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

Stargas Utilities Ltd.

Delivery Rate and Regulatory Account Application Effective November 1, 2020 (2021 Revenue Requirements Application)

Decision and Order G-158-21

May 25, 2021

Before:
C. M. Brewer, Panel Chair
K. A. Keilty, Commissioner
B. A. Magnan, Commissioner

TABLE OF CONTENTS

Page no.

Executive summary

Stargas Utilities Ltd. (Stargas) requests that the British Columbia Utilities Commission (BCUC) approve a permanent delivery rate decrease from $5.77 per gigajoule (GJ) to $4.59 per GJ, effective November 1, 2020, based on its forecast cost of service or revenue requirement (Revenue Requirement) of $221,235 and load forecast of 48,250 GJ of natural gas for the period November 1, 2020 to October 31, 2021 (2021). Stargas also seeks BCUC approval related to several new and existing regulatory or deferral accounts.

Based on the key findings discussed below, the Panel approves a delivery rate of $4.21 per GJ for all ratepayers on a permanent basis, effective November 1, 2020. The table below sets out Stargas' 2021 forecast Revenue Requirement, load forecast and resulting delivery rate compared to the calculated revenue surplus based on applying the existing approved delivery rate of $5.77 per GJ.

Final Revenue Requirement, Revenue Surplus and Approved Delivery Rate

	Revenue Requirement	Revenue (Surplus)
2021 Proposed	**$221,235**	**$(57,168)**
Disallowed incremental CMI administration and office lease costs	(21,483)	(21,483)
Recognition of Forecast Regulatory Costs	17,500	17,500
Amortization of 2018 Incident Shortfall Regulatory Account	16,687	16,687
Amortization of the 2017 New Service Installations Regulatory Account	(31,000)	(31,000)
2021 Approved	**$202,939**	**$(75,464)**
2021 Approved Load Forecast	48,250 GJ	48,250 GJ
Reduction compared to 2017 Delivery Rate per GJ		$(1.56)
2021 Approved Delivery Rate per GJ	**$4.21**	

In setting a delivery rate of $4.21 per GJ, the Panel makes the following key findings and determinations:

- Stargas' proposed increase in CMI administration and office lease costs is not reasonable. **The Panel limits the increase in forecast CMI administration fees to an inflationary amount compared to the amount approved in the 2017 Revenue Requirement Application Decision (2017 RRA Decision).** The Panel also finds Stargas' proposal to include a new office lease expense in 2021 is not warranted since Stargas has not historically included a cost for office space and the amount proposed for 2021 does not represent costs expected to be incurred;
- Stargas' proposed 2021 CMI regulatory costs are not reasonable. The Panel limits the amount to $17,500, representing 50 percent of the proposed amount plus a reasonable increase over the 2017 approved CMI regulatory costs of $13,853. Given the reduction in the 2021 delivery rate, the Panel also denies Stargas' request to record approved 2021 regulatory costs in a regulatory account and to defer the recovery mechanism until a future application. **Stargas is directed to include the approved 2021 CMI regulatory costs in the 2021 Revenue Requirement and 2021 delivery rate**;
- Stargas' proposal to classify and recover the CMI administration cost of negotiating the current FEI technical and administrative services agreement as regulatory costs is not appropriate. Costs of this nature are normal administrative activities that are inherently included in the approved CMI administration fee. Therefore, **the Panel denies Stargas' proposal to classify and recover the $6,876 costs of negotiating the current FEI technical and administrative services agreement as CMI regulatory costs**;

- The proposed additions to the approved 2018 Incident Shortfall regulatory account are supported by sufficient evidence and reasonable explanations. **However, the Panel denies Stargas' request to defer the recovery of this account to a future period given the reduction in the 2021 delivery rate. Stargas is directed to include amortization of the account in the 2021 Revenue Requirement and 2021 delivery rate;**
- Stargas is not in compliance with the previous BCUC directive to establish a regulatory account to capture the incremental revenues and costs associated with new service installations. The New Services Installations Regulatory Account, which should have remained in effect until the filing of this Application, was approved given the expectation that a change in Stargas's extension policy was anticipated to result in an increase in the load that was not reflected in the 2017 load forecast or existing approved delivery rate. The Panel determines that a credit of $31,000 is an appropriate amount to be reflected in the regulatory account and sees no regulatory justification for deferring recognition of this ratepayer credit to a future period. **Stargas is directed to include this credit of $31,000 in the 2021 Revenue Requirement and 2021 delivery rate;** and
- Stargas' other 2021 forecast Revenue Requirement items and load forecast provide a reasonable basis for setting the 2021 delivery rate.

Regarding Stargas' request for regulatory accounts to recover proposed 'interest deficit' and 'undistributed return on equity' amounts for the period June 1, 2017 to October 31, 2020, the Panel finds these requests to be without merit and to constitute retroactive ratemaking. Since the 2017 RRA Decision set the delivery rate on a permanent basis and deferral accounts related to deemed interest and capital structure were not sought nor established, the BCUC cannot now retroactively change the rate paid by ratepayers. The BCUC could only do so if there was a deferral account or if the rates were set on an interim basis. **Accordingly, Stargas' request for regulatory accounts to recover proposed 'interest deficit' and 'undistributed return on equity' amounts for the period June 1, 2017 to October 31, 2020, is denied**.

