approved Rates			Option 2a	
		RS 3/23	RS 5/25		RS 3/23	RS 5/25
Monthly Charge, Basic + Admin ($/Mth)		185	508		185	508
Demand Charge ($/GJ/Mth)			30.278			28.289
Delivery Charge ($/GJ)		3.893	1.085		3.893	1.014
Load Factor	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume
50%	4,747	26	709	3,807	21	569
45%	6,509	40	1,081	4,775	29	793
40%	12,144	83	2,268	7,003	48	1,308
39%	15,175	107	2,907	7,847	55	1,503
38%	20,585	148	4,048	8,989	65	1,767
37%	32,976	244	6,659	10,616	79	2,144

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**

As shown in Table 5-4, Option 2a will result in a bill impact to RS 1 customers. However, the impact is relatively minor at approximately 0.4 percent or the equivalent of $4.95 annually. The RS 1 R:C ratio will remain at less than 100 percent and will continue to be within the range of reasonableness, even after absorbing the revenue shift from RS 22 and RS 5/25.

5.3.2.2 Option 2b: Revenue Rebalancing Only Using RS 2

Option 2b uses only RS 2 to absorb the revenue shifts from RS 22 and RS 5/25. Table 5-6 below provides the initial 2023 COSA results (as presented in Table 4-17) before any rebalancing, the revenue shifts for rebalancing under Option 2b, the approximate bill impacts, and the final 2023 COSA results after the revenue shifts. Option 2b includes adjustments to RS 4 and RS 7/27 to maintain their current discount from RS 5/25 (since the RS 5/25 rates are reduced due to rebalancing as explained in Section 5.3.2.1).

Table 5-6: Option 2b – 2023 COSA R:C and M:C Results after Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	-	-	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	4,519	1.2%	99.2%	98.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	-	-	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Table 5-7 below summarizes the resulting changes to RS 2, RS 4, RS 5/25, RS 7/27, and RS 22 under Option 2b. There is no impact to RS 1 customers due to revenue rebalancing under Option 2b. Instead, RS 2 customers will experience a bill impact of approximately 1.2 percent, which results in an annual bill impact of approximately $49.83 for the average RS 2 customer with 322 GJ of consumption annually.

Table 5-7: Summary of Rate Changes under Option 2a

Rate Schedule	Current 2023 Approved Rates	Changes	Option 2b
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ -	$ 0.9485
Delivery Charge ($/GJ)	$ 4.568	$ 0.1547	$ 4.723
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, Option 2b aligns with principle 2 by bringing the R:C ratios within the range of reasonableness:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules will fall within the range of reasonableness of 95 percent to 105 percent. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

However, Option 2b does not fully align with principles 3 and 6:

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use</u>**

  Since the rebalancing involves increasing the rates of RS 2 to absorb the revenue shift from RS 22 and RS 5/25, it will impact the economic crossover point between RS 2 and RS 3/23 given that the rates of RS 3/23 remain unchanged. Table 5-8 below shows that increasing the rates of RS 2 for rebalancing purposes will reduce the economic crossover volume between RS 2 and RS 3/23 to approximately 1,298 GJ per year (from 1,515 GJ per year under 2023 Approved rates) which is approximately 702 GJ less than the segmentation threshold of 2,000 GJ. As such, Option 2b exacerbates the incorrect price signal that exists under the current rates by increasing the misalignment between the volume threshold of 2,000 GJ and the economic crossover point. FEI estimates that, based on 2022 actual annual consumption, approximately 5,081 customers in RS 2 and RS 3/23 would fall between the economic crossover point of 1,298 GJ and the segmentation threshold of 2,000 GJ under Option 2b, compared to approximately 3,025 customers under Option 2a. In other words, there would be more customers in RS 2 under Option 2b than Option 2a that could receive a lower bill if they moved to RS 3/23 since their consumption is higher than the economic crossover point but below the volume threshold of 2,000 GJ.

Table 5-8: Economic Crossover Volume between RS 2 and RS 3/23 under Option 2b

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		0.9485	4.7895	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	346	1,749	1,403
4					
5	Delivery Charge ($/GJ)		4.723	3.893	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.473	10.392	1.081
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	1,298	1,298	1,298

Additionally, given that the rates of RS 3/23 remain unchanged while RS 5/25 are rebalanced to 105 percent, the impact to the economic crossover point between RS 3/23 and RS 5/25 would be the same as Option 2a, which is sending an incorrect price signal to customers. FEI estimates that, when compared to current 2023 Approved rates, approximately 739 additional RS 3/23 customers could receive a lower annual bill under RS 5/25, which is a reduction in total FEI revenue of approximately $2.7 million if all customers that could receive a lower bill under RS 5/25 switch at the same time. Although the economic crossover point between RS 3/23 and RS 5/25 would send an incorrect price signal to some customers taking service under these rate schedules, the number of customers impacted is limited. The 737 additional RS 3/23 customers represent about 0.07 percent of FEI's number of customers (2023 Approved), and if all customers that could receive a lower bill under RS 5/25 switch at the same time, the impact would be a reduction in total FEI revenue of approximately $2.7 million, which is approximately 0.12 percent when compared to FEI's 2023 Approved revenue requirement of $2.249 billion. Any reduction in revenue under this option due to customers switching between rate schedules would be recovered through the delivery rates of all non-bypass customers in the next rate-setting proceeding, all else equal.

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**

  As shown in Table 5-4, Option 2b will have a bill impact on RS 2 customers. However, the impact is relatively minor at approximately 1.2 percent or $49.83 annually. The RS 2 R:C ratio will remain less than 100 percent and will continue to be within the range of reasonableness after absorbing the revenue shift from RS 22 and RS 5/25.

5.3.3 Option 3: Revenue Rebalancing Using RS 1 plus Adjustments to RS 2 and RS 3/23 for Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25

Under Option 3, RS 1 is used to absorb the revenue shifts from RS 5/25 and RS 22, and RS 2 and RS 3/23 are adjusted to maintain the current economic crossover points between RS 2 and RS 3/23, and RS 3/23 and RS 5/25.

Table 5-9 below provides the initial 2023 COSA results (as presented in Table 4-17) before any rebalancing, the revenue shifts for rebalancing under Option 3, the approximate bill impacts, and the final 2023 COSA results after the revenue shifts. As with Option 2, Option 3 includes adjustments to RS 4 and RS 7/27 to maintain their current discount from RS 5/25 (since the RS 5/25 rates are reduced due to rebalancing as explained in Section 5.3.2.1).

Table 5-9: Option 3 – 2023 COSA R:C and M:C Results after Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	4,519	0.4%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	4,071	1.1%	99.1%	97.9%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(4,071)	(1.2%)	102.8%	107.7%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Table 5-10 below summarizes the changes to RS 1, RS 2, RS 3/23, RS 4, RS 5/25, RS 7/27, and RS 22 under Option 3. The impact to RS 1 customers is relatively small at 0.4 percent which, for the average RS 1 customer with 90 GJ of consumption annually, results in an annual bill impact of approximately $4.95. The bill impact for RS 2 customers is approximately 1.1 percent, which results in an annual bill impact of approximately $44.98 for the average RS 2 customer with 322 GJ of consumption annually.

Table 5-10: Summary of Rate Changes under Option 3

Rate Schedule	Current 2023 Approved Rates	Changes	Option 3
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.055	$ 6.065
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.3555	$ 1.3040
Delivery Charge ($/GJ)	$ 4.568	$ (0.264)	$ 4.304
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 1.8639	$ 6.6534
Delivery Charge ($/GJ)	$ 3.893	$ (0.315)	$ 3.578
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, Option 3 aligns with principle 2 by bringing the R:C ratios within the range of reasonableness, and partially improves the alignment with principles 3 and 6 compared to Options 2a and 2b:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules would be within the range of reasonableness. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use (Partially)</u>**

  Under Option 3, the rates of RS 2 and RS 3/23 are adjusted to maintain the economic crossover points between RS 2 and RS 3/23 (as discussed in Section 5.2.2) and RS 3/23 and RS 5/25 (as discussed in Section 5.2.3). Table 5-11 below confirms that, under Option 3, the increase in the Basic Charge for both RS 2 and RS 3/23, plus the offset from the reduction of the variable delivery rates, will move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. Additionally, as shown in Table 5-12 below, the adjusted rates ensure the economic crossover point between RS 3/23 and RS 5/25 is maintained at a level similar to the current 2023 Approved rates.

However, Option 3 represents only a partial improvement compared to Options 2a and 2b. As shown in Tables 5-11 and 5-12 below, the implications of maintaining the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 are that the Basic Charges of RS 2 and RS 3/23 would have to be increased substantially from the current level. As shown in Table 5-10 above, under Option 3, the Basic Charge for RS 2 will have to be increased from $0.9485 per day to $1.3040 per day (an increase of approximately $130 per year) while the Basic Charge for RS 3/23 will have to be increased from $4.7895 per day to $6.6534 per day (an increase of approximately $680 per year). Since the potion of fixed charge is increased while the portion of variable charge is reduced under Option 3, the price signal for efficient use would be reduced, resulting in a misalignment with this rate design principle.

Table 5-11: Economic Crossover Volume between RS 2 and RS 3/23 under Option 3

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.3040	6.6534	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	476	2,430	1,954
4					
5	Delivery Charge ($/GJ)		4.304	3.578	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.054	10.077	0.977
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

Table 5-12: Economic Crossover at Varying Load Factors for Large Commercial (RS 3/23) and General Firm Service (RS 5/25) at Current 2023 Approved Rates and Option 3

		Current 2023 Approved Rates			Option 3	
		RS 3/23	RS 5/25		RS 3/23	RS 5/25
Monthly Charge, Basic + Admin ($/Mth)		185	508		242	508
Demand Charge ($/GJ/Mth)			30.278			28.289
Delivery Charge ($/GJ)		3.893	1.085		3.578	1.014
Load Factor	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume
50%	4,747	26	709	4,543	25	679
45%	6,509	40	1,081	6,431	39	1,068
40%	12,144	83	2,268	13,387	92	2,501
39%	15,175	107	2,907	17,839	125	3,418
38%	20,585	148	4,048	27,449	198	5,397
37%	32,976	244	6,659	63,508	470	12,825

Further, Option 3 would not fully align with principles 4 and 6:

- **Principle 4 – Customer understanding and acceptance**

  Basic charges usually remain constant during FEI's annal rate changes. Therefore, if the Basic Charges of RS 2 and RS 3/23 are increased under Option 3 due to revenue rebalancing, it might lead to customer confusion and could impact customer acceptance (especially for small and large commercial customers).

- **Principle 6 – Rate stability (Customer rate impact should be managed)**

  The average bill impacts for RS 1 and RS 2 customers are relatively minor under Option 3, that is, 0.4 percent or $4.95 per year for the average RS 1 customer and 1.1 percent or $44.98 per year for the average RS 2 customer. However, the increase in Basic Charges for RS 2 and RS 3/23 will have the biggest impact on commercial customers with small or minimal volume since these customers would have limited opportunity to offset the increased Basic Charges through the decrease in variable charges which is shown in Table 5-10 above for both RS 2 and RS 3/23 under Option 3. For example, assuming a particular commercial customer has no volumes (which could occur over time when a commercial property is under development/renovation, changing ownership/lease, or vacant) and pays for the Basic Charge only, they will experience the maximum bill impact of $130 per year under RS 2 or $680 per year under RS 3/23, since this customer would not be able to offset the increase through the reduced variable charges. In short, the bill impact to commercial customers with small or minimal volumes does not align with the rate design principle of rate stability.

5.3.4 Option 4: Revenue Rebalancing Using RS 2 plus Adjustments to RS 2 and RS 3/23 for Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25

Under Option 4, RS 2 is used to absorb the revenue shifts from RS 5/25 and RS 22 and is also used to adjust the economic crossover between RS 2 and RS 3/23 back to 2,000 GJ per year. Under this option, the rates of RS 3/23 are also adjusted to maintain the economic crossover point between RS 3/23 and RS 5/25.

Table 5-13 below provides the initial 2023 COSA results (as presented in Table 4-17) before any rebalancing, the revenue shifts for rebalancing, the approximate bill impacts, and the final 2023 COSA results after the revenue shifts. As with Options 2 and 3, Option 4 includes adjustments to RS 4 and RS 7/27 to maintain their current discount from RS 5/25 (since the rates RS 5/25 rates are reduced due to rebalancing as explained in Section 5.3.2.2).

Table 5-13: Option 4 – 2023 COSA R:C and M:C Results after Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	-	-	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	4,075	1.1%	99.1%	97.9%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	444	0.1%	104.1%	111.5%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Table 5-14 below summarizes the rate changes to RS 2, RS 3/23, RS 4, RS 5/25, RS 7/27, and RS 22 under Option 4. Under this option, there will be no impact to RS 1 customers. The bill impact for RS 2 customers will be approximately 1.1 percent which, for the average RS 2 customer with 322 GJ of consumption annually, results in an annual bill impact of approximately $44.93. For RS 3/23 customers, the bill impact will be approximately 0.1 percent which, for the average RS 3/23 customer with 3,650 GJ of consumption annually, results in an annual bill impact of approximately $123.10.

Table 5-14: Summary of Rate Changes under Option 4

Rate Schedule	Current 2023 Approved Rates	Changes	Option 4
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ -	$ 0.9485
Delivery Charge ($/GJ)	$ 4.568	$ 0.1395	$ 4.708
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 4.0145	$ 8.8040
Delivery Charge ($/GJ)	$ 3.893	$ (0.368)	$ 3.525
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, Option 4 aligns with principle 2 by bringing the R:C ratios within the range of reasonableness:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules fall within the range of reasonableness. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

However, Option 4 offers no improvement to principle 3, and is not as well aligned with principles 4 and 6 when compared to Options 2a, 2b and 3:

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use</u>**

  Under Option 4, the increase in the Basic Charge for RS 3/23, plus the offset from the reduction in the variable delivery rates, will move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. This is confirmed in Table 5-15 below. Furthermore, as shown in Table 5-16 below, the adjusted rates ensure the economic crossover point between RS 3/23 and RS 5/25 is maintained at a level similar to 2023 Approved rates.

  However, since Option 4 uses RS 2 to absorb all revenue shifts from RS 5/25 and RS 22, there is a resulting increase in the RS 2 variable rates of RS 2. It is therefore not possible to simultaneously decrease the variable rates of RS 2 to address the issue of the economic crossover point between RS 2 and RS 3/23 (i.e., in order to address the economic crossover point between RS 2 and RS 3/23, the Basic Charge of RS 2 will have to be increased which is then offset by reducing the variable charge of RS 2, which is not possible under Option 4 as the variable charge of RS 2 has to be increased to absorb the revenue shift of RS 5/25 and RS 22). As such, to correct the economic crossover between RS 2 and RS 3/23 as well as between RS 3/23 and RS 5/25, the rates of RS 3/23 will have to be changed since RS 3/23 is part of both economic crossover points. The result is that the Basic Charge of RS 3/23 would have to be increased significantly as shown in Table 5-14 above. The increase in the RS 3/23 Basic Charge under Option 4 is even higher than Option 3, i.e., an increase of $1.8639 per day under Option 3 (an approximate increase of $680 per year) versus an increase of $4.0145 per day under Option 4 (an approximate increase of $1,466 per year). This level of increase to the Basic Charge would have a significant impact on the price signal for large commercial customers under RS 3/23 and would discourage any efficient use of energy, contrary to Bonbright's rate design principle 3.

Table 5-15: Economic Crossover Volume between RS 2 and RS 3/23 under Option 4

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		0.9485	8.8040	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	346	3,216	2,869
4					
5	Delivery Charge ($/GJ)		4.708	3.525	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.458	10.024	1.434
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,001	2,001	2,000

Table 5-16: Economic Crossover at Varying Load Factors for Large Commercial (RS 3/23) and General Firm Service (RS 5/25) at Current 2023 Approved Rates and Option 4[87]

		Current 2023 Approved Rates			Option 4	
		RS 3/23	RS 5/25		RS 3/23	RS 5/25
Monthly Charge, Basic + Admin ($/Mth)		185	508		307	508
Demand Charge ($/GJ/Mth)			30.278			28.289
Delivery Charge ($/GJ)		3.893	1.085		3.525	1.014
Load Factor	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume	Economic Cross-over (GJ/Yr)	Daily Demand	Peak Winter Month Volume
50%	4,747	26	709	3,706	20	554
45%	6,509	40	1,081	5,430	33	902
40%	12,144	83	2,268	12,978	89	2,424
39%	15,175	107	2,907	19,106	134	3,661
38%	20,585	148	4,048	37,989	274	7,470
37%	32,976	244	6,659	(911,418)	(6,749)	(184,057)

- **Principle 4 – Customer understanding and acceptance**

  As basic charges usually remain constant during FEI's annal rate changes, significantly increasing the RS 3/23 Basic Charge under Option 4 will likely lead to customer confusion and could impact customer acceptance (especially large commercial customer acceptance) of FEI's rates.

- **Principle 6 – Rate stability (Customer rate impact should be managed)**

  Under Option 4, there will be no bill impact to RS 1 customers, and the bill impacts to the average RS 2 and RS 3/23 customers are relatively small, i.e., 1.1 percent or $44.97 per year for the average RS 2 customer and 0.1 percent or $123.10 per year for the average RS 3/23 customer. However, the large increase in the Basic Charge of RS 3/23 will have a significant impact on large commercial customers that have small or minimal volumes since these customers would have limited to no opportunity to offset the increased Basic Charge through decreased consumption (as shown in Table 5-14 above, the variable charges of RS 3/23 will be reduced under Option 4 to offset some of the increase in the Basic Charge). For example, assuming a particular large commercial customer has no volumes (which could occur over time when the commercial property is under development/renovation, changing ownership/lease, or vacant) and pays the Basic Charge only, they will experience the maximum bill impact of $1,466 per year since this customer would not be able to offset the increase through the reduced variable charges. This level of bill impact is worse than Option 3 and is therefore more misaligned with the rate design principle of rate stability.

[87] Negative economic crossover volume means there is no volume at the specific load factor that RS 3/23 would see a savings for switching to RS 5/25.

5.3.5 Option 5: Revenue Rebalancing Using RS 1 plus Adjustments to RS 2 and RS 3/23 for Maintaining Economic Crossover between RS 2 and RS 3/23

FEI developed Option 5 based on the results of the analysis of Options 1 through 4. Option 5 uses RS 1 to absorb all revenue shifts from RS 5/25 and RS 22 while adjusting the rates of both RS 2 and RS 3/23 to move the economic crossover point between these two rate schedules back to 2,000 GJ per year. This approach is based on the observations from Options 3 and 4 which showed that if RS 2 is used to absorb the revenue shifts (all or partially) from RS 5/25 and RS 22, there will be a significant increase to the Basic Charge of RS 3/23 in order to address the issue of the economic crossover point between RS 2 and RS 3/23. Additionally, Option 5 does not include any further adjustments to the rates of RS 3/23 to account for the reduced economic crossover point between RS 3/23 and RS 5/25 given the potential impact on FEI's revenue is small, as discussed in Options 2a and 2b.

Table 5-17 below provides the initial 2023 COSA results (as presented in Table 4-17) before any rebalancing, the revenue shifts for rebalancing, the approximate bill impacts, and the final 2023 COSA results after the revenue shifts. As with Options 2, 3 and 4, Option 5 includes adjustments to RS 4 and RS 7/27 to maintain their current discount from RS 5/25 (since the RS 5/25 rates are reduced due to rebalancing as explained in Section 5.3.2.1).