Stargas' approved delivery rate for 2021 is a reduction of $1.56 per GJ from the interim approved rate. **Stargas is directed to refund to ratepayers the difference between the interim rates and permanent delivery rates, with interest at the average prime rate of Stargas' principal bank for the most recent year, at the same time the difference between interim and permanent commodity rates is recovered from ratepayers pursuant to Order G-133-21**.

1.0 Introduction

Stargas Utilities Ltd. (Stargas) requests that the British Columbia Utilities Commission (BCUC) approve a permanent delivery rate decrease from $5.77 per gigajoule (GJ) to $4.59 per GJ effective November 1, 2020, based on its forecast cost of service or revenue requirement (Revenue Requirement) and load forecast for the period November 1, 2020 to October 31, 2021 (2021).

Stargas forecasts a 2021 Revenue Requirement of $221,235 and load forecast of 48,250 GJ of natural gas to arrive at the proposed delivery rate of $4.59 per GJ.[1] Stargas also seeks BCUC approval related to several new and existing regulatory or deferral accounts.

The BCUC approved an interim delivery rate on October 28, 2020, directing Stargas to maintain its existing delivery rate on a refundable or recoverable basis until this proceeding has been completed.[2]

This Decision sets out the key issues to be decided by the Panel, provides an overview of relevant evidence, considers Stargas' proposals, and outlines the reasons for its decision for setting the permanent delivery rate effective November 1, 2020. The Panel addresses the following key issues:

- The reasonableness of the 2021 forecast Revenue Requirement and load forecast for the purpose of setting the 2021 delivery rate;
- The appropriateness of Stargas' requests related to several regulatory accounts; and
- The determination of a just and reasonable delivery rate for 2021.

1.1 Application and Approvals Sought

On September 22, 2020, Stargas filed a Delivery Rate and Regulatory Account Application which is its 2021 revenue requirements application (RRA) with the BCUC and the application was supplemented with additional information (Application).[3] Stargas outlines the following in the Application:

- A decrease in the forecast 2021 Revenue Requirement of $221,235 compared to 2017 approved amount of $237,125;
- An increase in the 2021 load forecast to 48,250 GJ of natural gas, representing a 3.2 percent increase over actual 2020 natural gas consumption of 46,767 GJ;
- A request for approval of a permanent decrease in the delivery rate of $1.18 per GJ, from $5.77 per GJ to $4.59 per GJ, effective November 1, 2020;[4]
- A request for approval of the creation of the new regulatory accounts, with the amortization period to be determined in a future proceeding as follows:[5]
    - A regulatory account to recover regulatory costs related to this Application;
    - A regulatory account to recover an interest deficit in the period June 1, 2017 to October 31, 2020;
    - A regulatory account to recover allowed but undistributed returns on equity in the period June 1, 2017 to October 31, 2020; and

[1] Exhibit B-6, BCUC IR 1.3.
[2] Order G-272-20 and the accompanying Reasons for Decision dated October 28, 2020, p. 1.
[3] Exhibit B-2, Supplemental Information.
[4] Stargas Final Argument, p. 1.
[5] Exhibit B-1-1, pp. 30–37; Exhibit B-2, Section 5. i. Regulatory Accounts, pp. 2–3.

- A request for final approval of the amount to be recovered in an existing 2018 Regulatory Account to Cover Incident Shortfall, with the amortization period to be determined in a future proceeding.[6]

1.2 Background

Stargas was formed in 1999 by Silver Star Mountain Resort Ltd. (Resort) to own and operate a natural gas distribution system at the Silver Star Mountain Ski Resort (Silver Star) pursuant to a Certificate of Public Convenience and Necessity (CPCN).[7] Silver Star is a year-round resort community located approximately 22 kilometers north-east of Vernon, B.C., for which the Resort is the primary developer of Silver Star and operates the ski hill and certain commercial operations within the resort boundaries.[8] At the time of this Application, Stargas serves 348 residential and commercial customers at Silver Star.[9]

CMI Holdings (1998) Inc. (CMI) is the sole shareholder of Stargas. CMI is a limited liability company controlled and owned by Mr. M. A. Blumes and his wife, Mrs. C. M. Iles-Blumes.[10]

Since 2009, FortisBC Alternate Energy Services Inc. (FAES), an affiliate of FEI, or FortisBC Energy Inc. (FEI) (since 2019)[11] have been contracted to provide technical and administrative services pertaining to the operation of the utility,[12] including emergency standby and response, system maintenance, leak survey and remedial action, meter servicing and replacement, conversion of meter reads to gigajoules (GJ), and the preparation and distribution of monthly invoices to Stargas ratepayers.[13] Mr. M. A. Blumes and Mr. Murray Iles provide supplemental administrative and management services to Stargas through CMI, or its subsidiary (Okanagan Funding Ltd.).[14]

In 2017, the BCUC approved Stargas' current delivery rate of $5.77 per GJ (2017 RRA Decision).[15] As part of the 2017 RRA Decision, the BCUC directed Stargas to file by July 31, 2019, an application for a new delivery rate that would take effect on November 1, 2019.[16]

In September 2019, Stargas filed its delivery rate application as directed in the 2017 RRA Decision, but subsequently withdrew the application and applied for an extension to file the application by no later than March 31, 2020. The BCUC approved the extension request,[17] as well as subsequent extension requests, ultimately requiring Stargas to file the application by no later than September 30, 2020.[18]

1.3 Legislative and Regulatory Framework

Stargas filed the Application pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA). The UCA sets out the framework for approval of rates which includes the following:

[6] Exhibit B-1-1, p. 26; Exhibit B-2, Section 5. i. Regulatory Accounts, pp. 1–2.
[7] Granted by the BCUC by Order C-4-00 dated March 30, 2000. Stargas was previously known as the Silver Star Mountain Resort Utilities Ltd. and the CPCN amended to reflect Stargas' new name by Order C-18-06 dated October 11, 2006.
[8] Order G-59-17 and the accompanying Reasons for Decision dated April 27, 2017 (2017 RRA Decision), p. 3.
[9] Exhibit B-1-1, p. 1.
[10] Order G-68-00 dated July 6, 2000, Order G-80-02 dated November 7, 2002, and Order G-139-11 dated August 4, 2011.
[11] Exhibit B-1-1, p. 4.
[12] Exhibit B-8, BCUC IR 2.1.
[13] 2017 RRA Decision, p. 3; Exhibit B-8, BCUC IR 2.2.1; Exhibit B-1-1, p. 4.
[14] Exhibit B-1-1, pp. 4, 7–8.
[15] Order G-59-17 and the accompanying Reasons for Decision dated April 27, 2017.
[16] 2017 RRA Decision, p. 25.
[17] Letter L-54-19 dated November 1, 2019.
[18] Letter L-17-20 dated March 27, 2020 and Letter L-55-20 dated August 31, 2020; Exhibit B-1-1, p. 1.

- Section 59(5) defines what an “unjust” or “unreasonable” rate is while section 59(4) states the determination of what is “unjust” or “unreasonable” is a question of fact of which the BCUC is the sole judge;
- Sections 58 and 60 authorize the BCUC to establish rates and includes mandatory considerations, including the requirement that rates not be “unjust, unreasonable, unduly discriminatory or unduly preferential;” and
- Section 60(1)(b.1) provides that in setting a rate, the BCUC may use “any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period.”

The Panel conducts its review of the Application based on the legislative authority outlined above, using a traditional Cost of Service (COS) approach. A COS approach is consistent with the rate setting method used in the 2017 RRA Decision proceeding. To apply this COS approach, the Panel must first determine Stargas’ total revenue requirement or its “cost of service.” A utility’s revenue requirement reflects the total amount of revenue that must be collected in rates to recover its costs and provide the utility with an opportunity to earn a reasonable return on its invested capital or its return on equity (ROE). This COS approach links rates to recovery of the operating and capital costs based on forecast revenues and costs. The COS elements of a forecast revenue requirement include the following basic components:

- Reasonable and necessary costs;
- Return of investment through recovery of depreciation expense; and
- Return on investment through an allowed rate of return on invested capital.

Under a COS approach, revenue and cost components that are outside a utility’s control may be handled through regulatory accounts and deferral mechanisms designed to capture and flow through forecast variances to future rates.

1.4 Regulatory Process

The BCUC established a written public hearing process and regulatory timetables for the review of the Application, which included two rounds of BCUC and intervener information requests (IRs) and written final and reply arguments.[19]

Silver Star Property Owners Association (SSPOA) is the sole intervener which registered and actively participated in the proceeding. The BCUC did not receive any letters of comment.

During the proceeding, Stargas informed the BCUC that FEI and Stargas had executed an Asset Purchase Agreement (FEI-Stargas APA) that, subject to BCUC approval, provides for the sale of Stargas’ regulatory assets and operations to FEI.[20] In light of that agreement, Stargas re-submitted exhibits previously filed in confidence in the proceeding, affirming that they can be made public.[21]

On January 12, 2021, SSPOA sought procedural guidance on the review of the Application given that FEI and Stargas had executed an asset purchase agreement. In response, the Panel stated that it is appropriate to proceed with the regulatory process to set 2021 delivery rates, considering the Application and related evidence on the evidentiary record. The Panel noted at that time that neither FEI nor Stargas had filed an application with

[19] Orders G-272-20, G-328-20 and G-22-21.
[20] Exhibit B-6, p. 1; Exhibit B-7, p. 1.
[21] Exhibit B-8.

the BCUC for approval of the FEI-Stargas APA and that the Panel will not be considering the implications of the proposed sale as part of the current proceeding since the approval of the APA remains undetermined.[22]

On February 19, 2021, FEI and Stargas filed a joint application to the BCUC seeking approval for

- Stargas to dispose of and transfer to FEI the natural gas distribution utility assets owned by Stargas within the boundaries of the Silver Star, and
- a CPCN for FEI to operate the resulting extension to its system (Asset Disposition Application).

The Asset Disposition Application is currently being reviewed in a separate BCUC proceeding.

2.0 2021 Revenue Requirement and Load Forecast

In this section, the Panel reviews Stargas' 2021 forecast Revenue Requirement and its 2021 load forecast in the context of setting the 2021 delivery rate. As noted above, the Panel must determine if the forecast Revenue Requirement appropriately reflects the total amount of revenue that must be collected in rates to recover the COS including the utility's ROE. Stargas' proposed delivery rate is calculated based on the total forecast Revenue Requirement for 2021 divided by the total load or delivery volume forecast for the 12 months ending October 31, 2021.