Table 5-17: Option 5 – 2023 COSA R:C and M:C Results after Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	4,519	0.4%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	145	0.04%	98.1%	95.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(145)	(0.04%)	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Table 5-18 below summarizes the changes to RS 1, RS 2, RS 3/23, RS 4, RS 5/25, RS 7/27, and RS 22 under Option 5. The impact to RS 1 customers under this option is relatively small at approximately 0.4 percent which, for the average RS 1 customer with 90 GJ of consumption annually, results in an annual bill impact of approximately $4.95. The bill impact for Small Commercial customers under this option is also relatively small at approximately 0.04 percent which, for the average RS 2 customer with 322 GJ of consumption annually, results in an annual bill impact of approximately $1.65. For the Large Commercial customers, their bills will see a relatively small reduction of 0.04 percent which, for the average RS 3/23 customer, results in a reduction of approximately $9.74.

Table 5-18: Summary of Rate Changes under Option 5

Rate Schedule	Current 2023 Approved Rates	Changes	Option 5
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.055	$ 6.065
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.2026	$ 1.1511
Delivery Charge ($/GJ)	$ 4.568	$ (0.225)	$ 4.343
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 0.4730	$ 5.2625
Delivery Charge ($/GJ)	$ 3.893	$ (0.050)	$ 3.843
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, Option 5 aligns with principle 2 by bringing the R:C ratios within the range of reasonableness, and more fully aligns with principles 3, 4 and 6 compared to Options 2a, 2b, 3 and 4:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules fall within the range of reasonableness. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use (Partially)</u>**

Table 5-19 below confirms that, under Option 5, the increase in the Basic Charge for both RS 2 and RS 3/23, plus the offset from the reduction of the variable charges, will move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. Under Option 5, the increase in the Basic Charge for RS 3/23 is much less than under Options 3 and 4, i.e., an increase of $0.4730 per day (or $173 per year) for RS 3/23 under Option 5 versus an increase of $1.8639 per day (or $680 per year) under Option 3 and $4.0145 per day (or $1,466 per year) under Option 4.

Table 5-19: Economic Crossover Volume between RS 2 and RS 3/23 under Option 5

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.1511	5.2625	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	420	1,922	1,502
4					
5	Delivery Charge ($/GJ)		4.343	3.843	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.093	10.342	0.751
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

However, under Option 5, the adjusted rates will not address the reduced economic crossover point between RS 3/23 and RS 5/25 as shown in Table 5-20 below. Since the economic crossover point between RS 3/23 and RS 5/25 is reduced, there would be potentially more RS 3/23 customers that could receive a lower annual bill under RS 5/25. Based on actual 2022 annual consumption, FEI estimates that, under the rates for Option 5, approximately 734 more RS 3/23 customers could receive a lower annual bill with RS 5/25, and the equivalent revenue impact to FEI would be approximately $2.4 million if all customers that could receive a lower bill under RS 5/25 switch from RS 3/23 at the same time. However, as noted in the discussion of Options 2a and 2b, the number of customers that would benefit from switching between the two rate schedules is limited and the overall impact to FEI's revenue requirement is small. For example, 734 customers represent approximately 0.07 percent of FEI's number of customers (2023 Approved) and $2.4 million represents approximately 0.11 percent of FEI's 2023 Approved revenue requirement. FEI considers a small overall impact to its revenue requirement is warranted as a trade-off for the benefits of the much lower increase in the Basic Charge of RS 3/23 when compared to Options 3 and 4, as well as the lower bill impact to both RS 2 and RS 3/23 customers when compared to Options 3 and 4.

Table 5-20: Economic Crossover at Varying Load Factors for Large Commercial (RS 3/23) and General Firm Service (RS 5/25) at Current 2023 Approved Rates and Option 5

	Current 2023 Approved Rates			Option 5		
		RS 3/23	RS 5/25		RS 3/23	RS 5/25
Monthly Charge, Basic + Admin ($/Mth)		185	508		199	508
Demand Charge ($/GJ/Mth)			30.278			28.289
Delivery Charge ($/GJ)		3.893	1.085		3.843	1.014
Load Factor	**Economic Cross-over (GJ/Yr)**	**Daily Demand**	**Peak Winter Month Volume**	**Economic Cross-over (GJ/Yr)**	**Daily Demand**	**Peak Winter Month Volume**
50%	4,747	26	709	3,825	21	572
45%	6,509	40	1,081	4,862	30	807
40%	12,144	83	2,268	7,355	50	1,374
39%	15,175	107	2,907	8,342	59	1,598
38%	20,585	148	4,048	9,714	70	1,910
37%	32,976	244	6,659	11,751	87	2,373

- **<u>Principle 4 – Customer understanding and acceptance (Partially)</u>**

  Although the Basic Charges of RS 2 and RS 3/23 will still be increased under Option 5, the level of the increases is much smaller than under Options 3 and 4. As such, while Option 5 might still lead to customer confusion and could still impact customer acceptance due to the change in the Basic Charges, it is an improvement from Options 3 and 4 given that the impact is much smaller.

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**

  The bill impacts to the average RS 1 and RS 2 customer are relatively small under Option 5, i.e., 0.4 percent or $4.95 per year for the average residential customer and 0.04 percent or $1.65 per year for the average small commercial customer. In fact, the bill impact to RS 2 customers is the smallest out of all the options. And, for the average RS 3 large commercial customer, there will be a relatively small bill reduction of 0.04 percent or $9.74 per year.

  Additionally, the bill impacts due to the increase in the Basic Charges of RS 2 and RS 3/23 are smaller than under Options 3 and 4. For RS 2 customers, the increased Basic Charge is approximately $74 per year under Option 5, which is reduced from $130 per year under Option 3. And for RS 3/23 customers, the increased Basic Charge is approximately $173 per year, which is significantly less than $680 per year under Option 3 and $1,466 per year under Option 4. The reduced bill impact to commercial customers is an improvement from other revenue rebalancing options in terms of the rate design principle of rate stability.

5.3.6 Summary of Revenue Rebalancing Options

Table 5-21 below summarizes the revenue shift and Table 5-22 below summarizes the estimated bill impact in both percentage and in dollars for the average customer by rate schedule for each rebalancing option.

It can be seen from Table 5-21 that the rebalancing required to move both RS 5/25 and RS 22 back within the range of reasonableness is small, i.e., approximately $3.344 million for RS 5/25 and $151 thousand for RS 22, which is approximately 0.15 percent and 0.007 percent of FEI's total revenue at the 2023 approved rates. Furthermore, as Table 5-22 demonstrates, the variations between all rebalancing options is small in terms of bill impact to all customer groups. For example, the annual bill impact to the average residential (RS 1) customer ranges between $0 (or zero percent) and approximately $5 (or 0.4 percent) across all rebalancing options. For the average Small Commercial (RS 2) customer, the bill impact ranges between $0 (zero percent) and approximately $50 (1.2 percent) annually. And for the average Large Commercial (RS 3/23) customer, the annual bill impact ranges between a decrease of approximately $469 (1.2 percent) and an increase of $123 (0.1 percent) across all rebalancing options. The relatively small bill impact to all customer groups and the small difference between all rebalancing options explored demonstrates that the current rates and rate design for FEI's customers are working well and as intended.

Table 5-21: Summary of Revenue Shift between Rate Schedules for all Rebalancing Options ($000s)

	Revenue Shift ($000s)					
	Option 1: Status Quo	Option 2a: Revenue Rebalancing Only Using RS 1	Option 2b: Revenue Rebalancing Only Using RS 2	Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25	Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25	Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only
RS 1	-	4,519	-	4,519	-	4,519
RS 2	-	-	4,519	4,071	4,075	145
RS 3/23	-	-	-	(4,071)	444	(145)
RS 5/25	-	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)
RS 6	-	-	-	-	-	-
RS 22	-	(151)	(151)	(151)	(151)	(151)
RS 22A	-	-	-	-	-	-
RS 22B	-	-	-	-	-	-
RS 4	-	(46)	(46)	(46)	(46)	(46)
RS 7/27	-	(978)	(978)	(978)	(978)	(978)

Table 5-22: Summary of Bill Impact in % and $ for an Average Customer in each Rate Schedule for all Rebalancing Options

	Option 1		Option 2a		Option 2b		Option 3		Option 4		Option 5	
	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)
RS 1	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95
RS 2	-	$ -	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65
RS 3/23	-	$ -	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)
RS 5/25	-	$ -	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)
RS 6	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22	-	$ -	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)
RS 22A	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 4	-	$ -	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)
RS 7/27	-	$ -	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)

When comparing between the different revenue rebalancing options, it can be seen from Table 5-22 above that, except for Option 1 and Option 2a, Option 5 has the least bill impact to the average RS 2 customer at approximately 0.04 percent or $1.65 per year while keeping the bill impact to RS 1 customers relatively small at approximately 0.4 percent or $4.95 per year. Further, Option 5 provides a small reduction to RS 3/23 customer bills at approximately 0.04 percent or $10 per year.

When assessing between the different revenue rebalancing options, Option 5 is able to either fully align with or partially align with the applicable Bonbright rate design principles. Below is a summary of the different revenue rebalancing options in consideration of the applicable rate design principles:

- **<u>Principle 2 – Fair appointment of costs among customers</u>**
  - Option 1 results in the R:C ratios for RS 5/25 and RS 22 continuing to remain above the range of reasonableness of 95 to 105 percent, indicating the cost recovery through existing rates does not reflect a fair appointment of costs from these two customer groups.
  - All other options result in the R:C ratios of all rate schedules falling within the range of reasonableness of 95 percent to 105 percent.
- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use</u>**
  - Options 2a and 2b result in incorrect price signals to some customers under RS 2, RS 3/23, and RS 5/25 due to the unaddressed issue of the economic crossover point between RS 2 and RS 3/23 as well as between RS 3/23 and RS 5/25.
  - Options 3 and 4 address the economic crossover point issue between RS 2 and RS 3/23 as well as between RS 3/23 and RS 5/25; however, this is achieved by substantially increasing the Basic Charges of RS 2 and/or RS 3/23 which will discourage efficient use of energy.
  - Option 5 addresses the economic crossover point issue between RS 2 and RS 3/23 but not between RS 3/23 and 5/25. However, the increase in the Basic Charge under Option 5 for both RS 2 and RS 3/23 is much smaller than Options 3 and 4.
- **<u>Principle 4 – Customer understanding and acceptance</u>**
  - Under Options 3 and 4, the Basic Charges of RS 2 and RS 3/23 increase substantially which likely will lead to customer confusion and could impact customer acceptance (especially small and large commercial customers).
  - Under Option 5, although there is an increase to the Basic Charges of RS 2 and RS 3/23, the level of the increases are much smaller when compared to Options 3 and 4. As such, while Option 5 might still lead to customer confusion and could still impact

customer acceptance, it is an improvement over Options 3 and 4 given the much smaller impact.

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**
  - Except for Option 1 which has no bill impact to any rate schedule, the bill impacts due to all other revenue rebalancing options are relatively small. As shown in Table 5-22 above, the average RS 1 customer bill impact ranges between $0 (or zero percent) and approximately $5 (or 0.4 percent) annually across all rebalancing options. For the average RS 2 customer, the bill impact ranges between $0 (zero percent) and approximately $50 (1.2 percent) annually. And for the average RS 3/23 customer, the bill impact ranges between a decrease of approximately $469 (1.2 percent) and an increase of $123 (0.1 percent) across all rebalancing options.
  - For Options 3 and 4, due to the increase in the Basic Charges to RS 2 and RS 3/23, commercial customers with low annual consumption will experience the largest bill impacts.
  - For Option 5, the bill impacts to commercial customers with low annual consumption will be much smaller when compared to Options 3 and 4 as the increase in the Basic Charges of RS 2 and RS 3/23 is smaller, i.e., an increase of approximately $74 per year for RS 2 customers under Option 5 compared to $130 per year under Option 3; and an increase of approximately $173 per year for RS 3/23 customers under Option 5 compared to $680 per year under Option 3 and $1,466 per year under Option 4.

5.4 *OPTION 5 IS THE PREFERRED REBALANCING OPTION*

Based on the evaluation of the revenue rebalancing options against Bonbright's rate design principles, Option 5 (Revenue Rebalancing using RS 1 plus adjustments to RS 2 and RS 3/23 for maintaining the economic crossover between RS 2 and RS 3/23) is FEI's preferred and proposed option. Option 5 reflects the best balance of the above-discussed rate design principles when compared to the other revenue rebalancing options. Additionally, with the exception of Options 1 and 2a, Option 5 results in the least bill impact to the average RS 2 customer at approximately 0.04 percent or $1.65 per year, while keeping the bill impact to RS 1 customers relatively small at approximately 0.4 percent or $4.95 per year, and also offering a small reduction to RS 3/23 customer bills at approximately 0.04 percent or $10 per year.

5.4.1 Final 2023 COSA Results with Rebalancing

Table 5-23 below presents the final 2023 COSA results after the proposed revenue rebalancing under Option 5. The proposed rebalancing involves:

Residential Service (RS 1):

- Increase the Delivery Charge by $0.055 per GJ as a result of the revenue shifts and rebalancing from RS 22 and RS 5/25;

Small Commercial Service (RS 2):

- Increase the Basic Charge by $0.2026 per Day and decrease the Delivery Charge by $0.225 per GJ in order to align the 2,000 GJ volume threshold with Large Commercial RS 3/23 customers;

Large Commercial Service (RS 3/23):

- Increase the Basic Charge by $0.4730 per Day and decrease the Delivery Charge by $0.050 per GJ in order to align the 2,000 GJ volume threshold with Small Commercial RS 2 customers;

Seasonal Service (RS 4):

- Decrease the Off-Peak Delivery Charge by $0.309 per GJ and the Extension Period Delivery Charge by $0.069 per GJ due to the proposed changes to RS 5/25 such that the current discount from general firm service customers is maintained;

General Firm Service (RS 5/25):

- Decrease the Demand Charge by $1.989 per GJ per Month and the Delivery Charge by $0.071 per GJ as a result of revenue shifts and rebalancing to Residential RS 1;

Natural Gas Vehicle Service (RS 6):

- No change to the current rates to RS 6;

General Interruptible Service (RS 7/27):

- Decrease the Delivery Charge by $0.095 per GJ due to the proposed changes to RS 5/25 such that the current discount from general firm service customers is maintained**;**

Large Volume Transportation Service (RS 22):

- Decrease the Firm Demand Charge by $0.505 per GJ per Month, decrease the Firm MTQ Delivery Charge by $0.009 per GJ, and decrease the Interruptible MTQ Delivery Charge by $0.026 per GJ as a result of revenue shifts and rebalancing to Residential RS 1; and

Transportation (Closed) Service (RS 22A and RS 22B):

- No change to current rates to RS 22A and RS 22B.

Table 5-23: Final 2023 COSA Results with Revenue Rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	4,519	0.4%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	145	0.04%	98.1%	95.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(145)	(0.04%)	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

5.4.2 Comparison of FEI's Current Rates and Proposed Rates

Table 5-24 below summarizes FEI's proposed rate changes and compares them against the current 2023 approved rates. Given that the expected timing of the BCUC's decision on this Application is some time in 2024, FEI requests that the changes resulting from this decision be implemented effective January 1, 2025. As a result, any changes will be implemented as part of FEI's 2025 approved rates.

1 **Table 5-24: FEI Rate Proposal Summary based on 2023 Rates**

Rate Schedule	Current 2023 Approved Rates	Propsoed Rate Changes	Estimated Final Rates After Proposed Changes
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.055	$ 6.065
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.2026	$ 1.1511
Delivery Charge ($/GJ)	$ 4.568	$ (0.225)	$ 4.343
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 0.4730	$ 5.2625
Delivery Charge ($/GJ)	$ 3.893	$ (0.050)	$ 3.843
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 6 - Natural Gas Vehicle			
Basic Charge ($/Day)	$ 2.0041	$ -	$ 2.0041
Delivery Charge ($/GJ)	$ 3.733	$ -	$ 3.733
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

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6. TRANSPORTATION SERVICE MODEL

Since its inception in 1993, the intent of the Transportation Service Model has been to provide an option for the large commercial and industrial customers on FEI's system to source their gas from a shipper agent (marketer) or on their own, and have the gas delivered directly to FEI's system. Transportation Service customers arrange their own commodity and storage and transport (midstream) resources to supply the FEI system with gas at the applicable interconnection points with upstream pipelines. The Transportation Service rate schedules[88] establish the terms and conditions of the transportation service, including operational and system-balancing rules, as well as the charges that customer may incur if balancing provisions are not met.

FEI's storage and transport (midstream) resources are in place to serve FEI's core customers (bundled sales customers)[89] to balance and meet their daily demand needs. FEI must balance its system daily as a whole at the end of each day. FEI does not procure additional midstream resources to meet the daily balancing needs of Transportation Service customers as this is the responsibility of each Transportation Service customer or their shipper agent. The fixed costs of FEI's midstream resources are recovered from FEI's core customers through the applicable Storage and Transport Charge per GJ applicable to FEI's core sales service rate schedules. The Storage and Transport Charge is not applicable to FEI's Transportation Service rate schedules and, as such, Transportation Service customers do not pay for those midstream resources and are not entitled to benefit from them at the expense of core customers.

The 2016 RDA Decision approved, among other things, various changes to the Transportation Service Model, including new and updated customer-balancing tariff terms, conditions and charges (New Rules). The New Rules included the elimination of monthly balancing provisions, the implementation of daily balancing for all transportation service customers, a reduction of the daily balancing tolerance from 20 percent to 10 percent, and a new balancing charge of $0.25 per GJ for balancing within the 10 to 20 percent range. The New Rules were implemented in the Lower Mainland (including Vancouver Island) and Interior regions effective November 1, 2018, and in the Columbia region (including East Kootenay) effective November 1, 2019. The following are all transportation service charges, including the new service charge for balancing threshold between 10 percent and 20 percent implemented under the New Rules, and the description of each:

- **Backstopping**: Gas made available by FEI as an interruptible backup supply if on any day the authorized quantity is less than the requested or nominated quantity. Backstopping is charged at the Sumas Gas Daily Midpoint price.

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[88] Rate schedules 22, 22A, 22B, 23, 25, 26, 27, and 46.

[89] RS 1 to RS 7, and RS 46 (who have elected bundled service) including the applicable rate schedules under the RNG and Customer Choice programs.

- **Monthly Balancing Gas:**[90] Any gas taken at the end of the month which is in excess of the total of the authorized quantity for the month. Monthly Balancing gas is charged at the average of the Sumas Gas Daily Midpoint price throughout the month.
- **Daily Balancing Gas:** Any gas taken during a Day in excess of the authorized quantity. Balancing gas daily is charged at the Sumas Gas Daily Midpoint price.
- **Balancing Service:** A charge per Gigajoule is provided for under-deliveries beyond the 20 percent balancing threshold. Charges are $1.10 per GJ in winter months November to March and $0.30 per GJ for summer months April to October.
- **Balancing Service 10%-20%:** As approved under the New Rules, this is a charge per Gigajoule for under-deliveries within the 10 percent to 20 percent balancing threshold. This is an annual charge at $0.25 per GJ.
- **Replacement Gas:** Gas provided to a Shipper by FEI in the event the Shipper fails to return the Peaking Gas Quantity. Replacement gas is charged at the Sumas Daily Midpoint price plus 20 percent.
- **Unauthorized Overrun – under 5%:** Gas taken on any day in excess of the curtailed amount for under-deliveries between 0 percent and 5 percent. This charge applies during a Hold to Authorized or Supply restriction and is charged at the Sumas Gas Daily Midpoint price.
- **Unauthorized Overrun – over 5%:** Gas taken on any day in excess of the curtailed amount for under-deliveries over 5 percent. This charge applies during a Hold to Authorized or Supply restriction and is charged at the greater of Sumas Gas Daily Midpoint price times 1.5 or $20 CAD.