2.1 2021 Revenue Requirement

Table 1 below sets out Stargas' 2021 forecast Revenue Requirement and the calculated revenue surplus based on applying the existing approved delivery rate of $5.77 per GJ compared to the 2017 approved Revenue Requirement and 2019 and 2020 actual amounts. Due to a change in year end, Stargas' 2018 actual amounts were provided for a 12-month period ended May 31. The Panel excluded these results from the table below as they are not directly comparable to the November 1 to October 31 period of the 2017 Approved, 2019 and 2020 Actual, and 2021 Forecast revenue requirements.

[22] Exhibit A-7.

Table 1: Stargas 2021 Forecast Revenue Requirement and Revenue Surplus[23]

Component	2017 Approved	2019 Actual	2020 Actual	2021 Forecast
Technical Services	$ 60,766	$ 69,925	$ 69,482	$ 71,893
Administration				
Professional services	6,200	9,501	2,496	7,225
Insurance	13,130	11,703	8,822	9,000
Office and sundries	15,028	19,299	22,774	20,652
Office lease	-	-	-	6,240
Administration - FEI	59,735	69,173	55,544	54,000
Administration - CMI	46,757	43,754	47,477	66,743
Amortization	54,804	40,231	20,308	23,250
2002-2006 Deferred return	6,794	6,794	6,794	6,794
Basic charge recovery	(62,990)	(68,855)	(73,720)	(75,915)
Sundry revenue	(4,102)	(4,964)	(6,455)	(6,480)
Net meter and lines recovery	(170)	(149)	-	-
Income tax	9,300	5,379	11,600	3,119
Deemed interest	11,567	11,567	12,812	12,979
ROE	20,306	20,306	21,454	21,735
Additional earned return	-	37,638	70,455	-
Revenue Requirement	**$ 237,125**	**$ 271,302**	**$ 269,843**	**$ 221,235**
Revenue at Existing Delivery Rate of $5.77 per GJ	$ (237,125)	$ (271,302)	$ (269,843)	(278,403)
Revenue (Surplus)	**$ -**	**$ -**	**$ -**	**$ (57,168)**

Stargas' 2021 forecast Revenue Requirement is to decreases the total forecast Revenue Requirement by approximately $16,000, or 6.7 percent, compared to the 2017 approved Revenue Requirement. This decrease is primarily driven by the following factors:

- Lower amortization of $38,287 related to capital assets that are now fully amortized. In May 2019 Stargas completed the 20-year amortization of its contribution to FEI to subsidize a gas pipeline to Stargas' service site and the 10-year amortization of deferred property and equipment and deferred interest charges;[24]
- Lower administration fees paid to FEI due to changes to the service agreement for contracted services which now provides for a fixed monthly charge of $4,500 per month;[25] and
- Reduced income taxes at a 12 percent rate based on the utility's projected pre-tax income.[26]

The decrease is partially offset by the following factors:

- Amortization related to distribution grid and other capital asset additions since 2017, including meter reading and billing software and a safety initiative to map all of Stargas' meters;

[23] Exhibit B-6, BCUC IR 1.3, 2.5 All amounts in the table are for a November 1 to October 31 period.
[24] Exhibit B-2, p. 2
[25] Exhibit B-1-1, p. 4.
[26] Exhibit B-2, p. 2.

- Increases in technical services costs due to higher expected delivery volumes compared to 2017;
- Higher proposed CMI administration fees; and
- A proposed new office lease cost.[27]

Below, the Panel reviews issues related to proposed CMI and other administration fees and office lease expense, as well as the 2002–2006 deferred return, deemed interest and allowed ROE included in the 2021 forecast Revenue Requirement.

CMI and Other Administration Fees

For 2021, Stargas forecasts that CMI administration fees increase approximately $20,000, or 43 percent, compared to the 2017 approved amount. Table 2 below outlines the proposed 2021 forecast CMI administration fees by component compared to the 2017 approved revenue requirement:

Table 2: 2021 Forecast CMI and Other Administration Fees[28]

	2017 Approved			2021 Forecast		
Component	**Hours**	**Hourly Rate ($)**	**Approved Cost ($)**	**Hours**	**Hourly Rate ($)**	**Forecast Cost ($)**
Administrative	642	24.46	$ 15,703	548	29.00	$ 15,892
Bookkeeping	226	46.16	10,432	222	49.69	11,031
Accounting	102	69.24	7,062	216	74.54	16,101
Executive	94	144.26	13,560	94	155.30	14,598
Regulatory	n/a	n/a	-	24	225.00	5,400
CMI Fees	**1,064**		**$ 46,758**	**1,104**		**$ 63,022**
Fees paid to IEC			-			1,200
Contingency			-			2,521
CMI and Other Adminstration Fees			**$ 46,758**			**$ 66,743**

Stargas proposes to reclassify certain hours approved in each category outlined in the 2017 RRA Decision and to add an incremental 40 hours to the total hours.[29] Stargas also requests inflationary increases to the hourly rate for each of the previously approved CMI hourly rate categories[30] as well as other changes to the annual management fee structure, as follows:

- Addition of an "Executive – Regulatory" hourly rate category of $225.00 per hour;
- Addition of a fixed annual retainer fee of $1,200 to be paid to Independent Energy Consultants Ltd. (IEC); and
- Addition of $2,521 related to "contingency" which is equivalent to 4 percent of the management fees otherwise payable. [31]

Stargas justifies a higher hourly rate for Executive – Regulatory is warranted arguing that Mr. Blumes's many years of regulatory experience should entitle him to an hourly rate that is comparable to the rates routinely sought and approved for accountants and lawyers appearing before the BCUC[32] as set out in the BCUC PACA Guidelines.[33]

[27] Exhibit B-2, pp. 1–2.
[28] Exhibit B-1-1, pp. 6, 11; Exhibit B-6, BCUC 4.1.
[29] Ibid., p. 10.
[30] For the Administrative rate category, Stargas also seeks a "value increment" of $2.67 per hour which is in addition to an inflationary increase (Exhibit B-1-1, pp. 11-12).
[31] Exhibit B-1-1, p. 11; Exhibit B-6, BCUC IR 4.2.
[32] Exhibit B-6, BCUC IR 5.2.2.
[33] https://www.bcuc.com/Documents/Guidelines/2021/G-97-17_BCUC_PACA-Guidelines.pdf

To support the proposed retainer for IEC services, Stargas explains that the principal of IEC will serve on Stargas' board of directors to ensure a smooth transfer of executive responsibility from Mr. Blumes to Mr. Iles as the former anticipates withdrawing from all but regulatory engagement in 2021.[34] Stargas forecasts that the board of directors will meet three times per year, for approximately two or three hours per meeting.[35]

Acknowledging that the BCUC had previously denied[36] a contingency on hours for management services in the 2017 RRA Decision, Stargas also submits that a management fee contingency is warranted for 2021 because the utility continues to experience circumstances requiring management oversight which are not contemplated within "the regular routines in management." Stargas submits that applying a percentage increment to the management fees otherwise payable, as a contingency, is a lower-cost alternative to applying to the BCUC approval for recovery of unanticipated management fees to address meter malfunction, damage incidents and "like events."[37]

Office Lease Expense

For 2021, Stargas seeks approval to include a new office lease expense of $6,240 in the 2021 forecast Revenue Requirement.[38] Stargas states that its proposal is based on the BCUC's decision regarding another regulated utility, in which the BCUC found an office rent expense "is reasonably necessary to operate a utility."[39] Stargas submits that a total cost of approximately $520 per month or $6,240 per year is reasonable compensation for the offices maintained in each of Mr. Blumes and Mr. Iles' homes.[40]

In support of this amount, Stargas estimates that lease rates for equivalent space in Kelowna range from $300 to $340 per month per office, such that the "value" or savings from the two home offices is approximately $80 to $160 per month as compared to the leased space.[41] Stargas also calculates that the proposed office lease amount is reasonable considering that pro-rated property tax, insurance and utility costs for each home office is approximately $39 per month. Therefore, the lease cost or rent equivalent embedded in the proposed office lease expense is approximately $221 per month per office or "a modest $3.24 per square foot."[42]

Amortization of 2002–2006 Unrecognized Return

The 2021 forecast Revenue Requirement includes amortization of $6,974 relating to the BCUC's 2012 decision[43] allowing Stargas to amortize $135,887 in 2002-2006 unrecognized return over 20 years. The $135,887 amount was the total accumulated return on equity that had not been included in Stargas' revenue requirement between 2002 and 2006. Commencing in 2013, Stargas has recovered $6,974 each year leaving a balance of $71,909[44] to be recovered in future rates until it has been fully recognized in 2033.[45]

Deemed Interest and Allowed ROE

Stargas' 2021 forecasts deemed interest and ROE of $12,979 (recalculated below to be $12,877) and $21,735, respectively, using the deemed capital structure, allowed ROE and deemed interest rate set in the 2017 RRA

---

[34] Exhibit B-6, BCUC IRs 4.2, 4.5.
[35] Exhibit B-10, BCUC IR 27.1.
[36] 2017 RRA Decision, p. 13.
[37] Exhibit B-1-1, p. 13; Exhibit B-6, BCUC IR 4.3.
[38] Ibid., p. 3.
[39] Ibid.
[40] Ibid.
[41] Exhibit B-6, BCUC IR 3.3.
[42] Ibid, BCUC IR 3.2; Exhibit B-10, BCUC IRs 25.2, 25.2.1.
[43] Order G-157-12 dated October 25, 2012.
[44] Exhibit B-1-1, p. 24. The balance remaining is calculated as the balance outstanding at October 31, 2020 of $78,703 less 2021 amortization of $6,794 = $71,909 (Exhibit B-1-1, p. 25).
[45] 2017 RRA Decision, pp. 20–21.

Decision.[46] Table 3 below shows a recalculation of the deemed interest and ROE based on the finalized forecast of the mid-year rate base. The Panel makes no adjustment to the proposed Revenue Requirement for the insignificant difference in deemed interest.