Additionally, in compliance with the 2016 RDA Decision, on June 15, 2022,[91] FEI filed a written report with the BCUC (Transportation Service Report) for assessing the impact due to the changes to the New Rules. By Order G-372-22 dated December 16, 2022, the BCUC accepted FEI's Transportation Service Report as filed, in which FEI made the following conclusions:

- The New Rules are working as intended;
- The New Rules are providing the appropriate incentive for shipper agents to proactively plan and take necessary actions to better manage the supply and demand balance for their customers;
- Shipper agents have demonstrated they can manage under the New Rules;
- The Transportation Service Model has improved under the New Rules by bringing inventories to more reasonable levels; and

[90] As monthly balancing provisions were eliminated from the RDA Decision, Monthly Balancing gas charges no longer apply.
[91] Originally due to be filed on June 1, 2022, but later extended to June 15, 2022 by BCUC Letter dated May 30, 2022.

- The New Rules bring balancing expectations more in line with industry standards.

As part of the 2022 Transportation Service Report, FEI also committed to two minor modifications to the model: (1) to provide a minimum allocation of imbalance return to groups with smaller demand; and (2) to incorporate a flag to the imbalance return nomination field in WINS when the imbalance return service is restricted.

Order G-372-22 directed FEI to include, as part of its next COSA study filing, an analysis of the costs and revenue associated with its Transportation Service Model.[92] This section addresses this directive from the BCUC and, as discussed below, the costs and revenues associated with the Transportation Service Model have no material impact on FEI's 2023 COSA and do not result in a change to the R:C ratio of any rate schedule.

6.1 *BALANCING COSTS AND REVENUES*

While there are different business models for sales service and Transportation Service, FEI balances the system as a whole on a daily basis on behalf of both sales and transportation customers using midstream resources contracted by FEI, and paid for by FEI's core sales customers, through the Storage and Transportation Charge. The Storage and Transport Charge is not applicable to FEI's transportation rate schedules and, as such, Transportation Service customers do not pay for those midstream resources and are not entitled to benefit from them at the expense of core customers. The New Rules act as an incentive to shipper agents to better match their daily supply with the daily demand requirements from their customers and to nominate and deliver appropriately within the specified ranges. The balancing charges in the tariffs act as a disincentive to shipper agents for failing to balance daily within the applicable tolerance range.

The New Rules and the balancing charges are not designed to be revenue generating or revenue neutral, but rather to act as an incentive for shipper agents to appropriately manage their gas customers' supply requirements. Although the balancing charges are not intended to be revenue generating or revenue neutral, as was presented in the Transportation Service Report (Section 5.5 and Table 5-3), the balancing charge of $0.25 per GJ when balancing in the 10 percent to 20 percent tolerance range is currently at a level that is recovering revenue which is reasonably close to the incremental variable costs required to balance the system as a whole. Thus, in most cases, the costs of the incremental midstream resources needed to balance the system as a whole will be offset by the recoveries from the balancing charge. This means that the impact to FEI's midstream costs is typically minimal and, as noted in the Transportation Service Report, FEI will monitor the midstream costs and periodically perform the cost-based calculation and will bring forward an application for revised balancing charges in the future, if necessary, to ensure impacts, if any, to FEI's midstream costs remain relatively low.

In order to assess the total actual revenue from balancing charges recovered between 2018 and 2022, FEI presents Table 6-1 below, which is expanded from the Transportation Service Report

[92] Directive 2.

(Table 5-5[93]), and includes the addition of the actual full year of balancing charges for 2022. As the table below shows, the five-year average of total balancing charges recovered from 2018 to 2022 was approximately $1.754 million, which is approximately 1.1 percent of FEI's average total midstream costs per year over the same period, or approximately 0.08 percent of FEI's total allocated cost of service included in the 2023 COSA.[94]

FEI notes the actual 2022 total balancing charges are higher than other years, however, out of the total charges of $4.827 million, approximately $3.981 million was due to Unauthorized Over-Run charges during the month of December. In response to cold weather, FEI issued a Province-wide Hold to Authorized restriction for 8 days and a Curtailment restriction for 3 days for customers in the Lower Mainland exclusively due to design day temperatures. Due to higher volumes of under-deliveries resulting in charges combined with the volatility of the Sumas price during the month of December, the elevated prices during these restriction periods resulted in higher Unauthorized Over-Run charges. Excluding the balancing charges from December 2022, the five-year average of total balancing charges would reduce from $1.754 million to approximately $0.957 million, which is equivalent to approximately 0.6 percent of FEI's average total midstream costs, or 0.04 percent when compared to FEI's total allocated cost of service.

Table 6-1: Total Transportation Service Balancing Charges vs. FEI's Total Midstream Costs (2018 to 2022 Actual)

	2018	2019	2020	2021	2022	Average
Total Balancing Charge ($000s)	696	2,385	433	428	4,827	1,754
Total FEI Midstream Costs ($000s)	177,977	188,029	186,092	178,533	91,350	164,396
% of Balance Charge to Total Midstream	0.4%	1.3%	0.2%	0.2%	5.3%	1.1%

Given the relatively small amount of revenue related to the balancing of FEI's Transportation Service Model when compared to FEI's total allocated cost of service, Table 6-2 below confirms that there is no material change to the R:C or M:C ratios even if FEI were to include the balancing revenues in the 2023 COSA model. As such, the balancing revenues will have no material impact to the allocation of costs between each rate schedule or change the results of the 2023 COSA.

93 Table 5-5, page 36.

94 FEI's total allocated cost of service in the 2023 COSA = $1.054 billion for delivery costs + $1.134 billion for gas costs (see Table 4-6).

Table 6-2: Impact to R:C and M:C ratios in 2023 COSA due to Balancing Charges in Transportation Service Model

Rate Schedule	COSA (Before Rebalancing)		Change		COSA (Incl. 5-yr Avg. Balancing Charge)	
	R:C	M:C	R:C	M:C	R:C	M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	0.0%	0.0%	97.4%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	0.0%	0.0%	98.0%	95.5%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	0.0%	-0.1%	104.0%	111.1%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	0.0%	0.0%	106.9%	126.9%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	0.0%	-0.1%	96.2%	90.9%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	0.2%	0.2%	110.2%	110.4%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	0.2%	0.2%	102.0%	102.0%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	0.2%	0.2%	100.3%	100.3%

Rate Schedule (Rates Not Set Using Allocated Costs)	COSA (Before Rebalancing)		Change		COSA (Incl. 5-yr Avg. Balancing Charge)	
	R:C	M:C	R:C	M:C	R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	338.9%	-0.1%	-0.8%	124.0%	338.1%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	-0.1%	0.0%	122.3%	627.9%

6.2 SUMMARY

As described in the Transportation Service Report accepted by the BCUC in Order G-372-22, the New Rules approved and implemented in accordance with the 2016 RDA Decision are working as intended, system inventories are reasonable, and shipper agents are generally able to maintain a daily balance within the 10 percent tolerance with a minimal amount of balancing charges incurred. As directed by Order G-372-22, FEI has analysed the costs and revenues associated with the Transportation Service model and concluded that, given that the amount of balancing charges under the Transportation Service Model are minimal and are mostly offset by the incremental variable costs to balance the system, there is no material impact to FEI's midstream costs and also no material impact to FEI's 2023 COSA. Therefore, FEI concludes that the Transportation Service Model and its related charges continue to be reasonable and appropriate, and no changes to the Transportation Service Model are being proposed as part of this Application.

7. CONCLUSION

As presented in Section 4.6 of this Application, the 2023 COSA shows that, except for RS 5/25 and RS 22, the R:C ratios for all applicable rate schedules are within the range of reasonableness of 95 percent and 105 percent, which is the accepted range for R:C ratios for evaluating the adequacy of each rate schedule to recover its allocated cost of service. Further, the RS 5/25 and RS 22 R:C ratios are only slightly above the upper bound range of reasonableness of 105 percent. Therefore, the 2023 COSA results demonstrate that FEI's existing rates and rate designs are largely working as intended. Given only minor revenue rebalancing is needed for RS 5/25 and RS 22 with minimal impact to all other customers, a comprehensive redesign of FEI's existing rates is not warranted at this time.

As such, based on the results of the 2023 COSA and the considerations set out in Sections 5.1 and 5.2 of this Application, FEI seeks approval of its preferred revenue rebalancing proposal (Option 5), as described in Section 5.4. The proposed revenue rebalancing option results in a reasonable balance of rate design principles, and just and reasonable rates for customers. A Draft Order setting out the approvals sought is provided in Appendix A of the Application.

Appendix A
DRAFT ORDERS

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.
2023 Cost of Service Allocation Study and Application for Approval of Revenue Rebalancing

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On July 20, 2023, FortisBC Energy Inc. (FEI) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), its 2023 Cost of Service Allocation (COSA) Study and application for approval of revenue rebalancing, effective January 1, 2025 (Application);

B. On January 9, 2018, the BCUC issued its Decision and Order G-4-18 on FEI's 2016 COSA (2016 COSA Decision) and on July 20, 2018, the BCUC issued its final Decision and Order G-135-18 on FEI's 2016 Rate Design Application (2016 RDA Decision) directing, among other things, for FEI to file a comprehensive and updated COSA study for each of FEI and FEI – Fort Nelson Service Area five years after the release of the 2016 RDA Decision;

C. In the Application, FEI requests approval of revenue and rate rebalancing proposals, including the following changes to rate schedules:

    1. For Rate Schedule (RS) 1, RS 1U, and RS 1B, increase the Delivery Charge by $0.055 per GJ;

    2. For RS 2, RS 2U, RS 2B, RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.2026 per Day from $0.9485 to $1.511 per Day, and decrease the Delivery Charge by $0.225 per GJ;

    3. For RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.4730 per Day from $4.7895 to $5.2625 per Day, and decrease the Delivery Charge by $0.050 per GJ;

    4. For RS 4, decrease the Off-Peak Delivery Charge by $0.309 per GJ and the Extension Period Delivery Charge by $0.069 per GJ;

5. For RS 5, RS 5B, and RS 25, decrease the Demand Charge by $1.989 per GJ per month, and decrease the Delivery Charge by $0.071 per GJ;

6. For RS 7 and RS 27, decrease the Delivery Charge by $0.095 per GJ; and

7. For RS 22, decrease the Firm Demand Charge by $0.505 per GJ per month, decrease the Firm MTQ Delivery Charge by $0.009 per GJ, and decrease the Interruptible MTQ Delivery Charge by $0.026 per GJ; and

D. The BCUC has commenced review of the Application and considers that the establishment of a public hearing is warranted.

NOW THEREFORE the BCUC orders as follows:

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

2. FEI is directed to publish this order and the regulatory timetable on its website and provide a copy of this order by Friday, August 25, 2023, electronically where possible, to the registered interveners in the following proceedings:

    a. FEI's 2016 Rate Design Application;

    b. FEI's 2022 Transportation Service Report; and

    c. FEI's Annual Review for 2023 Delivery Rates.

3. In accordance with the BCUC's Rules of Practice and Procedure, parties who wish to actively participate in this proceeding must submit the Request to Intervener Form, available on the BCUC's website at https://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the regulatory timetable.

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

Attachment

FortisBC Energy Inc.
2023 Cost of Service Allocation Study and Application for Approval of Revenue Rebalancing

REGULATORY TIMETABLE

Action	Date (2023)
FEI provides Notice of Application	Friday, August 25
Registration of Interveners	Thursday, September 14
BCUC & Intervener Information Request (IR) No. 1	Thursday, October 5
FEI Responses to BCUC and Intervener IR No. 1	Thursday, November 23
FEI Written Final Argument	Thursday, December 14
Action	**Date (2024)**
Intervener Written Final Arguments	Thursday, January 18
FEI Written Reply Argument	Thursday, February 8

British Columbia Utilities Commission
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ORDER NUMBER
G-xx-xx

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

and

FortisBC Energy Inc.
2023 Cost of Service Allocation Study and Application for Approval of Revenue Rebalancing

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On July 20, 2023, FortisBC Energy Inc. (FEI) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), the 2023 Cost of Service Allocation (COSA) Study and application for approval of revenue rebalancing, effective January 1, 2025 (Application);

B. On January 9, 2018, the BCUC issued its Decision and Order G-4-18 on FEI's 2016 COSA (2016 COSA Decision) and on July 20, 2018, the BCUC issued its final Decision and Order G-135-18 on FEI's 2016 Rate Design Application (2016 RDA Decision) directing, among other things, for FEI to file a comprehensive and updated COSA study for each of FEI and FEI – Fort Nelson Service Area five years after the release of the 2016 RDA Decision;

C. In the Application, FEI requests approval of revenue and rate rebalancing proposals, including the following changes to rate schedules:

    1. For Rate Schedule (RS) 1, RS 1U, and RS 1B, increase the Delivery Charge by $0.055 per GJ;

    2. For RS 2, RS 2U, RS 2B, RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.2026 per Day from $0.9485 to $1.511 per Day, and decrease the Delivery Charge by $0.225 per GJ;

    3. For RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.4730 per Day from $4.7895 to $5.2625 per Day, and decrease the Delivery Charge by $0.050 per GJ;

    4. For RS 4, decrease the Off-Peak Delivery Charge by $0.309 per GJ and the Extension Period Delivery Charge by $0.069 per GJ;

5. For RS 5, RS 5B, and RS 25, decrease the Demand Charge by $1.989 per GJ per month, and decrease the Delivery Charge by $0.071 per GJ;

6. For RS 7 and RS 27, decrease the Delivery Charge by $0.095 per GJ; and

7. For RS 22, decrease the Firm Demand Charge by $0.505 per GJ per month, decrease the Firm MTQ Delivery Charge by $0.009 per GJ, and decrease the Interruptible MTQ Delivery Charge by $0.026 per GJ; and

D. The BCUC has reviewed the Application and considers that approval is warranted.

NOW THEREFORE pursuant to sections 58 to 61 of the UCA, the BCUC orders as follows:

1. FEI's revenue rebalancing proposals are approved, effective January 1, 2025, along with implementation of the requested rate changes to its rate schedules described in the Application, as outlined below.

   a. For Rate Schedule (RS) 1, RS 1U, and RS 1B, increase the Delivery Charge by $0.055 per GJ.

   b. For RS 2, RS 2U, RS 2B, RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.2026 per Day from $0.9485 to $1.511 per Day, and decrease the Delivery Charge by $0.225 per GJ.

   c. For RS 3, RS 3U, RS 3B, and RS 23, increase the Basic Charge by $0.4730 per Day from $4.7895 to $5.2625 per Day, and decrease the Delivery Charge by $0.050 per GJ.

   d. For RS 4, decrease the Off-Peak Delivery Charge by $0.309 per GJ and the Extension Period Delivery Charge by $0.069 per GJ.

   e. For RS 5, RS 5B, and RS 25, decrease the Demand Charge by $1.989 per GJ per month, and decrease the Delivery Charge by $0.071 per GJ.

   f. For RS 7 and RS 27, decrease the Delivery Charge by $0.095 per GJ.

   g. For RS 22, decrease the Firm Demand Charge by $0.505 per GJ per month, decrease the Firm MTQ Delivery Charge by $0.009 per GJ, and decrease the Interruptible MTQ Delivery Charge by $0.026 per GJ.

2. FEI is directed to file revised tariff pages with the BCUC for endorsement within 15 days prior to the effective date the effective date of these changes.

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

Appendix B

FEI ANNUAL REVIEW FOR 2023 RATES
APPROVED FINANCIAL SCHEDULES (G-352-22)

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Schedule 1

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (0.491)		
3	Change in Other Revenue	(0.382)	(0.873)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	19.462		
7	Capitalized Overhead Change	(3.416)	16.046	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		12.583	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.125)		
14	Deferrals	6.217	6.092	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	5.844		
18	Financing Ratio Changes	(3.126)		
19	Rate Base Growth	32.743	35.461	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	5.747		
23	Other Income Taxes Changes	(0.464)	5.283	
24				
25				
26	**REVENUE DEFICIENCY (SURPLUS)**		**$ 74.592**	Schedule 16, Line 11, Column 4
27				
28	Non-Bypass Margin at 2022 Approved Rates		969.511	Schedule 19, Line 17, Column 3
29	Rate Change		7.69%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 2

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 7,867,224	$ 8,229,457	$ 362,233	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 35, Column 4
3	Net Additions	355,808	597,313	241,505	Schedule 6.2, Line 35, Columns 5+6+7
4	Plant in Service, Ending	8,223,032	8,826,770	603,738	
5					
6	Accumulated Depreciation Beginning	$ (2,423,184)	$ (2,576,982)	$ (153,798)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(152,345)	(156,392)	(4,047)	Schedule 7.2, Line 35, Columns 7+8
9	Accumulated Depreciation Ending	(2,575,529)	(2,733,374)	(157,845)	
10					
11	CIAC, Beginning	$ (451,881)	$ (459,077)	$ (7,196)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(5,852)	(6,795)	(943)	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(457,733)	(465,872)	(8,139)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 187,384	$ 196,884	$ 9,500	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,628	8,753	125	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	196,012	205,637	9,625	
20					
21	Net Plant in Service, Mid-Year	$ 5,282,663	$ 5,611,722	$ 329,059	
22					
23	Adjustment for timing of Capital additions	$ 49,088	$ 122,435	$ 73,347	
24	Capital Work in Progress, No AFUDC	42,035	42,846	811	
25	Unamortized Deferred Charges	(32,829)	52,970	85,799	Schedule 11.1, Line 29, Column 10
26	Working Capital	68,253	113,461	45,208	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	689,807	747,445	57,638	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(689,807)	(747,445)	(57,638)	Schedule 15, Line 6, Column 3
29	LILO Benefit	(3)	-	3	
30					
31	Mid-Year Utility Rate Base	$ 5,409,207	$ 5,943,434	$ 534,227	

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	3.944%		
4	Labour Split							
5	Non Labour		48.000%	48.000%	49.000%	49.000%		
6	Labour		52.000%	52.000%	51.000%	51.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	3.753%	3.920%	4.432%		
8	Productivity Factor	G-165-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.290%	3.253%	3.420%	3.932%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		1,031,862	1,044,622	1,057,086	1,066,393		
14	Average Customers for the Year	Schedule 19, Line 30, Column 9	1,044,622	1,057,086	1,066,393	1,074,714		
15	Change in Average Customers	Line 14 - Line 13	12,760	12,464	9,307	8,320	42,851	
16	Customer Growth Factor Multiplier	G-165-20					75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16					32,138	
18								
19	**Average Customer Continuity for Rate Setting Purposes**							
20	Average Customers Used to Determine Starting UCOM	Line 13, Column 3					1,031,862	
21								
22	Average Customer Forecast - Rate Setting Purposes	Line 17 + Line 20					1,064,000	
23	FEFN Common Rates Customer True-Up						2,294	
24	Average Customer Forecast - Rate Setting Purposes						1,066,294	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 4