Table 3: Calculation[47] of 2021 Forecast Deemed Interest and Allowed ROE

2021 forecast Mid-Year Rate Base[48]	$538,333
Debt component	57.5%
WACD	4.16%
Deemed interest	**$12,877**
Equity component	42.5%
ROE	9.50%
Allowed ROE	**$21,735**

Positions of the Parties

SSPOA states that does not object to the 2021 delivery rate as proposed since it supports the approval of the Asset Disposition Application. Notwithstanding, SSPOA notes that it would have otherwise challenged, among other things, the forecast CMI management fees and amortization related to software that may never be used.[49]

Panel Determination

Subject to the adjustments to regulatory accounts as determined in Section 3 of this Decision, and for CMI, other administration fees, and office lease costs noted below, the Panel finds the 2021 forecast Revenue Requirement reflected in Table 1 provides a reasonable basis for setting the 2021 delivery rate. Apart from CMI administration fees and office lease, other forecast O&M costs are comparable to recent actual expenditures, and any variances are supported by sufficient evidence. Forecast deemed interest and allowed ROE amounts are based on the deemed capital structure and allowed ROE as determined in the 2017 RRA Decision. The other Revenue Requirement items are comparable to the previous periods or are sufficiently supported by reasonable explanations.

The Panel notes SSPOA's comment related to the inclusion of forecast amortization of software that is currently not in use but considers that the amount ($1,475)[50] has an insignificant impact on the 2021 forecast Revenue Requirement and delivery rate and has accepted its inclusion.

<u>CMI and Other Administration Fees</u>

The Panel finds that Stargas' proposed increase in CMI administration fees from $46,758 to $63,022, or 35 percent is not reasonable, and therefore reduces the revenue requirement by $12,682. The fees set in the 2017 RRA Decision resulted from the BCUC's detailed and extensive review of tasks necessary to operate the

[46] Exhibit B-6, BCUC IR 1.3.
[47] Calculation formula, component weightings and rates as described on pages 16 and 17 of Exhibit B-1-1 using the initial forecast mid-year rate base.
[48] Exhibit B-6, BCUC IR 9.1.
[49] SSPOA Final Argument, pp. 4, 9.
[50] Exhibit B-1-1, p. 16.

utility, as well as the determination of appropriate CMI hourly rates for the various tasks. On that basis, the BCUC established a reasonable starting point for determining CMI administration fees for 2021.

In the Panel's view, any comparison of the CMI hourly rates to the BCUC PACA Guideline hourly rates is not relevant for establishing appropriate hourly rates for CMI's services. Stargas has not provided sufficient evidence to support an increase in CMI hourly rates beyond an adjustment for inflation. Stargas has also not demonstrated that the scope of administrative and management activities has expanded by its proposed 40 incremental hours. **Accordingly, the Panel approves an increase of $3,582 to the 2017 approved CMI administration fees, amounting to an inflationary increase of approximately 7.66[51] percent, for inclusion in the 2021 Revenue Requirement and delivery rate.**

Regarding the proposed 4 percent contingency, the Panel does not agree that this is a preferrable approach to applying to the BCUC for approval to recover any non-routine or unanticipated matters that may or may not arise. Consistent with the 2017 RRA Decision, **the Panel denies Stargas' request to include a contingency of $2,521 in the 2021 Revenue Requirement and delivery rate.**

The Panel finds Stargas' proposal for a fixed annual IEC retainer fee of $1,200 is reasonable given that the principal of IEC will fulfill a newly created director role.

<u>**Office Lease Expense**</u>

The Panel finds Stargas' proposal to include a new office lease expense of $6,240 in the 2021 forecast Revenue Requirement is not warranted. Stargas' Revenue Requirement has not historically included a cost for office space and the amount proposed for 2021 does not represent incremental office lease costs expected to be incurred in 2021. Further, the Panel views that the hourly rates, which have been adjusted for inflation based on the Panel determination above, are sufficient to cover increases in CMI's overhead costs consistent with previous periods. Accordingly, **the Panel denies Stargas' request to include an office lease amount of $6,240 in the 2021 Revenue Requirement and delivery rate.**

2.2 2021 Load Forecast

Stargas forecasts the delivery of 48,250 GJ of natural gas to 363 customers for the purpose of setting 2021 Rates,[52] representing a 3.2 percent increase over actual natural gas consumption of 46,767 GJ for the 12 months ending October 31, 2020. [53] Stargas prepared the delivery forecast by averaging consumption per customer for the two previous years, multiplied by the forecast number of customers for 2021.[54] Stargas notes that temperatures recorded in each of the two prior years were relatively consistent with average winter temperatures, and it expects similar weather for winter 2020/21.[55]

Stargas includes 15 additional residential customers in its delivery forecast for 2021, with no growth in commercial customers. Stargas confirms that 20 new residential customers were added during the summer/fall 2020 construction season, but forecasts lower deliveries due to the COVID-19 pandemic equivalent to the consumption of 5 residential customers, setting the delivery forecast for 2021 at 48,250 GJ.[56] Stargas states that

[51] From page 11 of the Application and page 12 the 2017 Application, the 2017 BC CPI 2017 was 122.7 and the 2020 BC CPI was 132.1. This represents approximately 4 years of inflation, the calculated difference in BC CPI between the two data points is 7.66% (132.1-122.7/122.7).
[52] Exhibit B-1-1, p. 1.
[53] Exhibit B-6, BCUC IR 2.5.
[54] Ibid., BCUC IRs 2.1, 2.4.
[55] Ibid., BCUC IR 2.2.
[56] Ibid., BCUC IR 2.4.

there remains significant uncertainty around its load forecast arising due to the COVID-19 pandemic, noting that October 2020 deliveries were consistent with those of prior years.[57]

Positions of the Parties

No submissions were made by interveners or interested parties regarding Stargas' delivery volume forecast.