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2022 Unit Cost Growth Capital	$ 4,046				
3	2023 Net Inflation Factor	3.932%				Schedule 3, Line 9, Column 6
4	2023 Unit Cost Growth Capital	$ 4,205				
5	2023 Gross Customer Additions	16,000				
6	2023 Inflation Indexed Growth Capital	$ 67,280			$ 67,280	
7	2021 Growth Capital Customer True-Up				16,798	
8	2023 System Extension Fund				1,000	
9	2023 Growth CIAC				2,453	
10	2023 Inflation Indexed Gross Growth Capital				$ 87,531	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,034		
14	Biomethane Assets			58,571		
15	NGT Assets			5,387		
16	Sustainment Capital			129,336		
17	Other Capital			54,514		
18	Sub-total			$ 248,842	248,842	
19						
20	**Total Capital Expenditures Before CIAC**				$ 336,373	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars		2023 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	87,531	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures		248,842	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$	336,373	
5				
6	**Special Projects and CPCN's**			
7	Tilbury 1A Expansion	$	2,177	
8	LMIPSU CPCN		6	
9	Inland Gas Upgrade		56,518	
10	Transmission Integrity Program (CTS TIMC)		29,551	
11	Pattullo Gasline Replacement		3,481	
12	Gibsons Capacity Upgrade		6,950	
13	Total Capital Expenditures	$	98,683	
14				
15	**Total Capital Expenditures**	$	435,056	
16				
17				
18	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
19				
20	Regular Capital Expenditures	$	336,373	Line 4
21	Add - Capitalized Overheads		56,740	Schedule 20, Line 27, Column 4
22	Add - AFUDC		5,226	
23	Gross Capital Expenditures		398,339	
24	Change in Work in Progress		19,669	
25	**Total Regular Additions to Plant**	$	418,008	
26				
27	Special Projects and CPCN's Capital Expenditures	$	98,683	Line 13
28	Add - AFUDC		4,899	
29	Gross Capital Expenditures		103,582	
30	Change in Work in Progress		143,306	
31	**Total Special Projects and CPCN Additions to Plant**	$	246,888	
32				
33	**Grand Total Additions to Plant**	$	664,896	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	-	-	-	-	-	-	
4	178-00	Organization Expense	728	-	-	-	-	728	
5	401-01	Franchise and Consents	197	-	-	-	-	197	
6	402-11	Utility Plant Acquisition Adjustment	-	-	-	-	-	-	
7	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
9	461-01	Transmission Land Rights	53,064	-	-	-	-	53,064	
10	461-02	Transmission Land Rights - Mt. Hayes	609	-	-	-	-	609	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
13	471-01	Distribution Land Rights	3,502	-	-	-	-	3,502	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	66,775	-	-	11,870	(5,984)	72,661	
16	402-02	Application Software - 20%	37,446	-	-	11,589	(3,956)	45,079	
17			$ 168,677	$ -	$ -	$ 23,459	$ (9,940)	$ 182,196	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	-	-	-	-	1,199	
22	433-00	Manufact'd Gas - Equipment	610	-	-	-	-	610	
23	434-00	Manufact'd Gas - Gas Holders	2,955	-	-	-	-	2,955	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	-	-	-	-	1,714	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	100,809	-	-	-	-	100,809	
28	443-00	Gas Holders - Storage (Tilbury)	180,974	-	-	-	-	180,974	
29	448-11	Piping (Tilbury)	48,635	-	-	-	-	48,635	
30	448-21	Pre-treatment (Tilbury)	38,682	-	70	-	-	38,752	
31	448-31	Liquefaction Equipment (Tilbury)	92,672	-	2,107	-	-	94,779	
32	449-00	Local Storage Equipment (Tilbury)	27,862	-	-	-	-	27,862	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	-	-	-	-	19,045	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	-	-	-	-	61,774	
36	448-41	Send out Equipment(Tilbury)	7,746	-	-	20,426	-	28,172	
37	448-51	Sub-station and Electric (Tilbury)	36,846	-	-	-	-	36,846	
38	448-61	Control Room (Tilbury)	3,805	-	-	-	-	3,805	
39	448-10	Piping (Mount Hayes)	12,455	-	-	-	-	12,455	
40	448-20	Pre-treatment (Mount Hayes)	29,238	-	-	-	-	29,238	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	-	-	-	-	28,880	
42	448-40	Send out Equipment (Mount Hayes)	23,552	-	-	-	-	23,552	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
44	448-60	Control Room (Mount Hayes)	6,425	-	-	-	-	6,425	
45	448-65	MH Inspection (Mount Hayes)	-	-	-	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	-	-	-	-	5,727	
47			$ 770,038	$ -	$ 2,177	$ 20,426	$ -	$ 792,641	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,805	$ -	$ -	$ 349	$ -	$ 11,154	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	38,679	-	-	1,622	(254)	40,047	
5	463-00	Measuring Structures	20,274	-	-	4,241	(143)	24,372	
6	464-00	Other Structures & Improvements	12,622	-	-	-	-	12,622	
7	465-00	Mains	1,612,547	-	84,096	12,938	(1,120)	1,708,461	
8	465-20	Mains - INSPECTION	52,083	-	1,817	13,517	(5,759)	61,658	
9	465-11	IP Transmission Pipeline - Whistler	58,689	-	-	207	-	58,896	
10	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
11	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
12	466-00	Compressor Equipment	203,229	-	-	1,914	(478)	204,665	
13	466-10	Compressor Equipment - OVERHAUL	8,199	-	-	633	(2,323)	6,509	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	-	-	-	-	8,276	
15	467-10	Measuring & Regulating Equipment	103,999	-	1,247	3,160	(120)	108,286	
16	467-20	Telemetering	18,305	-	-	501	(11)	18,795	
17	467-31	IP Intermediate Pressure Whistler	404	-	-	-	-	404	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
19	468-00	Communication Structures & Equipment	13,428	-	-	-	-	13,428	
20			$ 2,169,508	$ -	$ 87,160	$ 39,082	$ (10,208)	$ 2,285,542	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,457	$ -	$ -	$ 90	$ -	$ 5,547	
24	472-00	Structures & Improvements	63,261	-	-	505	(17)	63,749	
25	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
26	473-00	Services	1,504,344	-	-	88,644	(3,680)	1,589,308	
27	474-00	House Regulators & Meter Installations	158,627	-	-	24,921	(6,183)	177,365	
28	474-02	Meters/Regulators Installations	237,903	-	-	-	-	237,903	
29	475-00	Mains	2,071,208	-	157,551	81,196	(4,872)	2,305,083	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	231,440	-	-	12,315	(706)	243,049	
32	477-20	Telemetering	23,957	-	-	1,429	(83)	25,303	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	317,102	-	-	21,568	(5,873)	332,797	
35	478-20	Instruments	16,172	-	-	525	-	16,697	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 4,630,362	$ -	$ 157,551	$ 231,193	$ (21,414)	$ 4,997,692	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 777	$ -	$ -	$ 6,021	$ -	$ 6,798	
41	475-10	Bio Gas Mains – Municipal Land	3,098	-	-	23,748	-	26,846	
42	475-20	Bio Gas Mains – Private Land	398	-	-	-	-	398	
43	418-10	Bio Gas Purification Overhaul	24	-	-	-	-	24	
44	418-20	Bio Gas Purification Upgrader	11,563	-	-	28,334	-	39,897	
45	477-40	Bio Gas Reg & Meter Equipment	3,819	-	-	4,666	-	8,485	
46	478-30	Bio Gas Meters	41	-	-	248	-	289	
47	474-10	Bio Gas Reg & Meter Installations	770	-	-	1,680	-	2,450	
48	483-25	RNG Comp S/W	-	-	-	-	-	-	
49			$ 20,490	$ -	$ -	$ 64,697	$ -	$ 85,187	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,373	$ -	$ -	$ -	$ -	$ 18,373	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	-	-	-	-	13,714	
4	476-30	NG Transportation CNG Foundations	3,141	-	-	-	-	3,141	
5	476-40	NG Transportation LNG Foundations	1,049	-	-	-	-	1,049	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	-	-	-	-	77	
7	476-60	NG Transportation CNG Dehydrator	809	-	-	-	-	809	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 37,163	$ -	$ -	$ -	$ -	$ 37,163	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 31,307	$ -	$ -	$ -	$ -	$ 31,307	
13	482-10	Frame Buildings	25,365	-	-	706	-	26,071	
14	482-20	Masonry Buildings	128,253	-	-	1,974	(50)	130,177	
15	482-30	Leasehold Improvement	3,224	-	-	2,981	(54)	6,151	
16	483-30	GP Office Equipment	3,408	-	-	133	(42)	3,499	
17	483-40	GP Furniture	22,239	-	-	2,292	(412)	24,119	
18	483-10	GP Computer Hardware	48,639	-	-	11,624	(19,674)	40,589	
19	483-20	GP Computer Software	4,143	-	-	-	(635)	3,508	
20	484-00	Vehicles	61,411	-	-	9,146	-	70,557	
21	484-10	Vehicles - Leased	13,963	-	-	-	(1,458)	12,505	
22	485-10	Heavy Work Equipment	750	-	-	4	-	754	
23	485-20	Heavy Mobile Equipment	9,277	-	-	1,720	-	10,997	
24	486-00	Small Tools & Equipment	60,652	-	-	7,124	(3,556)	64,220	
25	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
26	488-10	Telephone	1,223	-	-	-	(139)	1,084	
27	488-20	Radio	19,365	-	-	1,446	-	20,811	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 433,219	$ -	$ -	$ 39,150	$ (26,020)	$ 446,349	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 8,229,457	$ -	$ 246,888	$ 418,007	$ (67,582)	$ 8,826,770	
36									
37		Cross Reference			Schedule 5, Line 31, Column 2	Schedule 5, Line 25, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 66	$ -	$ 1	$ -	$ -	$ -	$ 67	
3	175-00	Unamortized Conversion Expense - Squamish	-	10.00%	-	-	-	-	-	-	-	
4	178-00	Organization Expense	728	1.00%	464	-	7	-	-	-	471	
5	401-01	Franchise and Consents	197	1.08%	149	-	2	-	-	-	151	
6	402-11	Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	
7	402-03	Other Intangible Plant	1,907	2.50%	1,294	-	48	-	-	-	1,342	
8	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	53,064	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
13	471-01	Distribution Land Rights	3,502	0.00%	248	-	-	-	-	-	248	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	66,775	12.50%	27,775	-	8,347	(5,984)	-	-	30,138	
16	402-02	Application Software - 20%	37,446	20.00%	8,732	-	7,488	(3,956)	-	-	12,264	
17			$ 168,677		$ 40,514	$ -	$ 15,893	$ (9,940)	$ -	$ -	$ 46,467	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	455	-	30	-	-	-	485	
22	433-00	Manufact'd Gas - Equipment	610	5.00%	375	-	30	-	-	-	405	
23	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	951	-	74	-	-	-	1,025	
24	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	198	-	15	-	-	-	213	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,330	-	86	-	-	-	1,416	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	100,809	2.20%	13,301	-	2,218	-	-	-	15,519	
28	443-00	Gas Holders - Storage (Tilbury)	180,974	1.23%	22,823	-	2,225	-	-	-	25,048	
29	448-11	Piping (Tilbury)	48,635	2.45%	4,283	-	1,192	-	-	-	5,475	
30	448-21	Pre-treatment (Tilbury)	38,752	3.84%	5,217	-	1,488	-	-	-	6,705	
31	448-31	Liquefaction Equipment (Tilbury)	94,779	2.45%	8,555	-	2,322	-	-	-	10,877	
32	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	20,494	-	772	-	-	-	21,266	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	8,295	-	733	-	-	-	9,028	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	11,656	-	1,019	-	-	-	12,675	
36	448-41	Send out Equipment(Tilbury)	7,746	2.41%	695	-	187	-	-	-	882	
37	448-51	Sub-station and Electric (Tilbury)	36,846	2.41%	3,530	-	888	-	-	-	4,418	
38	448-61	Control Room (Tilbury)	3,805	6.09%	910	-	232	-	-	-	1,142	
39	448-10	Piping (Mount Hayes)	12,455	2.45%	3,415	-	305	-	-	-	3,720	
40	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	13,192	-	1,123	-	-	-	14,315	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	8,262	-	708	-	-	-	8,970	
42	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	6,634	-	568	-	-	-	7,202	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	6,191	-	525	-	-	-	6,716	
44	448-60	Control Room (Mount Hayes)	6,425	6.09%	4,587	-	391	-	-	-	4,978	
45	448-65	MH Inspection (Mount Hayes)	-	20.00%	-	-	-	-	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	1,172	-	176	-	-	-	1,348	
47			$ 772,215		$ 146,522	$ -	$ 17,307	$ -	$ -	$ -	$ 163,829	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,805	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	-	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	38,679	3.32%	21,341	-	1,284	(254)	-	-	22,371	
5	463-00	Measuring Structures	20,274	2.13%	9,099	-	432	(143)	-	-	9,388	
6	464-00	Other Structures & Improvements	12,622	3.62%	4,335	-	457	-	-	-	4,792	
7	465-00	Mains	1,696,643	1.46%	494,710	-	24,771	(1,120)	-	-	518,361	
8	465-20	Mains - INSPECTION	53,900	15.20%	17,732	-	8,194	(5,759)	-	-	20,167	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	9,142	-	904	-	-	-	10,046	
10	465-30	Mt Hayes - Mains	6,307	1.54%	1,175	-	97	-	-	-	1,272	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,635	-	69	-	-	-	1,704	
12	466-00	Compressor Equipment	203,229	2.42%	110,291	-	4,918	(478)	-	-	114,731	
13	466-10	Compressor Equipment - OVERHAUL	8,199	10.19%	5,881	-	836	(2,323)	-	-	4,394	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	2.34%	2,031	-	194	-	-	-	2,225	
15	467-10	Measuring & Regulating Equipment	105,246	2.12%	32,817	-	2,231	(120)	-	-	34,928	
16	467-20	Telemetering	18,305	8.97%	16,520	-	1,642	(11)	-	-	18,151	
17	467-31	IP Intermediate Pressure Whistler	404	2.26%	135	-	9	-	-	-	144	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	52	-	7	-	-	-	59	
19	468-00	Communication Structures & Equipment	13,428	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 2,256,668		$ 731,792	$ -	$ 46,045	$ (10,208)	$ -	$ -	$ 767,629	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	63,261	2.15%	13,681	-	1,360	(17)	-	-	15,024	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	89	-	6	-	-	-	95	
26	473-00	Services	1,504,344	2.18%	419,422	-	32,795	(3,680)	-	-	448,537	
27	474-00	House Regulators & Meter Installations	158,627	7.45%	113,086	-	11,818	(6,183)	-	-	118,721	
28	474-02	Meters/Regulators Installations	237,903	4.55%	55,262	-	10,825	-	-	-	66,087	
29	475-00	Mains	2,228,759	1.35%	587,402	-	30,088	(4,872)	-	-	612,618	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	231,440	2.51%	71,475	-	5,809	(706)	-	-	76,578	
32	477-20	Telemetering	23,957	3.59%	8,496	-	860	(83)	-	-	9,273	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	317,102	6.06%	195,722	-	19,215	(5,873)	-	-	209,064	
35	478-20	Instruments	16,172	2.92%	8,122	-	472	-	-	-	8,594	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,787,913		$ 1,474,398	$ -	$ 113,248	$ (21,414)	$ -	$ -	$ 1,566,232	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 777	2.69%	$ 166	$ -	$ 21	$ -	$ -	$ -	$ 187	
41	475-10	Bio Gas Mains – Municipal Land	3,098	1.56%	193	-	49	-	-	-	242	
42	475-20	Bio Gas Mains – Private Land	398	1.56%	19	-	6	-	-	-	25	
43	418-10	Bio Gas Purification Overhaul	24	5.00%	9	-	1	-	-	-	10	
44	418-20	Bio Gas Purification Upgrader	11,563	5.00%	3,847	-	578	-	-	-	4,425	
45	477-40	Bio Gas Reg & Meter Equipment	3,819	3.22%	714	-	123	-	-	-	837	
46	478-30	Bio Gas Meters	41	4.89%	18	-	2	-	-	-	20	
47	474-10	Bio Gas Reg & Meter Installations	770	5.32%	116	-	41	-	-	-	157	
48	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
49			$ 20,490		$ 5,082	$ -	$ 821	$ -	$ -	$ -	$ 5,903	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.2
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Natural Gas for Transportation**										
2	476-10	NG Transportation CNG Dispensing Equipment	18,373	5.00%	$ 5,225	-	919	-	-	-	$ 6,144	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	5.00%	4,905	-	686	-	-	-	5,591	
4	476-30	NG Transportation CNG Foundations	3,141	5.00%	943	-	157	-	-	-	1,100	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	446	-	52	-	-	-	498	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	50	-	1	-	-	-	51	
7	476-60	NG Transportation CNG Dehydrator	809	5.00%	229	-	40	-	-	-	269	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 37,163		$ 11,798	$ -	$ 1,855	$ -	$ -	$ -	$ 13,653	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,307	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	25,365	3.17%	14,427	-	804	-	-	-	15,231	
14	482-20	Masonry Buildings	128,253	1.52%	36,789	-	1,949	(50)	-	-	38,688	
15	482-30	Leasehold Improvement	3,224	9.49%	1,602	-	198	(54)	-	-	1,746	
16	483-30	GP Office Equipment	3,408	6.67%	1,389	-	227	(42)	-	-	1,574	
17	483-40	GP Furniture	22,239	5.00%	6,159	-	1,112	(412)	-	-	6,859	
18	483-10	GP Computer Hardware	48,639	25.00%	24,620	-	12,122	(19,674)	-	-	17,068	
19	483-20	GP Computer Software	4,143	12.50%	2,902	-	518	(635)	-	-	2,785	
20	484-00	Vehicles	61,411	11.07%	26,118	-	6,796	-	-	-	32,914	
21	484-10	Vehicles - Leased	13,963	9.44%	13,785	-	68	(1,458)	-	-	12,395	
22	485-10	Heavy Work Equipment	750	5.14%	526	-	39	-	-	-	565	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	5,283	-	565	-	-	-	5,848	
24	486-00	Small Tools & Equipment	60,652	5.00%	25,493	-	3,033	(3,556)	-	-	24,970	
25	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
26	488-10	Telephone	1,223	6.67%	1,081	-	82	(139)	-	-	1,024	
27	488-20	Radio	19,365	6.67%	6,685	-	1,292	-	-	-	7,977	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 433,219		$ 166,876	$ -	$ 28,805	$ (26,020)	$ -	$ -	$ 169,661	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 8,476,345		$ 2,576,982	$ -	$ 223,974	$ (67,582)	$ -	$ -	$ 2,733,374	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(821)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(2,540)					
38		**Net Depreciation Expense**					$ 220,613					
39												
40		Cross Reference	Schedule 6.2, Line 35, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars			12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Non-Regulated Plant**									
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	-	176,594	
4									-	
5	**Total**			$ 177,648	$ -	$ -	$ -	$ -	$ 177,648	
6										
7										
8										

9 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
10 **FOR THE YEAR ENDING DECEMBER 31, 2023**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2023	Cross Reference
16	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
17										
18	**Non-Regulated Plant Depreciation**									
19	NRB Depreciation @ 0%	$ 1,054	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	NRB Depreciation @ 2.4%	176,594	2.40%	142,652	-	4,238	-	-	146,890	
21									-	
22	**Total**	$ 177,648		$ 142,652	$ -	$ 4,238	$ -	$ -	$ 146,890	

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 299,330	$ -	$ -	$ 2,453	$ -	$ 301,783	
3	Transmission Contributions	156,782	-	-	4,342	-	161,124	
4	Others	2,399	-	-	-	-	2,399	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 459,077	$ -	$ -	$ 6,795	$ -	$ 465,872	
7								
8	**Amortization**							
9	Distribution Contributions	$ (134,471)	$ -	$ -	$ (6,316)	$ -	$ (140,787)	
10	Transmission Contributions	(61,002)	-	-	(2,289)	-	(63,291)	
11	Others	(1,110)	-	-	(120)	-	(1,230)	
12	Biomethane	(301)	-	-	(28)	-	(329)	
13	**Total**	$ (196,884)	$ -	$ -	$ (8,753)	$ -	$ (205,637)	
14								
15	**Net CIAC**	$ 262,193	$ -	$ -	$ (1,958)	$ -	$ 260,235	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,753)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,725)			