Panel Determination

The Panel finds the load forecast is reasonable for the purpose of determining the forecast revenue and revenue surplus reflected in Table 1 and for setting delivery rates for 2021. Stargas' approach incorporates a forecast of customer growth comparable to 2020 with an estimated reduction in load to reflect the uncertainty of the load as a result of the COVID-19 pandemic. The Panel agrees with Stargas that basing the load forecast on a load comparable to the 2020 actual load is reasonable given the uncertain impacts of the COVID-19 pandemic.

3.0 2021 Regulatory Accounts

Stargas proposes regulatory account treatment for 2021 costs related to regulatory activities (Regulatory Costs) as well as certain variances between 2017 Revenue Requirement approved items and actual costs incurred between 2017 and 2020 (Proposed Prior Period Interest and ROE Adjustments). Approval of regulatory account treatment means the amount recorded will be recovered from ratepayers in a future period using an amortization period and recovery mechanism to be approved by the BCUC, providing the utility with certainty of cost recovery.

As part of the BCUC's Regulatory Account Filing Checklist, the following criteria, among other things, are applied to address whether a requested deferral or regulatory account treatment is warranted:

- The extent to which the cost is within the control of management; and
- The degree of forecast uncertainty associated with the cost.[58]

In the Panel's view, if an item is reasonably controllable and forecastable, then it should form part of the forecast revenue requirement and the utility should bear the risk of any forecast variance. However, if a utility has limited control over the item, or there is a high degree of forecast uncertainty, it may not be appropriate for the utility to bear the risk of forecast variances. In such a case, the establishment of some form of variance or deferral mechanism may be appropriate.

In addition, a key consideration for the Panel regarding Stargas' requests for regulatory account treatment for variances between prior period Revenue Requirement items is the prohibition against 'retroactive ratemaking'. The Supreme Court of Canada stated in ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)[59] (ATCO decision):

> …The Board was seeking to rectify what it perceived as a historic overcompensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established

[57] Ibid., BCUC IR 2.3.
[58] Retrieved from https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf
[59] *ATCO Gas & Pipelines Ltd.* v. *Alberta (Energy & Utilities Board),* 2006 SCC 4 (CanLII), [2006] 1 SCR 140, par. 71; Retrieved from: https://canlii.ca/t/1mj7l#par71

> throughout the various provinces that utilities boards do not have the authority to retroactively change rates…[60]

Consistent with this reasoning in the ATCO decision, the BCUC typically sets rates on a prospective basis only, based on a utility's forecast COS, and the BCUC has no authority to allow recovery on a retroactive basis. The well-established exceptions to retroactive ratemaking include, in part:

- Setting of interim rates which are subject to later adjustment; and
- Recognition of amounts in deferral accounts to be carried forward to be disposed of in future years.

With these principles in mind, in the following subsections the Panel reviews each of Stargas' regulatory account requests as well as the treatment of other previous BCUC approved regulatory accounts (2018 Incident Shortfall and 2017 New Service Installations regulatory accounts).

3.1 Regulatory Costs

Stargas requests approval to establish the "2020 Delivery Rate and Regulatory Account Application regulatory account" to record forecast management costs incurred in the preparation of the Application and any further costs related to the Application.[61] The forecast costs will be trued-up to actual costs.[62] Stargas also proposes to include the management costs associated with preparing the delivery rate application withdrawn in 2019 and costs related to negotiating the current technical and administrative services agreement with FEI.[63] The costs of filing Stargas' annual commodity purchase plan and commodity rate application with the BCUC are not included in the proposal, but rather, Stagas submits these costs are captured within the forecast CMI administration fees described in subsection 2.1 because they are recurring activities.[64] In preparing the current Application, Stargas submits that it relied heavily on the September 2019 Application which was withdrawn as described in section 1.2 above.[65]

Stargas proposes that the regulatory account attract its weighted average cost of capital (WACC) return, with the amortization to be determined in a future application if the Asset Disposition Application is not approved.[66] Stargas submits that deferring the recovery of the regulatory account balance is appropriate based on the high probability of completing the sale of Stargas' assets to FEI.[67]

Table 4 outlines the proposed additions to the regulatory account and the forecast balance in the account up to the end of the first round of IRs.

[60] Ibid.
[61] For example, BCUC direct costs, Participant Assistance/Cost Award (PACA) costs.
[62] Exhibit B-1-1, pp. 29–30; Exhibit B-10, BCUC IR 35.2.2.
[63] Ibid., pp. 30, 32.
[64] Exhibit B-6, BCUC IR 5.2.
[65] Exhibit B-1-1, p. 30.
[66] Ibid., pp. 1, 29.
[67] Exhibit B-8, Confidential BCUC IR 5.1.