NET SALVAGE CONTINUITY SCHEDULE Schedule 10
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	471-01	Distribution Land Rights	3,502	0.00%	146	-	-	146	
3			$ 3,502		$ 146	$ -	$ -	$ 146	
4									
5		**MANUFACTURED GAS / LOCAL STORAGE**							
6	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 1,714	0.00%	$ (22)	$ -	$ -	$ (22)	
7	442-00	Structures & Improvements (Tilbury)	100,809	0.68%	2,858	686	-	3,544	
8	443-00	Gas Holders - Storage (Tilbury)	180,974	1.12%	7,593	2,027	-	9,620	
9	448-11	Piping (Tilbury)	48,635	0.28%	707	136	-	843	
10	448-21	Pre-treatment (Tilbury)	38,752	0.50%	945	194	-	1,139	
11	448-31	Liquefaction Equipment (Tilbury)	94,779	0.57%	2,853	540	-	3,393	
12	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	1,580	228	-	1,808	
13	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	513	93	-	606	
14	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	1,298	222	-	1,520	
15	448-41	Send out Equipment(Tilbury)	7,746	0.28%	85	22	-	107	
16	448-51	Sub-station and Electric (Tilbury)	36,846	0.56%	1,066	206	-	1,272	
17	448-10	Piping (Mount Hayes)	12,455	0.28%	198	35	-	233	
18	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	835	146	-	981	
19	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	959	165	-	1,124	
20	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	384	66	-	450	
21	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	717	122	-	839	
22	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	108	18	-	126	
23			$ 740,576		$ 22,677	$ 4,906	$ -	$ 27,583	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 38,679	0.11%	$ 561	$ 43	$ -	$ 604	
3	463-00	Measuring Structures	20,274	0.62%	757	126	-	883	
4	464-00	Other Structures & Improvements	12,622	0.29%	148	37	-	185	
5	465-00	Mains	1,696,643	0.42%	38,828	7,126	(35)	45,919	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	1,030	200	-	1,230	
7	465-30	Mt Hayes - Mains	6,307	0.30%	117	19	-	136	
8	466-00	Compressor Equipment	203,229	0.07%	2,577	142	-	2,719	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	0.21%	73	17	-	90	
10	467-10	Measuring & Regulating Equipment	105,246	0.16%	1,177	168	-	1,345	
11	467-20	Telemetering	18,305	0.00%	(28)	-	-	(28)	
12	467-31	IP Intermediate Pressure Whistler	404	0.35%	5	1	-	6	
13	468-00	Communication Structures & Equipment	13,428	0.00%	401	-	-	401	
14			$ 2,182,102		$ 45,646	$ 7,879	$ (35)	$ 53,490	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (1,989)	$ -	$ -	$ (1,989)	
18	472-00	Structures & Improvements	63,261	0.52%	813	329	-	1,142	
19	473-00	Services	1,504,344	2.09%	86,754	31,440	(15,179)	103,015	
20	474-00	House Regulators & Meter Installations	158,627	3.37%	1,939	5,346	(1)	7,284	
21	474-02	Meters/Regulators Installations	237,903	0.00%	749	-	-	749	
22	475-00	Mains	2,228,759	0.50%	59,146	11,144	(2,048)	68,242	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	231,440	0.45%	5,401	1,041	-	6,442	
25	477-20	Telemetering	23,957	0.48%	329	115	-	444	
26	478-10	Meters	317,102	0.00%	2,788	-	-	2,788	
27			$ 4,771,464		$ 156,636	$ 49,415	$ (17,228)	$ 188,823	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 777	0.29%	$ 12	$ 2	$ -	$ 14	
31	475-10	Bio Gas Mains – Municipal Land	3,098	0.39%	50	12	-	62	
32	475-20	Bio Gas Mains – Private Land	398	0.39%	3	2	-	5	
33	418-20	Bio Gas Purification Upgrader	11,563	0.24%	148	28	-	176	
34	477-40	Bio Gas Reg & Meter Equipment	3,819	0.00%	(6)	-	-	(6)	
35	474-10	Bio Gas Reg & Meter Installations	770	1.44%	27	11	-	38	
36			$ 20,425		$ 234	$ 55	$ -	$ 289	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 10.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,373	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	0.00%	11	-	-	11	
4	476-40	NG Transportation LNG Foundations	1,049	0.00%	10	-	-	10	
5	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	0.00%	23	-	-	23	
6			$ 33,213		$ 43	$ -	$ -	$ 43	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 25,365	0.37%	$ (111)	$ 94	$ -	$ (17)	
10	482-20	Masonry Buildings	128,253	0.08%	1,202	103	-	1,305	
11	482-30	Leasehold Improvement	3,224	0.00%	(73)	-	-	(73)	
12	483-30	GP Office Equipment	3,408	0.00%	1	-	-	1	
13	483-40	GP Furniture	22,239	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	61,411	-3.70%	(2,714)	(2,272)	-	(4,986)	
15	485-10	Heavy Work Equipment	750	-0.67%	(26)	(5)	-	(31)	
16	485-20	Heavy Mobile Equipment	9,277	-1.80%	(1,009)	(167)	-	(1,176)	
17	486-00	Small Tools & Equipment	60,652	0.00%	51	-	-	51	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-20	Radio	19,365	0.00%	(7)	-	-	(7)	
20			$ 333,944		$ (2,782)	$ (2,247)	$ -	$ (5,029)	
21									
22		**Total**	$ 8,085,226		$ 222,600	$ 60,008	$ (17,263)	$ 265,345	
23		Less: Depreciation & Amortization Transferred to Biomethane BVA				(55)			
24		**Net Salvage Depreciation Expense**				$ 59,953			
25		Cross Reference	Schedule 6.2, Columns 3+4+5				Schedule 11.1, Line 5, Column 4		

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (49,582)	$ 44	$ -	$ -	$ -	$ 33,930	$ (9,161)	$ (24,769)	$ (37,154)	
3	Commodity Cost Reconciliation Account (CCRA)	175,424	-	(110,478)	29,829	-	-	-	94,775	135,100	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(42,404)	-	-	-	-	29,044	(7,842)	(21,202)	(31,803)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(82)	-	1,459	(394)	(484)	1,782	(481)	1,800	859	
6	SCP Mitigation Revenues Variance Account	325	-	-	-	(112)	-	-	213	269	
7	Pension & OPEB Variance	14,018	-	-	-	(5,154)	-	-	8,864	11,441	
8	BCUC Levies Variance	685	-	-	-	(685)	-	-	-	343	
9	FEFN - Gas Cost Reconciliation Account (GCRA)	44	(44)	-	-	-	-	-	-	-	
10	FEFN - Property Tax Variance	9	(9)	-	-	-	-	-	-	-	
11	FEFN - Interest Variance Deferral	(7)	7	-	-	-	-	-	-	-	
12		$ 98,430	$ (2)	$ (109,019)	$ 29,435	$ (6,435)	$ 64,756	$ (17,484)	$ 59,681	$ 79,055	
13											
14	**2. Rate Smoothing Accounts**										
15											
16	**3. Benefits Matching Accounts**										
17	Demand-Side Management (DSM)	$ 243,655	$ 61,086	$ 60,000	$ (16,200)	$ (41,608)	$ -	$ -	$ 306,933	$ 305,837	
18	NGV Conversion Grants	8	-	-	-	(3)	-	-	5	7	
19	Emissions Regulations	(26,708)	-	-	-	26,708	-	-	-	(13,354)	
20	On-Bill Financing Pilot Program	1	-	(1)	-	-	-	-	-	1	
21	Greenhouse Gas Reduction Regulation Incentives	24,308	-	4,700	(1,269)	(5,387)	-	-	22,352	23,330	
22	CNG and LNG Recoveries	(548)	-	(873)	236	548	-	-	(637)	(593)	
23	BCUC Initiated Inquiry Costs	121	-	100	(27)	(121)	-	-	73	97	
24	2017 Rate Design Application	272	-	-	-	(272)	-	-	-	136	
25	PGR Application and Preliminary Stage Development Costs	261	-	-	-	(151)	-	-	110	186	
26	Transportation Service Report	176	-	59	(16)	-	-	-	219	198	
27	2021 Generic Cost of Capital Proceeding	731	-	450	(122)	-	-	-	1,059	895	
28	City of Coquitlam Application Proceeding	129	-	-	-	(129)	-	-	-	65	
29		$ 242,406	$ 61,086	$ 64,435	$ (17,398)	$ (20,415)	$ -	$ -	$ 330,114	$ 316,805	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 4,974	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 4,237	$ 4,606	
3	Gas Asset Records Project	544	-	-	-	(266)	-	-	278	411	
4	Gains and Losses on Asset Disposition	4,521	-	-	-	(3,998)	-	-	523	2,522	
5	Net Salvage Provision/Cost	(222,599)	-	17,265	-	(60,008)	-	-	(265,342)	(243,971)	
6	PCEC Start Up Costs	568	-	-	-	(44)	-	-	524	546	
7	2022 Long Term Gas Resource Plan Application	822	-	350	(95)	-	-	-	1,077	950	
8	2020–2024 MRP Application	271	-	-	-	(135)	-	-	136	204	
9	2021 Renewable Gas Program Comprehensive Review	1,061	-	1,551	(419)	-	-	-	2,193	1,627	
10	GCU Preliminary Stage Development Costs	776	-	-	-	(259)	-	-	517	647	
11	Transmission Integrity Management Capabilities	-	12,604	-	-	(2,521)	-	-	10,083	11,344	
12	Annual Review of 2020-2024 Rates	98	-	160	(43)	(98)	-	-	117	108	
13	FEFN - Common Rates and 2022 Revenue Requirement Application Costs	179	-	-	-	(179)	-	-	-	90	
14	FEFN - Billing System Costs for FEFN Rate Changes	1	(1)	-	-	-	-	-	-	-	
15		$ (208,784)	$ 12,603	$ 19,326	$ (557)	$ (68,245)	$ -	$ -	$ (245,657)	$ (220,916)	
16											
17	**4. Retroactive Expense Accounts**										
18											
19	**5.Other Accounts**										
20	Pension & OPEB Funding	$ (240,902)	$ -	$ 2,345	$ -	$ -	$ -	$ -	$ (238,557)	$ (239,730)	
21	US GAAP Pension & OPEB Funded Status	106,710	-	-	-	-	-	-	106,710	106,710	
22	BVA Balance Transfer	500	18,587	-	-	-	(26,146)	7,059	-	9,544	
23	COVID-19 Customer Recovery Fund	1,736	-	-	-	(578)	-	-	1,158	1,447	
24	Stargas Assets Acquisition Deferral Account	-	106	-	-	(106)	-	-	-	53	
25	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
26	FEFN - Transitional Balance	-	3	-	-	(3)	-	-	-	2	
27		$ (131,956)	$ 18,696	$ 2,345	$ -	$ (687)	$ (26,146)	$ 7,059	$ (130,689)	$ (121,974)	
28											
29	**Total**	$ 96	$ 92,383	$ (22,913)	$ 11,480	$ (95,782)	$ 38,610	$ (10,425)	$ 13,449	$ 52,970	
30	Less: Net Salvage Amortization Transferred to Biomethane BVA					55					
31	**Net Rate Base Deferred Amortization Expense**					$ (95,727)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 12

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ 25,255	$ (18,587)	$ -	$ -	$ -	$ -	$ -	$ 6,668	$ 6,668	
3	Flowthrough (2020-2024)	19,006	-	506	-	(19,512)	-	-	-	9,503	
4	Marketer Cost Variance	(48)	-	66	(18)	-	-	-	-	(24)	
5		$ 44,213	$ (18,587)	$ 572	$ (18)	$ (19,512)	$ -	$ -	$ 6,668	$ 16,147	
6	**2. Rate Smoothing Accounts**										
7	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8	FEFN - Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	(93)	-	-	-	-	258	(70)	95	1	
9		$ (93)	$ -	$ -	$ -	$ -	$ 258	$ (70)	$ 95	$ 1	
10											
11	**3. Benefits Matching Accounts**										
12	Demand-Side Management (DSM) - Non Rate Base	$ 61,086	$ (61,086)	$ 82,620	$ (21,871)	$ -	$ -	$ -	$ 60,749	$ 30,375	
13	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
14	Transmission Integrity Management Capabilities	12,029	(12,604)	142	(46)	-	-	-	(479)	(527)	
15	Clean Growth Innovation Fund	(6,739)	-	2,078	(675)	-	(5,158)	1,393	(9,101)	(7,920)	
16		$ 63,978	$ (73,690)	$ 84,840	$ (22,592)	$ -	$ (5,158)	$ 1,393	$ 48,771	$ 19,530	
17											
18	**4. Retroactive Expense Accounts**										
19											
20	**5.Other Accounts**										
21	Mark to Market - Hedging Transactions	$ 76	$ -	$ -	$ -	$ -	$ -	$ -	$ 76	$ 76	
22	MRP Earnings Sharing Account	(268)	-	(7)	-	275	-	-	-	(134)	
23	Stargas Assets Acquisition Deferral Account	106	(106)	-	-	-	-	-	-	-	
24	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
25	FEFN - Right-Of-Way Agreement	163	-	9	-	-	-	-	172	168	
26		$ 77	$ (106)	$ 2	$ -	$ 275	$ -	$ -	$ 248	$ 110	
27											
28											
29	**Total Non Rate Base Deferral Accounts**	$ 108,175	$ (92,383)	$ 85,414	$ (22,610)	$ (19,237)	$ (4,900)	$ 1,323	$ 55,782	$ 35,788	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 19,040	$ 19,750	$ 710	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,559	1,894	335	
6	Employee Withholdings	(6,367)	(6,888)	(521)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,725	5,869	4,144	
10	Gas In Storage	50,364	90,540	40,176	
11	Inventories - Materials and Supplies	2,250	2,608	358	
12	Refundable Contributions	(318)	(312)	6	
13					
14	Total	$ 68,253	$ 113,461	$ 45,208	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 1,257,965	40.3	$ 50,695,990		
4	Commercial Tariff Revenue	697,400	37.8	26,361,720		
5	Industrial Tariff Revenue	223,440	47.7	10,658,069		
6	Bypass and Special Rates	70,312	37.6	2,643,730		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,385	53.8	182,113		
10	Application Charges	2,020	39.0	78,780		
11	Other Utility Income	36,613	39.0	1,427,907		
12						
13	Total	$ 2,291,135		$ 92,048,309	40.2	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 1,170,773	(40.0)	$ (46,830,920)		
17	Operating and Maintenance	292,666	(31.8)	(9,306,779)		
18	Property Taxes	79,144	(1.3)	(102,887)		
19	Operating Fees	14,114	(352.9)	(4,980,735)		
20	Carbon Tax	501,835	(30.7)	(15,406,335)		
21	GST	38,791	(39.7)	(1,539,988)		
22	PST	35,355	(45.8)	(1,619,263)		
23	Income Tax	51,748	(15.2)	(786,570)		
24						
25	Total	$ 2,184,425		$ (80,573,477)	(36.9)	
26						
27	Net Lag (Lead) Days				3.3	
28	Total Expenses				$ 2,184,425	
29						
30	Cash Working Capital				$ 19,750	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 15

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (520,816)	$ (567,344)	$ (46,528)	
2	Tax Gross Up	(192,631)	(209,840)	(17,209)	
3	DIT Liability/Asset - End of Year	$ (713,447)	$ (777,184)	$ (63,737)	
4	DIT Liability/Asset - Opening Balance	(666,166)	(717,706)	(51,540)	
5					
6	DIT Liability/Asset - Mid Year	$ (689,807)	$ (747,445)	$ (57,638)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 16

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	156,232	160,101		160,101	3,868	
3	Transportation Volume (TJ)	77,825	61,672		61,672	(16,152)	
4		234,057	221,773	-	221,773	(12,284)	Schedule 17, Line 24, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,552,577	$ 2,093,361	$ -	$ 2,093,361	$ 540,784	
8	Deficiency (Surplus)	-	-	68,957	68,957	68,957	
9	Transportation	98,654	81,164	-	81,164	(17,490)	
10	Deficiency (Surplus)	-		5,635	5,635	5,635	
11	Total	1,651,231	2,174,525	74,592	2,249,117	597,886	Schedule 19, Line 30, Column 8
12				-			
13	**COST OF ENERGY**	647,970	1,170,773	-	1,170,773	522,803	Schedule 18, Line 24, Column 3
14							
15	**MARGIN**	1,003,261	1,003,752	74,592	1,078,344	75,083	
16							
17	**EXPENSES**						
18	O&M Expense (net)	276,620	292,666	-	292,666	16,046	Schedule 20, Line 28, Column 4
19	Depreciation & Amortization	308,177	326,852	-	326,852	18,675	Schedule 21, Line 15, Column 3
20	Property Taxes	73,397	79,144	-	79,144	5,747	Schedule 22, Line 8, Column 3
21	Other Revenue	(41,636)	(42,018)	-	(42,018)	(382)	Schedule 23, Line 12, Column 3
22	Utility Income Before Income Taxes	386,703	347,108	74,592	421,700	34,997	
23							
24	Income Taxes	52,212	31,613	20,135	51,748	(464)	Schedule 24, Line 13, Column 3
25							
26	**EARNED RETURN**	$ 334,491	$ 315,495	$ 54,457	$ 369,952	$ 35,461	Schedule 26, Line 5, Column 7
27							
28	**UTILITY RATE BASE**	$ 5,409,207	$ 5,942,654		$ 5,943,434	$ 534,227	Schedule 2, Line 31, Column 3
29	**RATE OF RETURN ON UTILITY RATE BASE**	6.18%	5.31%		6.23%	0.04%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	81,494.4	82,889.5	1,395.1	
4	Commercial				
5	Rate Schedule 2	29,000.0	29,204.3	204.3	
6	Rate Schedule 3	24,886.2	25,770.1	883.9	
7	Rate Schedule 23	4,125.4	3,903.8	(221.6)	
8	Industrial				
9	Rate Schedule 4	159.5	166.1	6.6	
10	Rate Schedule 5	9,420.4	10,826.9	1,406.5	
11	Rate Schedule 6	20.8	20.9	0.1	
12	Rate Schedule 7	6,601.1	6,004.2	(596.9)	
13	Rate Schedule 22 - Firm Service	10,379.2	10,378.3	(0.9)	
14	Rate Schedule 22 - Interruptible Service	16,533.0	17,144.2	611.2	
15	Rate Schedule 25	9,163.8	8,303.3	(860.5)	
16	Rate Schedule 27	4,510.5	4,289.1	(221.4)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	10,916.5	11,945.6	1,029.1	
19	Rate Schedule 25	1,017.5	951.3	(66.2)	
20	Rate Schedule 46	4,650.0	5,218.5	568.5	
21	Byron Creek	8.7	11.6	2.9	
22	BC Hydro IG	16,425.0	-	(16,425.0)	
23	VIGJV	4,745.0	4,745.0	-	
24	Total	234,057.0	221,772.7	(12,284.3)	
25					
26	**REVENUE AT EXISTING RATES**				
27	Residential				
28	Rate Schedule 1	$ 935,165	$ 1,211,962	$ 276,797	
29	Commercial				
30	Rate Schedule 2	275,898	370,328	94,430	
31	Rate Schedule 3	202,044	290,528	88,484	
32	Rate Schedule 23	16,452	15,538	(914)	
33	Industrial				
34	Rate Schedule 4	985	1,525	540	
35	Rate Schedule 5	61,335	103,635	42,300	
36	Rate Schedule 6	131	203	72	
37	Rate Schedule 7	35,373	51,121	15,748	
38	Rate Schedule 22 - Firm Service	7,897	8,431	534	
39	Rate Schedule 22 - Interruptible Service	20,111	21,201	1,090	
40	Rate Schedule 25	24,222	22,038	(2,184)	
41	Rate Schedule 27	8,088	7,703	(385)	
42	Bypass and Special Rates				
43	Rate Schedule 22 - Firm Service	794	799	5	
44	Rate Schedule 25	426	424	(2)	
45	Rate Schedule 46	41,646	64,059	22,413	
46	Byron Creek	119	134	15	
47	BC Hydro IG	15,735	-	(15,735)	
48	VIGJV	4,810	4,896	86	
49	Total	$ 1,651,231	$ 2,174,525	$ 523,294	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 346,101	$ 614,049	$ 267,948	
4	Commercial				
5	Rate Schedule 2	123,827	217,315	93,488	
6	Rate Schedule 3	100,657	185,898	85,241	
7	Rate Schedule 23	70	147	77	
8	Industrial				
9	Rate Schedule 4	586	1,133	547	
10	Rate Schedule 5	34,441	73,578	39,137	
11	Rate Schedule 6	59	127	68	
12	Rate Schedule 7	24,251	40,943	16,692	
13	Rate Schedule 22 - Firm Service	258	571	313	
14	Rate Schedule 22 - Interruptible Service	200	466	266	
15	Rate Schedule 25	156	313	157	
16	Rate Schedule 27	77	162	85	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	185	450	265	
19	Rate Schedule 25	17	36	19	
20	Rate Schedule 46	17,085	35,585	18,500	
21	Byron Creek	-	-	-	
22	BC Hydro IG	-	-	-	
23	VIGJV	-	-	-	
24	Total	$ 647,970	$ 1,170,773	$ 522,803	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 19

Line No.	Particulars	2022 Approved Margin	2023 Forecast: Margin at 2022 Approved Rates	2023 Forecast: Effective Increase	2023 Forecast: Margin at Revised Rates	2023 Forecast: Revenue at 2022 Approved Rates	2023 Forecast: Effective Increase	2023 Forecast: Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 589,064	$ 597,913	$ 46,003	$ 643,916	$ 1,211,962	$ 46,003	$ 1,257,965	977,501	82,889.5	
4	Commercial										
5	Rate Schedule 2	152,071	153,013	11,772	164,785	370,328	11,772	382,100	90,632	29,204.3	
6	Rate Schedule 3	101,387	104,630	8,050	112,680	290,528	8,050	298,578	7,049	25,770.1	
7	Rate Schedule 23	16,382	15,391	1,184	16,575	15,538	1,184	16,722	701	3,903.8	
8	Industrial										
9	Rate Schedule 4	399	392	30	422	1,525	30	1,555	18	166.1	
10	Rate Schedule 5	26,894	30,057	2,313	32,370	103,635	2,313	105,948	632	10,826.9	
11	Rate Schedule 6	72	76	6	82	203	6	209	13	20.9	
12	Rate Schedule 7	11,122	10,178	783	10,961	51,121	783	51,904	45	6,004.2	
13	Rate Schedule 22 - Firm Service	7,639	7,860	605	8,465	8,431	605	9,036	9	10,378.3	
14	Rate Schedule 22 - Interruptible Service	19,911	20,735	1,595	22,330	21,201	1,595	22,796	29	17,144.2	
15	Rate Schedule 25	24,066	21,725	1,671	23,396	22,038	1,671	23,709	272	8,303.3	
16	Rate Schedule 27	8,011	7,541	580	8,121	7,703	580	8,283	70	4,289.1	
17	Total Non-Bypass	$ 957,018	$ 969,511	$ 74,592	$ 1,044,103	$ 2,104,213	$ 74,592	$ 2,178,805	1,076,971	198,900.7	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 609	$ 349		$ 349	$ 799		$ 799	6	11,945.6	
22	Rate Schedule 25	409	388		388	424		424	3	951.3	
23	Rate Schedule 46	24,561	28,474		28,474	64,059		64,059	21	5,218.5	
24	Byron Creek	119	134		134	134		134	1	11.6	
25	BC Hydro IG	15,735	-		-	-		-	-	-	
26	VIGJV	4,810	4,896		4,896	4,896		4,896	1	4,745.0	
27	Total Bypass & Special	$ 46,243	$ 34,241	$ -	$ 34,241	$ 70,312	$ -	$ 70,312	32	22,872.0	
28											
29											
30	Total	$ 1,003,261	$ 1,003,752	$ 74,592	$ 1,078,344	$ 2,174,525	$ 74,592	$ 2,249,117	1,077,003	221,772.7	
31											
32	**Effective Increase**			7.69%			3.54%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 269			
3	2023 Net Inflation Factor	3.932%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 280			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	1,066,294			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 298,562			Line 4 x Line 6 / 1000
9					
10	2021 Average Customer True-up	740			
11					
12	2023 Inflation Indexed O&M	$ 299,302		$ 299,302	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 9,577		
16	Insurance		12,242		
17	Biomethane O&M		5,237		
18	NGT O&M		1,937		
19	Variable LNG Production		7,859		
20	Integrity O&M		8,000		
21	Renewable Gas Development		2,000		
22	BCUC fees		8,493		
23	Sub-total		$ 55,345	55,345	Sum of Lines 15 through 22
24					
25	**Total Gross O&M**			$ 354,647	Line 12 + Line 23
26	O&M Transferred to Biomethane BVA			(5,237)	
27	Capitalized Overhead			(56,744)	-16 % x Line 25
28	**Net O&M Expense**			$ 292,666	Sum of Lines 25 through 27

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 210,971	$ 223,974	$ 13,003	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(765)	(821)	(56)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,176)	(2,540)	(364)	Schedule 7.2, Line 37, Column 7
5		208,030	220,613	12,583	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 98,731	$ 95,782	$ (2,949)	Schedule 11.1, Line 29, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(48)	(55)	(7)	Schedule 11.1, Line 30, Column 6
10	Non-Rate Base Deferrals	10,064	19,237	9,173	Schedule 12, Line 29, Column 6
11	CIAC	(8,628)	(8,753)	(125)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		100,147	106,239	6,092	
14					
15	Total	$ 308,177	$ 326,852	$ 18,675	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 22

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 60,136	$ 62,913	$ 2,777	
2	1% In-Lieu of Municipal Taxes	13,368	16,323	2,955	
3					
4	Total	$ 73,504	$ 79,236	$ 5,732	
5					
6	Total Property Tax Expense per Line 4	$ 73,504	$ 79,236		
7	Less: Property Tax Transferred to Biomethane BVA	(107)	(92)		
8	**Net Property Tax Expense**	$ 73,397	$ 79,144		

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,704	$ 3,385	$ 681	
2	Application Charge	2,013	2,020	7	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	13,410	13,286	(124)	
6	NGT Tanker Rental Revenue	928	926	(2)	
7	NGT Overhead and Marketing Recovery	283	273	(10)	
8	Biomethane Other Revenue	986	512	(474)	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,957	3,261	304	
11					
12	Total	$ 41,636	$ 42,018	$ 382	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 334,491	$ 369,952	$ 35,461	Schedule 16, Line 26, Column 5
2	Deduct: Interest on Debt	(152,268)	(169,733)	(17,465)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(41,057)	(60,308)	(19,251)	Line 36
4	Accounting Income After Tax	$ 141,166	$ 139,911	$ (1,255)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 193,378	$ 191,659	$ (1,719)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 52,212	$ 51,748	$ (464)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 52,212	$ 51,748	$ (464)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	208,030	220,613	12,583	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	108,747	114,964	6,217	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,259	984	(275)	
22	Vehicles: Interest & Capitalized Depreciation	2,181	2,545	364	
23	Pension Expense	11,137	10,167	(970)	
24	OPEB Expense	7,642	5,020	(2,622)	
25					
26	Deductions:				
27	Capital Cost Allowance	(298,674)	(330,330)	(31,656)	Schedule 25, Line 23, Column 6
28	CIAC Amortization	(8,600)	(8,725)	(125)	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs	(1,816)	(1,984)	(168)	
30	Vehicle Lease Payment	(142)	(73)	69	
31	Pension Contributions	(13,739)	(14,361)	(622)	
32	OPEB Contributions	(3,206)	(3,171)	35	
33	Overheads Capitalized Expensed for Tax Purposes	(26,664)	(28,262)	(1,598)	
34	Removal Costs	(24,653)	(17,265)	7,388	Schedule 11.1, Line 5, Column 4
35	Major Inspection Costs	(3,759)	(11,630)	(7,871)	
36	Total	$ (41,057)	$ (60,308)	$ (19,251)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,015,641	$ (1)	$ -	$ (40,625)	$ 975,015
2	1(b)	6%	7,484	14,625	7,312	(1,765)	20,344
3	2	6%	76,908	-	-	(4,613)	72,295
4	3	5%	1,533	-	-	(77)	1,456
5	6	10%	214	-	-	(21)	193
6	7	15%	20,105	1,530	765	(3,360)	18,275
7	8	20%	30,596	10,962	5,481	(9,408)	32,150
8	10	30%	15,237	9,145	4,573	(8,687)	15,695
9	10.1	30%	90	-	-	(27)	63
10	12	100%	-	23,036	-	(23,036)	-
11	13	manual	2,778	2,949	1,474	(478)	5,249
12	14.1 (pre 2017)	7%	14,202	-	-	(994)	13,208
13	14.1 (post 2016)	5%	5,062	-	-	(254)	4,808
14	17	8%	885	-	-	(71)	814
15	38	30%	1,050	1,720	860	(1,088)	1,682
16	43.2	50%	98	31,224	-	(31,273)	49
17	47	8%	140,734	-	-	(11,259)	129,475
18	47 (LNG Equip - post Feb 2015)	8%	148,233	21,379	10,690	(14,424)	155,188
19	49	8%	493,864	36,692	18,347	(43,912)	486,644
20	50	55%	3,474	11,515	5,758	(11,411)	3,578
21	51	6%	1,716,521	228,394	114,197	(123,547)	1,821,368
22							
23	Total		$ 3,694,709	$ 393,170	$ 169,457	$ (330,330)	$ 3,757,549
24							
25	* Note - Accelerated Investment Incentive Property						

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 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	$ 149,765	$ 3,402,586	57.25%	4.70%	2.69%	$ 159,754	$ 9,989	Schedule 27, Lines 27&29, Columns 5&6&7
2	Short Term Debt	2,503	252,626	4.25%	3.95%	0.17%	9,979	7,476	
3	Common Equity	182,223	2,288,222	38.50%	8.75%	3.37%	200,219	17,996	
4									
5	Total	$ 334,491	$ 5,943,434	100.00%		6.22%	$ 369,952	$ 35,461	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Ref
	(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	130,985	131,826	2.644%	3,485	
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	3.822%	5,733	
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 - Series 31	December 7, 2018	December 7, 2048	198,351	200,000	3.897%	7,794	
15	2019 Medium Term Debt Issue - Series 32	August 9, 2019	August 9, 2049	198,500	200,000	2.857%	5,714	
16	2020 Medium Term Debt Issue - Series 33	July 13, 2020	July 13, 2050	198,392	200,000	2.579%	5,158	
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	148,984	150,000	2.495%	3,743	
18	2022 Medium Term Debt Issue	October 1, 2022	October 1, 2052	198,000	200,000	4.864%	9,728	
19	2023 Medium Term Debt Issue	October 1, 2023	October 1, 2053	297,000	75,616	4.763%	3,602	
20								
21	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
22	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
23								
24								
25	Vehicle Lease Obligation				144	3.472%	5	
26								
27	Total				$ 3,402,586		$ 159,754	
28								
29	Average Embedded Cost					4.70%		
30								
31	* Interest Rate is Effective Interest Rate as it includes amortization of debt issue costs							

Appendix C

2023 COSA STUDY O&M ALLOCATION PERCENTAGES

FORTISBC ENERGY INC. **Appendix C**

2023 Revenue Requirement O&M Split

Line		2023	Percentage
1	**Operating & Maintenance Expense**		
2	Distribution Supervision	$ 17,628.3	4.97%
3	Operation Centre - Distribution	9,037.8	2.55%
4	Preventative Maintenance - Distribution	3,409.1	0.96%
5	Operations - Distribution	9,356.2	2.64%
6	Emergency Management - Distribution	6,819.9	1.92%
7	Field Training - Distribution	4,226.5	1.19%
8	Meter Exchange - Distribution	3,544.4	1.00%
9	Corrective - Distribution	9,979.4	2.81%
10	Account Services - Distribution	1,367.2	0.39%
11	Bad Debt Management - Distribution	1,338.5	0.38%
12	**Distribution Total**	**$66,707.3**	
13			
14	Transmission Supervision	3,134.3	0.88%
15	Pipeline / Right of Way Operations	22,338.9	6.30%
16	Compression Operations	7,218.7	2.04%
17	Measurement Control Operations	1,549.7	0.44%
18	Pipeline / Right of Way - Maintenance	888.6	0.25%
19	Compression - Maintenance	1,233.4	0.35%
20	Measurement Control Operations	125.5	0.04%
21	**Transmission Total**	**$36,489.2**	
22			
23			
24	LNG Plant Operations	18,101.8	5.10%
25	LNG Plant Maintenance	211.9	0.06%
26	**LNG Plant Total - Tilbury**	**$18,313.7**	
27			
28			
29	Meter Reading	14,408.7	4.06%
30	**Meter Reading Total**	**$14,408.7**	
31			
32	Energy Supply & Resource Development	3,230.8	0.91%
33	Gas Control	3,056.8	0.86%
34	**Energy Supply & Resource Development Total**	**$6,287.6**	
35			
36	Facilities Management	11,249.7	3.17%
37	Supply Chain	6,332.9	1.79%
38	Measurement	6,848.2	1.93%
39	Property Services	1,695.0	0.48%
40	System Planning	6,630.5	1.87%
41	Engineering	12,339.8	3.48%
42	Project Management	2,466.8	0.70%
43	**General Operations Total**	**$47,562.9**	

FORTISBC ENERGY INC. **Appendix C**

2023 Revenue Requirement O&M Split

		2023	Percentage
44			
45	Energy Solutions & External Relations Supervision	1,174.7	0.33%
46	Energy Solutions	12,478.3	3.52%
47	Energy Efficiency	899.8	0.25%
48	Corporate Communications & External Relations	11,460.5	3.23%
49	Resource Plan, Market & Business Development	12,742.0	3.59%
50	**Energy Solutions & External Relations Total**	**$38,755.4**	
51			
52	Customer Service Supervision	1,514.0	0.43%
53	Customer Assistance	11,746.4	3.31%
54	Customer Billing	11,534.2	3.25%
55	Credit & Collections	3,504.4	0.99%
56	Customer Operations	4,901.6	1.38%
57	**Customer Care Total**	**$33,200.7**	
58			
59	Information Systems Supervision	2,640.7	0.74%
60	Application Management	19,259.3	5.43%
61	Infrastructure Management	9,172.8	2.59%
62	**Business & IT Services Total**	**$31,072.7**	
63			
64	Administration & General	2,384.6	0.67%
65	Shared Services Agreement	6,653.3	1.88%
66	Retiree Benefits	-	0.00%
67	Legal	2,034.4	0.57%
68	Internal Audit	1,296.2	0.37%
69	Risk Management/Insurance	12,240.8	3.45%
70	Environment Health & Safety	7,235.2	2.04%
71	Financial & Regulatory Services	19,994.0	5.64%
72	Human Resources	10,010.2	2.82%
73	**Administration & General Total**	**$61,848.7**	
74			
75	**Gross Operating & Maintenance Expense**	**$354,647.0**	100.00%
76			
77	O&M Transferred to the BVA	(5,237.0)	
78	Capitalized Overhead	(56,744.0)	
79			
80	**Net Operating & Maintenance Expense**	**$292,666.0**	

Appendix D

2023 COSA FINANCIAL SCHEDULES
(INITIAL AND FINAL RESULTS)

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023 **Schedule 1**
Summary ($000s)

Line	Particular	Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
1	**REVENUE**												
2	Delivery Margin at 2023 Rates incl. Known & Measureable Changes		1,030,693	643,916	164,785	422	82	3,184	8,440	5,762	129,255	55,766	19,082
3	Total Cost of Gas (incl. imputed amounts for RS23, 25, and 27[1],[2]		1,247,531	614,049	217,315	1,133	127	80	289	282	214,059	130,006	70,191
4	**Revenue at 2023 Rates incl. Known & Measurable changes**	**Line 2 + Line 3**	**2,278,224**	**1,257,965**	**382,100**	**1,555**	**209**	**3,264**	**8,729**	**6,044**	**343,314**	**185,772**	**89,273**
5													
6	**COST OF SERVICE**												
7	Allocated Delivery Margin incl. Known & Measureable Changes		1,054,438	693,491	176,387	127	92	2,955	8,474	5,886	118,959	44,958	3,108
8	Total Cost of Gas (incl. imputed amounts for RS23, 25, and 27	Line 3	1,247,531	614,049	217,315	1,133	127	80	289	282	214,059	130,006	70,191
9	**Total Utility Allocated Cost of Service**	**Line 7 + Line 8**	**2,301,968**	**1,307,540**	**393,702**	**1,260**	**219**	**3,035**	**8,763**	**6,168**	**333,017**	**174,964**	**73,299**
10													
11	**SURPLUS / (DEFICIT)**												
12	Total Surplus / (Deficit)	Line 4 - Line 9	(23,744)										
13	% Increase to Equal Allocated Costs	-Line 12 / Line 2	2.30%										
14													
15	**REVENUE (Adjusted to equal Cost of Service)**												
16	Adjusted Delivery Margin at 2023 Rates incl. Known & Measureable Changes	Line 2 x (1 + Line 13)	1,054,438	658,750	168,581	432	84	3,257	8,634	5,894	132,233	57,051	19,522
17	Total Cost of Gas (incl. imputed amounts for RS23, 25, and 27	Line 3	1,247,531	614,049	217,315	1,133	127	80	289	282	214,059	130,006	70,191
18	**Adjusted Revenue at 2023 Rates incl. Known & Measurable changes**	**Line 16 + Line 17**	**2,301,968**	**1,272,799**	**385,896**	**1,565**	**211**	**3,337**	**8,923**	**6,176**	**346,292**	**187,057**	**89,712**
19													
20	**REVENUE TO COST RATIO (BASELINE)**												
21	Revenue to Cost Ratio before Rebalancing[2]	**Line 18 / Line 9**	**100.0%**	**97.3%**	**98.0%**	**124.1%**	**96.2%**	**110.0%**	**101.8%**	**100.1%**	**104.0%**	**106.9%**	**122.4%**
22													
23	**REVENUE REBALANCING**												
24	Delivery Margin Rebalancing		-	4,519	145	(46)	-	(151)	-	-	(145)	(3,344)	(978)
25													
26	Total Rebalanced Delivery Margin	Line 16 + Line 24	1,054,438	663,269	168,726	385	84	3,106	8,634	5,894	132,088	53,706	18,544
27	Total Cost of Gas (incl. imputed amounts for RS23, 25, and 27	Line 3	1,247,531	614,049	217,315	1,133	127	80	289	282	214,059	130,006	70,191
28	**Total Rebalanced Revenue**	**Line 26 + Line 27**	**2,301,968**	**1,277,318**	**386,041**	**1,518**	**211**	**3,187**	**8,923**	**6,176**	**346,147**	**183,712**	**88,734**
29													
30	**PROPOSED REVENUE TO COST RATIO**												
31	Margin to Cost Ratio incl. Known and Measurable Changes	Line 26 / Line 7	100.0%	95.6%	95.7%	302.5%	91.0%	105.1%	101.9%	100.1%	111.0%	119.5%	596.6%
32	**Revenue to Cost Ratio incl. Known and Measurable Changes**	**Line 28 / Line 9**	**100.0%**	**97.7%**	**98.1%**	**120.5%**	**96.2%**	**105.0%**	**101.8%**	**100.1%**	**103.9%**	**105.0%**	**121.1%**
33													
34													

35 **Note:**
36 1. Includes the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Rates 23, 25 and 27 are T-Service thus do not have commodity and midstream charges.
37 2. Includes UAF allocation to rate classes.
38 3. Rate 4 is a seasonal service and Rate 7/27 are interruptible customer classes. Their rates are not set based on their allocated costs.
39 These rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023
COST OF SERVICE FUNCTIONALIZATION ($000s)

Schedule 2

Line	Particular	Cross Reference	TOTAL	Gas Supply Operations	LNG Storage Tilbury BASE	LNG Storage Mt. Hayes	LNG Tilbury 1A	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense		294,792	4,042	10,922	5,048	10,143	57,268	119,146	44,322	43,902
2	Property & Sundry Taxes		79,490	-	492	1,077	3,418	26,425	48,078	-	-
3	Depreciation Expense		216,626	-	2,231	6,627	12,215	61,796	133,758	-	-
4	Amortization Expense		116,361	-	822	1,705	4,843	18,959	74,645	14,903	484
5	Other Operating Revenue		(88,828)	-	-	(18,039)	(28,474)	(32,134)	(6,796)	-	(3,385)
6	Income Tax		51,486	820	403	1,245	3,746	15,855	27,228	2,448	(259)
7	Earned Return		384,509	6,122	3,008	9,301	27,977	118,406	203,347	18,283	(1,934)
8	**Total Cost of Service Margin[1]**	**Schedule 1, Line 7**	**1,054,438**	**10,984**	**17,878**	**6,963**	**33,869**	**266,575**	**599,406**	**79,955**	**38,808**
9											
10	Cost of Gas (Commodity & Midstream)[2]	Sch 1, Line 8 (Excl. Imputed Amount)	1,134,316	1,134,316	-	-	-	-	-	-	-
11	**Total Utility Revenue Requirement**	**Line 8 + Line 10**	**2,188,754**	**1,145,300**	**17,878**	**6,963**	**33,869**	**266,575**	**599,406**	**79,955**	**38,808**
12											
13											
14	**Note:**										
15	1. Include known and measureable changes										
16	2. Exclude the imputed Cost of Gas for Rates 23, 25 and 27 which totaled to $113,214. See Note 1 of Schedule 1										

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023
RATE BASE FUNCTIONALIZATION ($000s)

Schedule 3

Line	Particular	Cross Reference	TOTAL	Gas Supply Operations	LNG Storage Tilbury BASE	LNG Storage Mt. Hayes	LNG Tilbury 1A	Transmission	Distribution	Marketing	Customer Accounting
1	Plant in Service										
2	Total Gross Plant		8,760,941	-	98,233	224,133	508,936	2,745,469	5,184,170	-	-
3	Total Accumulated Depreciation		(2,445,377)	-	(41,128)	(66,178)	(44,443)	(760,302)	(1,533,325)	-	-
4	Total Net Plant	Line 2 + Line 3	6,105,840	-	54,754	152,589	452,310	1,919,444	3,526,743	-	-
5											
6	Contribution in Aid of Construction										
7	Total Gross CIAC		(461,909)	-	-	-	-	(161,352)	(300,557)	-	-
8	Total Accumulated Amortization		200,946	-	-	-	-	63,317	137,629	-	-
9	Total Net CIAC	Line 7 + Line 8	(260,963)	-	-	-	-	(98,035)	(162,928)	-	-
10											
11	Adjustment for timing for Capital Additions		122,435	-	1,373	3,132	7,112	38,368	72,449	-	-
12	Capital Work in Progress, No AFUDC		42,846	-	480	1,096	2,489	13,427	25,354	-	-
13	Unamortized Deferred Charges		42,640	97,946	(8,479)	(8,023)	(14,330)	(75,318)	(210,704)	292,490	(30,943)
14	Working Capital		113,639	10,522	115	81	190	97,493	4,402	432	403
15	**Total Utility Rate Base**	**Sum of Line 4, 9, 11 to 14**	**6,166,437**	**108,468**	**48,243**	**148,876**	**447,772**	**1,895,379**	**3,255,316**	**292,922**	**(30,540)**
16											

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023

Schedule 4

COST OF SERVICE CLASSIFICATION ($000s)

Line	Particular	Cross Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
1	**Operationg & Maintenance Expense**												
2	Energy		4,042	2,177	749	4	1	-	-	-	657	292	162
3	Demand		131,464	70,390	26,279	1	6	584	1,467	892	22,602	9,206	36
4	Customer		159,286	123,218	23,459	55	18	225	534	472	7,421	2,863	1,021
5	**Total**	**Line 2 + 3 + 4**	**294,792**	**195,784**	**50,486**	**61**	**25**	**809**	**2,001**	**1,364**	**30,681**	**12,361**	**1,220**
6													
7	**Property & Sundry Taxes**												
8	Energy		-	-	-	-	-	-	-	-	-	-	-
9	Demand		45,835	24,247	9,238	0	2	207	537	326	8,003	3,264	10
10	Customer		33,656	27,839	4,137	5	4	20	45	53	1,222	254	77
11	**Total**	**Line 8 + 9 + 10**	**79,490**	**52,087**	**13,375**	**5**	**6**	**227**	**582**	**379**	**9,225**	**3,518**	**88**
12													
13	**Depreciation Expense**												
14	Energy		-	-	-	-	-	-	-	-	-	-	-
15	Demand		119,859	64,652	23,684	2	6	522	1,556	946	20,224	8,226	40
16	Customer		105,492	83,837	14,640	19	17	84	275	307	4,939	1,050	325
17	**Total**	**Line 14 + 15 + 16**	**225,351**	**148,489**	**38,324**	**20**	**23**	**606**	**1,832**	**1,253**	**25,163**	**9,276**	**365**
18													
19	**CIAC Amortization**												
20	Energy		-	-	-	-	-	-	-	-	-	-	-
21	Demand		(5,572)	(2,813)	(1,178)	-	(0)	(27)	(44)	(26)	(1,052)	(431)	-
22	Customer		(3,153)	(1,520)	(1,116)	(1)	(1)	(6)	(36)	(33)	(344)	(72)	(22)
23	**Total**	**Line 20 + 21 + 22**	**(8,725)**	**(4,334)**	**(2,294)**	**(1)**	**(1)**	**(33)**	**(80)**	**(60)**	**(1,397)**	**(503)**	**(22)**
24													
25	**Amortization Expense**												
26	Energy		41,608	26,132	5,793	13	2	172	621	606	5,887	1,549	833
27	Demand		68,190	36,945	13,430	1	6	295	879	536	11,427	4,644	26
28	Customer		6,563	3,427	2,446	(5)	5	(17)	125	125	788	(220)	(110)
29	**Total**	**Line 26 + 27 + 28**	**116,361**	**66,504**	**21,669**	**9**	**13**	**450**	**1,626**	**1,267**	**18,101**	**5,972**	**750**
30													
31	**Other Revenue**												
32	Energy		-	-	-	-	-	-	-	-	-	-	-
33	Demand		(82,050)	(49,570)	(14,774)	(6)	(6)	(286)	(952)	(608)	(11,268)	(4,442)	(140)
34	Customer		(6,778)	(4,533)	(1,496)	(3)	(1)	(11)	(43)	(38)	(457)	(146)	(50)
35	**Total**	**Line 32 + 33 + 34**	**(88,828)**	**(54,102)**	**(16,270)**	**(8)**	**(7)**	**(297)**	**(994)**	**(646)**	**(11,725)**	**(4,587)**	**(190)**
36													
37	**Income Tax**												
38	Energy		820	441	152	1	0	-	-	-	133	59	33
39	Demand		28,758	15,490	5,709	0	1	126	346	211	4,879	1,983	11
40	Customer		21,909	18,203	2,534	4	2	15	68	64	764	192	62
41	**Total**	**Line 38 + 39 + 40**	**51,486**	**34,135**	**8,396**	**5**	**4**	**141**	**414**	**275**	**5,776**	**2,234**	**106**
42													
43	**Earned Return**												
44	Energy		6,122	3,297	1,134	7	1	-	-	-	995	443	246
45	Demand		214,767	115,684	42,640	3	11	940	2,583	1,575	36,436	14,812	83
46	Customer		163,620	135,947	18,928	26	18	112	511	478	5,704	1,432	463
47	**Total**	**Line 44 + 45 + 46**	**384,509**	**254,928**	**62,701**	**37**	**29**	**1,052**	**3,095**	**2,054**	**43,135**	**16,687**	**792**
48													
49	**TOTAL COST OF SERVICE MARGIN**												
50	Energy		52,592	32,047	7,828	26	3	172	621	606	7,672	2,343	1,274
51	Demand		521,250	275,025	105,029	3	27	2,359	6,374	3,852	91,251	37,262	68
52	Customer		480,595	386,419	63,531	99	62	423	1,480	1,428	20,035	5,353	1,766
53	**Total Cost of Service Margin**	**Sum of Total (Line 1 to 47); Sch. 2, Line 8**	**1,054,438**	**693,491**	**176,387**	**127**	**92**	**2,955**	**8,474**	**5,886**	**118,959**	**44,958**	**3,108**

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023 **Schedule 4**
COST OF SERVICE CLASSIFICATION ($000s)

Line	Particular	Cross Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
54													
55	Cost of Gas[1]												
56	Energy		1,134,316	614,049	217,315	1,133	127	80	289	282	186,045	73,891	41,105
57	Demand		-	-	-	-	-	-	-	-	-	-	-
58	Customer		-	-	-	-	-	-	-	-	-	-	-
59	**Total**	**Sch 1, Line 8 (Excl. Imputed Amount)**	**1,134,316**	**614,049**	**217,315**	**1,133**	**127**	**80**	**289**	**282**	**186,045**	**73,891**	**41,105**
60													
61	**TOTAL UTILITY REVENUE REQUIREMENT**												
62	Energy		1,186,908	646,096	225,143	1,159	130	253	910	888	193,717	76,234	42,379
63	Demand		521,250	275,025	105,029	3	27	2,359	6,374	3,852	91,251	37,262	68
64	Customer		480,595	386,419	63,531	99	62	423	1,480	1,428	20,035	5,353	1,766
65	**Total Utility Revenue Requirement**	**Line 53 + Line 59; Sch. 2, Line 11**	**2,188,754**	**1,307,540**	**393,702**	**1,260**	**219**	**3,035**	**8,763**	**6,168**	**305,004**	**118,849**	**44,213**
66													
67													

68 **Note:**
69 1. Exclude the imputed Cost of Gas for Rates 23, 25 and 27 which totaled to $113,214. See Note 1 of Schedule 1

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023
FUNCTIONALIZED RATE BASE CLASSIFICATION ($000s)

Schedule 5

Line	Particular	Cross Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations												
2	Energy		108,468	58,413	20,087	120	15	-	-	-	17,634	7,846	4,351
3	Demand		-	-	-	-	-	-	-	-	-	-	-
4	Customer		-	-	-	-	-	-	-	-	-	-	-
5	**Total**	**Line 2 + 3 + 4**	**108,468**	**58,413**	**20,087**	**120**	**15**	**-**	**-**	**-**	**17,634**	**7,846**	**4,351**
6													
7	LNG Storage Tilbury Base												
8	Energy		-	-	-	-	-	-	-	-	-	-	-
9	Demand		48,243	26,669	9,670	-	2	214	-	-	8,297	3,390	-
10	Customer		-	-	-	-	-	-	-	-	-	-	-
11	**Total**	**Line 8 + 9 + 10**	**48,243**	**26,669**	**9,670**	**-**	**2**	**214**	**-**	**-**	**8,297**	**3,390**	**-**
12													
13	LNG Storage Mt. Hayes												
14	Energy		-	-	-	-	-	-	-	-	-	-	-
15	Demand		148,876	79,896	28,970	-	6	642	2,716	1,634	24,856	10,155	-
16	Customer		-	-	-	-	-	-	-	-	-	-	-
17	**Total**	**Line 14 + 15 + 16**	**148,876**	**79,896**	**28,970**	**-**	**6**	**642**	**2,716**	**1,634**	**24,856**	**10,155**	**-**
18													
19	LNG Tilbury 1A												
20	Energy		-	-	-	-	-	-	-	-	-	-	-
21	Demand		447,772	294,494	74,904	54	39	1,255	3,599	2,499	50,516	19,092	1,320
22	Customer		-	-	-	-	-	-	-	-	-	-	-
23	**Total**	**Line 20 + 21 + 22**	**447,772**	**294,494**	**74,904**	**54**	**39**	**1,255**	**3,599**	**2,499**	**50,516**	**19,092**	**1,320**
24													
25	Transmission												
26	Energy		-	-	-	-	-	-	-	-	-	-	-
27	Demand		1,895,379	1,017,177	368,823	-	80	8,174	34,575	20,803	316,454	129,292	-
28	Customer		-	-	-	-	-	-	-	-	-	-	-
29	**Total**	**Line 26 + 27 + 28**	**1,895,379**	**1,017,177**	**368,823**	**-**	**80**	**8,174**	**34,575**	**20,803**	**316,454**	**129,292**	**-**
30													
31	Distribution												
32	Energy		-	-	-	-	-	-	-	-	-	-	-
33	Demand		897,699	433,607	200,206	0	45	4,761	465	283	183,139	75,181	12
34	Customer		2,357,617	1,952,356	280,215	316	282	1,390	7,899	7,499	84,603	17,669	5,388
35	**Total**	**Line 32 + 33 + 34**	**3,255,316**	**2,385,963**	**480,422**	**316**	**327**	**6,151**	**8,365**	**7,782**	**267,741**	**92,850**	**5,400**
36													
37	Marketing												
38	Energy		305,837	192,080	42,584	99	12	1,267	4,564	4,452	43,269	11,385	6,126
39	Demand		7	-	-	-	7	-	-	-	-	-	-
40	Customer		(12,922)	(11,059)	(1,125)	(5)	(0)	(20)	(14)	(8)	(331)	(259)	(100)
41	**Total**	**Line 38 + 39 + 40**	**292,922**	**181,022**	**41,458**	**94**	**19**	**1,246**	**4,550**	**4,444**	**42,938**	**11,125**	**6,025**
42													
43	Customer Accounting												
44	Energy		(31,803)	(18,595)	(6,551)	-	-	-	-	-	(6,657)	-	-
45	Demand		-	-	-	-	-	-	-	-	-	-	-
46	Customer		1,263	1,081	110	1	0	2	1	1	32	25	10
47	**Total**	**Line 44 + 45 + 46**	**(30,540)**	**(17,514)**	**(6,441)**	**1**	**0**	**2**	**1**	**1**	**(6,624)**	**25**	**10**
48													
49	TOTAL UTILITY RATE BASE												
50	Energy		382,502	231,899	56,119	219	28	1,267	4,564	4,452	54,246	19,231	10,477
51	Demand		3,437,977	1,851,844	682,574	55	180	15,046	41,355	25,219	583,263	237,110	1,332
52	Customer		2,345,958	1,942,378	279,200	311	282	1,372	7,887	7,492	84,304	17,435	5,298
53	**Total Utility Rate Base**	**Sum of Total (Line 1 to 47); Sch. 3, Line 15**	**6,166,437**	**4,026,121**	**1,017,893**	**585**	**490**	**17,684**	**53,805**	**37,163**	**721,813**	**273,776**	**17,107**
54													

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023
FUNCTIONALIZED COST OF SERVICE CLASSIFICATION ($000s)

Schedule 6

Line	Particular	Cross Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
1	**Gas Supply Operations**												
2	Energy		10,984	5,915	2,034	12	2	-	-	-	1,786	795	441
3	Demand		-	-	-	-	-	-	-	-	-	-	-
4	Customer		-	-	-	-	-	-	-	-	-	-	-
5	**Total**	**Line 2 + 3 + 4**	**10,984**	**5,915**	**2,034**	**12**	**2**	**-**	**-**	**-**	**1,786**	**795**	**441**
6													
7	**LNG Storage Tilbury Base**												
8	Energy		-	-	-	-	-	-	-	-	-	-	-
9	Demand		17,878	9,883	3,584	-	1	79	-	-	3,075	1,256	-
10	Customer		-	-	-	-	-	-	-	-	-	-	-
11	**Total**	**Line 8 + 9 + 10**	**17,878**	**9,883**	**3,584**	**-**	**1**	**79**	**-**	**-**	**3,075**	**1,256**	**-**
12													
13	**LNG Storage Mt. Hayes**												
14	Energy		-	-	-	-	-	-	-	-	-	-	-
15	Demand		6,963	3,737	1,355	-	0	30	127	76	1,163	475	-
16	Customer		-	-	-	-	-	-	-	-	-	-	-
17	**Total**	**Line 14 + 15 + 16**	**6,963**	**3,737**	**1,355**	**-**	**0**	**30**	**127**	**76**	**1,163**	**475**	**-**
18													
19	**LNG Tilbury 1A**												
20	Energy		-	-	-	-	-	-	-	-	-	-	-
21	Demand		33,869	22,275	5,666	4	3	95	272	189	3,821	1,444	100
22	Customer		-	-	-	-	-	-	-	-	-	-	-
23	**Total**	**Line 20 + 21 + 22**	**33,869**	**22,275**	**5,666**	**4**	**3**	**95**	**272**	**189**	**3,821**	**1,444**	**100**
24													
25	**Transmission**												
26	Energy		-	-	-	-	-	-	-	-	-	-	-
27	Demand		266,575	140,780	52,388	(2)	10	1,178	5,055	3,027	45,528	18,666	(56)
28	Customer		-	-	-	-	-	-	-	-	-	-	-
29	**Total**	**Line 26 + 27 + 28**	**266,575**	**140,780**	**52,388**	**(2)**	**10**	**1,178**	**5,055**	**3,027**	**45,528**	**18,666**	**(56)**
30													
31	**Distribution**												
32	Energy		-	-	-	-	-	-	-	-	-	-	-
33	Demand		195,962	98,351	42,037	1	10	977	919	559	37,665	15,420	24
34	Customer		403,444	320,393	56,812	68	61	302	1,396	1,381	18,059	3,804	1,168
35	**Total**	**Line 32 + 33 + 34**	**599,406**	**418,744**	**98,849**	**69**	**71**	**1,279**	**2,315**	**1,940**	**55,724**	**19,225**	**1,191**
36													
37	**Marketing**												
38	Energy		41,608	26,132	5,793	13	2	172	621	606	5,887	1,549	833
39	Demand		3	-	-	-	3	-	-	-	-	-	-
40	Customer		38,344	32,815	3,339	15	0	60	42	23	982	770	298
41	**Total**	**Line 38 + 39 + 40**	**79,955**	**58,946**	**9,133**	**29**	**5**	**232**	**663**	**629**	**6,869**	**2,318**	**1,131**
42													
43	**Customer Accounting**												
44	Energy		-	-	-	-	-	-	-	-	-	-	-
45	Demand		-	-	-	-	-	-	-	-	-	-	-
46	Customer		38,808	33,211	3,380	16	0	61	42	23	994	779	301
47	**Total**	**Line 44 + 45 + 46**	**38,808**	**33,211**	**3,380**	**16**	**0**	**61**	**42**	**23**	**994**	**779**	**301**
48													
49	**TOTAL COST OF SERVICE MARGIN**												
50	Energy		52,592	32,047	7,828	26	3	172	621	606	7,672	2,343	1,274
51	Demand		521,250	275,025	105,029	3	27	2,359	6,374	3,852	91,251	37,262	68
52	Customer		480,595	386,419	63,531	99	62	423	1,480	1,428	20,035	5,353	1,766
53	**Total Cost of Service Margin**	**Sum of Total (Line 1 to 47); Sch. 2, Line 8**	**1,054,438**	**693,491**	**176,387**	**127**	**92**	**2,955**	**8,474**	**5,886**	**118,959**	**44,958**	**3,108**
54													

FortisBC Energy Inc.
Fully Distributed Cost of Service Allocation Study
Test Year 2023

Schedule 7

CLASSIFICATION SUMMARY ($000s)

Line	Particular	Cross Reference	TOTAL	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 22A	RATE 22B	RATE 3/23	RATE 5/25	RATE 7/27
1	**Billing Determinants**												
2	Sales Volume (TJ)		188,656	82,890	29,204	166	21	2,128	7,669	7,481	29,674	19,130	10,293
3	Midstream Sales Volume (TJ)		154,882	82,890	29,204	166	21	-	-	-	25,770	10,827	6,004
4	Commodity Sales Volume (TJ)		149,668	80,601	27,717	166	21	-	-	-	24,333	10,827	6,004
5	Average No. of Customers		1,076,960	977,501	90,632	18	13	13	9	5	7,750	904	115
6													
7	**Cost of Service Margin**												
8	Energy	Schedule 6, Line 50	52,592	32,047	7,828	26	3	172	621	606	7,672	2,343	1,274
9	Unit Energy Charge ($/GJ)	Line 8 / Line 2	$ 0.279	$ 0.387	$ 0.268	$ 0.154	$ 0.154	$ 0.081	$ 0.081	$ 0.081	$ 0.259	$ 0.122	$ 0.124
10	Demand	Schedule 6, Line 51	521,250	275,025	105,029	3	27	2,359	6,374	3,852	91,251	37,262	68
11	Unit Demand Charge ($/GJ)	Line 10 / Line 2	$ 2.763	$ 3.318	$ 3.596	$ 0.017	$ 1.301	$ 1.109	$ 0.831	$ 0.515	$ 3.075	$ 1.948	$ 0.007
12	Customer	Schedule 6, Line 52	480,595	386,419	63,531	99	62	423	1,480	1,428	20,035	5,353	1,766
13	Unit Customer Charge ($/Customer/Day)	Line 12 x 1,000 / Line 5 / 365.25 days	$ 1.222	$ 1.082	$ 1.919	$ 15.049	$ 13.007	$ 89.072	$ 450.146	$ 781.898	$ 7.078	$ 16.211	$ 42.056
14													
15	**Total Cost of Service Margin**	**Sum of Line 8, 10, and 12; Sch. 6, Line 53**	**1,054,438**	**693,491**	**176,387**	**127**	**92**	**2,955**	**8,474**	**5,886**	**118,959**	**44,958**	**3,108**
16	Unit Cost of Service Margin ($/GJ)	Line 15 / Line 2	$ 5.589	$ 8.366	$ 6.040	$ 0.767	$ 4.411	$ 1.388	$ 1.105	$ 0.787	$ 4.009	$ 2.350	$ 0.302
17													
18	**Cost of Gas - Commodity & Midstream[1]**												
19	Energy	Sch. 4, Line 56 + Impute Amt RS 23/25/27)	1,247,531	614,049	217,315	1,133	127	80	289	282	214,059	130,006	70,191
20	Demand	Schedule 4, Line 57	-	-	-	-	-	-	-	-	-	-	-
21	Customer	Schedule 4, Line 58	-	-	-	-	-	-	-	-	-	-	-
22	**Total Cost of Gas - Commodity**	**Sum of Line 19 to 21**	**1,247,531**	**614,049**	**217,315**	**1,133**	**127**	**80**	**289**	**282**	**214,059**	**130,006**	**70,191**
23	Unit Cost of Gas - Commodity ($/GJ)	Line 22 / Line 2	$ 6.613	$ 7.408	$ 7.441	$ 6.821	$ 6.077	$ 0.038	$ 0.038	$ 0.038	$ 7.214	$ 6.796	$ 6.819
24													
25	**Total Utility Cost of Service**												
26	Energy	Line 8 + Line 19	1,300,123	646,096	225,143	1,159	130	253	910	888	221,731	132,349	71,465
27	Demand	Line 10 + Line 20	521,250	275,025	105,029	3	27	2,359	6,374	3,852	91,251	37,262	68
28	Customer	Line 12 + Line 21	480,595	386,419	63,531	99	62	423	1,480	1,428	20,035	5,353	1,766
29	**Total Utility Cost of Service**	**Sum of Line 26 to 28**	**2,301,968**	**1,307,540**	**393,702**	**1,260**	**219**	**3,035**	**8,763**	**6,168**	**333,017**	**174,964**	**73,299**
30	Unit Cost of Gas - Commodity ($/GJ)	Line 29 / Line 2	$ 12.202	$ 15.774	$ 13.481	$ 7.588	$ 10.487	$ 1.426	$ 1.143	$ 0.824	$ 11.223	$ 9.146	$ 7.121
31													
32	**Revenue @ Proposed Rates**												
33	**Total Delivery Margin @ Proposed Rates**	**Schedule 1, Line 26**	**1,054,438**	**663,269**	**168,726**	**385**	**84**	**3,106**	**8,634**	**5,894**	**132,088**	**53,706**	**18,544**
34	Unit Delivery Rate ($/GJ)	Line 33 / Line 2	$ 5.589	$ 8.002	$ 5.777	$ 2.320	$ 4.014	$ 1.460	$ 1.126	$ 0.788	$ 4.451	$ 2.807	$ 1.802
35													
36	**Total Revenue @ Proposed Rates**	**Schedule 1, Line 28**	**2,301,968**	**1,277,318**	**386,041**	**1,518**	**211**	**3,187**	**8,923**	**6,176**	**346,147**	**183,712**	**88,734**
37	Unit Rate ($/GJ)	Line 36 / Line 2	$ 12.202	$ 15.410	$ 13.219	$ 9.141	$ 10.090	$ 1.497	$ 1.164	$ 0.826	$ 11.665	$ 9.603	$ 8.621
38													
39	Margin to Cost Ratio @ Proposed Rates	Line 33 / Line 15	100.0%	95.6%	95.7%	302.5%	91.0%	105.1%	101.9%	100.1%	111.0%	119.5%	596.6%
40	**Revenue to Cost Ratio @ Proposed Rates**	**Line 36 / Line 29**	**100.0%**	**97.7%**	**98.1%**	**120.5%**	**96.2%**	**105.0%**	**101.8%**	**100.1%**	**103.9%**	**105.0%**	**121.1%**
41													
42													
43	**Note:**												
44	1. Includes the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Rates 23, 25 and 27 are T-Service thus do not have commodity and midstream charges.												

Appendix E

MINIMUM SYSTEM STUDY RESULTS AND PEAK LOAD CARRYING CAPACITY STUDY RESULTS

MINIMUM SYSTEM AND PEAK LOAD CARRYING CAPACITY STUDIES

The following appendix discusses the purpose and results of the Minimum System Study (MSS) and Peak Load Carrying Capacity (PLCC) Study. Each study was developed to support the Cost of Service Allocation study and the results produced by the two studies aid in the classification of costs associated with distribution mains.

1.1 *PURPOSE OF MINIMUM SYSTEM STUDY*

Distribution mains costs have been classified as demand or customer related based on the results of the MSS.

As described in Section 4.3.2.4.1 of the Application, the MSS assumes that a certain level of plant investment is required to serve the minimum loading requirements of customers throughout the service territory. To estimate the value of mains required from a customer connection vs. the demand component FEI follows the steps outlined below:

1. Obtain the length of mains by diameter and material included in all of FEI's service areas,
2. Estimate the replacement cost of mains by diameter and material using zone based geo-pricing and inflating prices to 2022 dollars using PBR approved inflation rates,
3. Value FEI's mains at their estimated replacement cost,
4. Value FEI's mains at the minimum standard size and material (60mm PE),
5. Calculate the customer-related component of FEI's mains by dividing number 4 above by number 3 above,
6. Calculate the demand-related component as one minus number 5 above

The percentages calculated in steps 5 and 6 above are applied to FEI's distribution mains embedded costs to split those costs into customer and demand related components. However, in the MSS, the proportion of costs determined to be customer related is overstated since the 60 mm pipe (customer related portion) also has the ability to carry some demand. As a result, an adjustment to account for the PLCC of the minimum system is required and together the two studies better represent the demand and customer related components of the distribution system.

1.2 *MINIMUM SYSTEM STUDY RESULTS*

To determine the demand versus customer related proportion, the steel and plastic weighted costs are summed for each pipe diameter and then the summed weighted costs for the minimum distribution system are compared to the total weighted costs for the entire distribution system.

The following tables present the MSS results for the entire distribution system. The first table summarizes the combined minimum weighted cost per diameter results for all mains, as well as the customer and demand related component percentages. The subsequent tables show the results per material type (steel and plastic/polyethylene). In all three tables the mains have been separated by pipe diameter and each diameter has been allocated length of pipe installed and unit costs per length to determine the actual total weighted cost per pipe diameter.

Table 1: MSSResults for All Mains

COMBINED STEEL & PLASTIC MAINS

Line No.	Diameter Inches	Diameter mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
	(1)	(2)	(3)	(4)	(5)	(6)
1	0.6	15	209,901	$ 72.98	$ 15,319,056	$ 15,319,056
2	0.8	21	43,244	270.27	11,687,393	11,687,393
3	1.0	26	1,618,609	200.10	323,882,052	323,882,052
4	1.3	33	17,699	269.78	4,774,910	4,774,910
5	1.7	42	8,199,552	123.45	1,012,269,020	1,012,269,020
6	1.9	48	41,968	267.16	11,212,028	11,212,028
7	2.4	60	10,305,378	161.16	1,660,767,325	1,660,767,325
8	0.6	15	-	-	-	-
9	0.8	21	196	271.44	53,202	53,202
10	1.0	26	1,973	271.44	535,547	535,547
11	1.3	33	22	271.44	5,972	5,972
12	1.7	42	7,863	271.44	2,134,315	2,134,315
13	1.9	48	-	-	-	-
14	2.4	60	36,054	271.35	9,783,173	9,783,173
15	2.9	73	86	411.04	35,350	22,536
16	3.5	88	1,620,248	227.69	368,915,072	235,191,481
17	4.0	101	592	424.70	251,423	160,287
18	4.5	114	2,879,521	290.62	836,849,266	533,509,833
19	6.6	168	1,259,862	581.64	732,791,714	235,141,799
20	8.6	219	313,600	4,241.36	1,330,091,394	71,117,519
21	10.7	273	48,922	5,581.92	273,078,687	13,278,672
22	12.7	323	130,645	6,191.05	808,830,177	35,461,581
23	14.0	355	-	-	-	-
24	16.0	406	33,443	6,927.20	231,666,413	9,077,693
25	18.0	457	1,927	9,238.00	17,801,626	523,061
26	20.0	508	57,521	7,859.89	452,108,642	15,613,371
27	24.0	609	1,497	10,233.00	15,318,801	406,342
28	30.0	762	31,564	9,330.27	294,500,584	8,567,661
29	36.0	914	3	12,623.00	37,869	814
30	42.0	1067	-	-	-	-
31	**Total**		**26,861,890**		**$ 8,414,701,010**	**$ 4,210,496,645**
32						
33	**Customer Related Component**			Line 31, Column (6) / Line 31, Column (5)		**50%**
34	**Demand Related Component**			1 - Line 33, Column (6)		**50%**

Table 2: Steel Mains Weighted Cost per Diameter

STEEL MAINS

Line No.	Diameter – Inches	Diameter – mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
	(1)	(2)	(3)	(4)	(5)	(6)
1	0.6	15	3,518	$ 271.44	$ 954,918	$ 954,918
2	0.8	21	42,993	271.44	11,669,923	11,669,923
3	1.0	26	1,046,783	271.41	284,105,334	284,105,334
4	1.3	33	17,554	271.44	4,764,818	4,764,818
5	1.7	42	2,190,500	271.38	594,453,526	594,453,526
6	1.9	48	41,891	267.52	11,206,669	11,206,669
7	2.4	60	4,696,343	270.71	1,271,344,086	1,271,344,086
8	0.6	15	-	-	-	-
9	0.8	21	196	271.44	53,202	53,202
10	1.0	26	1,973	271.44	535,547	535,547
11	1.3	33	22	271.44	5,972	5,972
12	1.7	42	7,863	271.44	2,134,315	2,134,315
13	1.9	48	-	-	-	-
14	2.4	60	36,054	271.35	9,783,173	9,783,173
15	2.9	73	82	425.77	34,913	22,258
16	3.5	88	608,239	425.09	258,553,692	164,833,671
17	4.0	101	590	425.77	251,204	160,148
18	4.5	114	1,653,797	425.25	703,273,444	448,352,305
19	6.6	168	729,753	845.87	617,278,536	198,075,364
20	8.6	219	243,577	5,377.00	1,309,713,529	66,115,993
21	10.7	273	48,883	5,580.00	272,767,140	13,268,692
22	12.7	323	130,637	6,191.00	808,773,667	35,459,814
23	14.0	355	-	-	-	-
24	16.0	406	33,400	6,923.00	231,228,200	9,066,021
25	18.0	457	1,927	9,238.00	17,801,626	523,061
26	20.0	508	57,287	7,846.00	449,473,802	15,549,855
27	24.0	609	1,497	10,233.00	15,318,801	406,342
28	30.0	762	11,737	9,775.00	114,729,175	3,185,865
29	36.0	914	-	-	-	-
30	42.0	1067	-	-	-	-
31		**Total**	**11,607,096**		**$ 6,990,209,211**	**$ 3,146,030,871**
32	Coquitlam - Vancouver IP (LMIPSU)					
33	4.5	114	12	425.77	$ 5,109	$ 3,257
34	6.6	168	864	845.90	730,861	$ 234,522
35	8.6	219	634	8,403.00	5,327,502	$ 172,092
36	10.7	273	36	8,636.00	310,896	$ 9,772
37	12.7	323	6	9,346.00	56,076	$ 1,629
38	16.0	406	43	10,191.00	438,213	$ 11,672
39	20.0	508	234	11,260.00	2,634,840	$ 63,516
40	30.0	762	19,827	9,067.00	179,771,409	$ 5,381,796
41	36.0	914	3	12,623.00	37,869	$ 814
42		**Total**	**21,659**		**$ 189,312,775**	**$ 5,879,070**

Table 3: Plastic Mains Weighted Cost per Diameter

PLASTIC MAINS

Line No.	Diameter Inches	Diameter mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
1	0.6	15	206,383	$ 69.60	$ 14,364,138	$ 14,364,138
2	0.8	21	251	69.60	17,469	17,469
3	1.0	26	571,826	69.56	39,776,719	39,776,719
4	1.3	33	145	69.60	10,092	10,092
5	1.7	42	6,009,052	69.53	417,815,494	417,815,494
6	1.9	48	77	69.60	5,359	5,359
7	2.4	60	5,609,035	69.43	389,423,239	389,423,239
8	0.6	15		-	-	-
9	0.8	21		-	-	-
10	1.0	26		-	-	-
11	1.3	33		-	-	-
12	1.7	42		-	-	-
13	1.9	48		-	-	-
14	2.4	60		-	-	-
15	2.9	73	4	109.17	437	278
16	3.5	88	1,012,009	109.05	110,361,380	70,357,810
17	4.0	101	2	109.17	218	139
18	4.5	114	1,225,712	108.97	133,570,713	85,154,271
19	6.6	168	529,245	216.88	114,782,317	36,831,913
20	8.6	219	69,389	216.90	15,050,363	4,829,434
21	10.7	273	3	216.90	651	209
22	12.7	323	2	216.90	434	139
23	14.0	355		-	-	-
24	16.0	406	-	-	-	-
25	18.0	457	-	-	-	-
26	20.0	508	-	-	-	-
27	24.0	609	-	-	-	-
28	30.0	762	-	-	-	-
29	36.0	914	-	-	-	-
30	42.0	1067	-	-	-	-
31		**Total**	**15,233,135**		**$ 1,235,179,024**	**$ 1,058,586,704**

1.3 *PURPOSE OF PEAK LOAD CARRYING CAPACITY STUDY*

In the MSS the proportion of costs determined to be customer related is overstated since the customer related portion also has the ability to carry some demand. As a result an adjustment to account for the PLCC of the minimum system is required.

The PLCC adjustment involves the FEI System Capacity Planning Department determining the theoretical capacity of each distribution system in the Province assuming a 60 mm (2 inch) main diameter. The 60 mm main diameter is the minimum size normally installed by the Company as specified by the FEI installation standard. The capacities of the minimum sized distribution systems are then divided by the number of customers served by each distribution system and an average minimum system capacity per customer (the PLCC Adjustment) is calculated. This PLCC Adjustment is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the peak demand for that rate class to get the PLCC adjusted peak demand. This PLCC adjusted peak demand is then used to allocate the demand related costs for the Distribution function.

The Minimum System approach with PLCC Adjustment more closely matches the theoretical demand and customer related components of the distribution system, and is important to consider with the increase in the Company's minimum installation size of mains to 60 mm.

1.4 *PLCC ADJUSTMENT*

Table 4 presents the total PLCC Adjustment for the FEI (*0.206 GJ/day/customer*) and details associated with the PLCC calculation, which was calculated through the following steps:

1. The System Planning Department calculates the load capacity of each distribution network in the Province for the Amalgamated Entity assuming only 60 mm mains are used.
2. Since each network serves a different number of customers, the average system capacity is calculated by summing the network capacities and dividing by the total number of customers.

1 **Table 4: PLCC Summary – Capacity Calculation of Each Distribution System with 60 mm Mains**

Network Area Model	Design Degree Day	Heating Value (MJ/m³)	Load for PLCC (m³/h)	Customers	Total consumption GJ/d
100 Mile-Clinton	53.6	39.132	3,458	5,434	3,248
700 kPa - Annacis	30.2	38.818	1,040	717	969
Cache Creek-Ashcroft	46.7	38.859	2,090	1,416	1,949
Campbell River and Comox-Courtenay-Cumberland	31.9 - 27.8	38.818	7,210	23,033	6,717
Castlegar	39.7	38.190	3,574	5,119	3,276
Central Kootenay	39.7	38.190	3,061	8,394	2,806
Chemainus-Crofton	29.9	38.819	1,364	1,853	1,271
Chetwynd	57.2	39.132	1,143	1,587	1,073
Chilliwack	36.3	38.819	4,472	33,877	4,166
Coquitlam	30.2	38.818	11,293	57,882	10,521
Cranbrook-Kimberley	48.4	38.057	4,145	14,425	3,786
CRD-Victoria	28.8	38.819	12,120	57,928	11,292
Creston	39.7	38.190	1,145	3,469	1,049
Del-Abb	30.2 - 32.5	38.818	40,846	246,930	38,053
Duncan-Shawnigan Lake	29.9	38.818	1,042	7,442	971
East Kootenay	48.4	38.057	2,190	7,386	2,000
Fort Nelson	60.4	37.764	3,310	2,553	3,000
Gibson-Roberts Creek-Sechelt	29.0	38.818	1,908	8,033	1,778
Greater Kamloops	46.7	38.859	14,954	37,843	13,946
Greater Kelowna	43.9	38.343	13,857	68,338	12,752
Greater Salmon Arm	43.9	38.343	6,085	14,244	5,600
Hope	36.3	38.819	768	2,899	716
Hudson Hope	57.2	39.132	916	436	860
Kent	36.3	38.819	889	2,664	828
Ladysmith	29.9	38.819	1,002	2,331	934
Mackenzie	56.9	39.132	932	1,827	875
Maple Ridge	30.2	38.819	6,260	32,101	5,832
Merritt-Logan Lake	46.7	38.859	3,640	4,968	3,395
Mission	32.5	38.818	2,862	11,904	2,666
N. Van.-W. Van.	30.2	38.818	7,086	46,647	6,602
Nanaimo-Harmac	29.9	38.819	4,675	21,362	4,355
Nelson	39.7	38.190	460	5,892	421
North Okanagan	43.9	38.343	4,290	28,989	3,948
Parksville-Qualicum	29.9	38.818	1,885	10,672	1,756
Port Alberni	29.9	38.819	1,414	4,351	1,317
Powell River	29.0	38.819	1,903	4,478	1,773
Prince George-Hixon	56.0	39.132	7,533	32,751	7,074
Princeton	43.9	38.343	919	1,677	846
Quesnel	55.0	39.132	1,632	8,501	1,533
Revelstoke	43.6	93.026	212	2,115	472
Richmond	30.2	38.818	7,448	51,265	6,939
South Okanagan	39.1	38.321	6,978	27,083	6,417
Squamish-Brackendale	32.9	38.818	1,517	5,738	1,414
Vancouver-Burnaby-New West	30.2	38.818	27,808	158,919	25,907
West Kootenay	39.7	38.190	4,719	4,049	4,325
Whistler	39.5	38.819	985	3,522	918
Williams Lake	53.6	39.132	2,997	7,863	2,815
				1,092,907	**225,161**

2 **Average consumption per Customer (Average GJ/d Customer)** **0.206**

1.5 *SUMMARY*

The MSS with PLCC Adjustment classifies costs associated with distribution mains into customer and demand related components. Along with the use of the PLCC Adjustment, the two studies produce results that closely match the theoretical demand and customer related components of the distribution system.