Table 4: 2020 Delivery Rate and Regulatory Account Application Regulatory Account

2020 Delivery Rate and Regulatory Account Application Regulatory Account	Proposed Cost ($)
September 2019 CMI Application Costs[68]	$25,841
September 2020 CMI Application Costs[69]	5,741
Securing Contracted Services[70]	6,876
Responses to BCUC and SSPOA IR1[71]	3,042
Responses to Confidential BCUC IR[72]	750
Closing Balance	**$42,250**

In its final argument, Stargas states the costs incurred to date[73]were higher than the $42,250 noted above and that CMI management incurred costs of $3,153, resulting in a revised expected addition of $45,303 to the regulatory account.[74]

Stargas also states that it is unable to forecast the amount of BCUC direct costs or PACA costs for the proposed account.[75]

In the 2017 RRA Decision, the BCUC approved a similar deferral account to record the costs of that proceeding, which included estimates for Stargas legal counsel and management time, actual BCUC expenses and PACA awards, totalling $41,450 as follows:

Table 5: 2016 Delivery Rate Application Regulatory Costs[76]

2016 Delivery Rate Application Regulatory Account	Approved Cost ($)
Legal	$16,500
CMI management time	$13,853
BCUC expenses	$2,180
PACA awards	$8,568
	$41,450

Panel Determination

The Panel finds Stargas' forecast CMI regulatory costs for the 2021 Revenue Requirement Application of $42,250 are not reasonable. Stargas proposes total CMI regulatory costs of approximately $35,000[77] plus an additional $3,100 noted in its final argument compared to the 2017 approved CMI regulatory costs of $13,853. While an inflationary increase over 2017 is warranted, the complexity of the 2021 RRA and related regulatory process is not reflective of such a large increase in effort. **Accordingly, the Panel limits the forecast CMI regulatory costs included in the 2021 Revenue Requirement to $17,500, representing approximately 50 percent of the proposed amount, a reduction of $17,874.**

---

68 Exhibit B-1-1, p. 31.
69 Ibid., p. 30.
70 Ibid., p. 32.
71 Exhibit B-6, BCUC IR 21.6.1.
72 Ibid., BCUC IR 21.6.1.
73 Stargas states in page 2 of the Final Argument that the total costs incurred are to February 28, 202 [*sic*].
74 Stargas Final Argument, p. 2.
75 Exhibit B-6, BCUC IR 21.6.1.
76 Ibid., BCUC IR 21.6.1.
77 Derived from Table 4: $25,841+5,741+3,042+750 equals $35,374 or approximately $35,000.

The Panel denies Stargas' request to record the approved 2021 CMI regulatory costs in a regulatory account and to defer the recovery mechanism until a future application. The recovery of 2021 regulatory costs is unrelated to the potential sale of Stargas' assets to FEI. Given the proposed reduction in the 2021 delivery rate, the Panel sees no regulatory justification, such as the need to smooth in rate increases, for deferring these costs to a future period. **Accordingly, the Panel directs Stargas to include $17,500[78] of forecast 2021 CMI regulatory costs in the 2021 Revenue Requirement and 2021 delivery rates.**

The Panel denies Stargas' proposal to classify and recover the $6,876 costs of negotiating the current FEI technical and administrative services agreement as regulatory costs. Contract negotiations are normal course administrative activities, and costs of this nature are inherently included in the approved CMI administration fee. Further, to the extent that this effort occurred in Fiscal 2020, the Panel notes that even after the adjustment for the BCUC 2017 New Service Installations Regulatory Account noted below (section 3.4), Stargas' additional earned return was significantly higher than its allowed return as noted in Table 1 above.

The Panel approves the establishment of a 2021 Delivery Rate and Regulatory Account Application account to capture any BCUC direct costs and other third-party costs related to the Application. The non-rate base regulatory account is approved to attract interest based on a WACC return and the amortization or recovery mechanism is to be determined in the next RRA. Variance treatment for BCUC and third-party costs related to the Application is consistent with previous BCUC decisions. These costs are outside Stargas' control and are difficult to estimate. The Panel notes that SSPOA stated that it will not be submitting any expenses towards the proceeding.[79]

3.2 Proposed Prior Period Interest and ROE Adjustments

In the 2017 RRA Decision, the BCUC directed that, effective November 1, 2016, Stargas' allowed return be calculated on what was referred to as a 'conventional basis'.[80] This refers to providing a utility the opportunity to earn a fair return based upon a deemed capital structure and ROE.[81]

The BCUC found that using a conventional method of calculating Stargas' ROE was more transparent, efficient, and easier for all parties to understand. In addition, the BCUC noted Stargas' submission that its proposed return on invested capital would not be materially different than if it had been calculated using a more conventional mechanism.[82]

The BCUC set Stargas' deemed capital structure at 57.5 percent debt and 42.5 percent equity and the allowed ROE at 75 basis points above the BCUC benchmark cost of capital. In addition, for the purposes of determining deemed interest for the debt component, the BCUC calculated Stargas' fiscal 2017 weighted-average cost of debt (WACD) of 4.0 percent based on a weighted average of its operating line, long term debt and shareholder loans. The resulting amounts included in the 2017 approved Revenue Requirement was deemed interest and ROE of $11,567[83] and $20,306,[84] respectively.[85]

[78] Derived from Table 4: $42,250-17,874-6,876 equals $17,500.
[79] Exhibit C1-4, SSPOA IR 1.10.
[80] 2017 RRA Decision, p. 21.
[81] Ibid., p. 19.
[82] Ibid., p. 20.
[83] Calculated as: 2017 forecast mid-year rate base of $502,928 x 57.5% debt ratio x 4.0% WACD = $11,567 (2017 RRA Decision, p. 21.)
[84] Calculated as: 2017 forecast mid-year rate base of $502,928 mid-year rate base x 42.5% equity ratio x 9.5% ROE = $20,306 (2017 RRA Decision, p. 21).
[85] 2017 RRA Decision, p. 21.

Interest Deficit

For 2021, Stargas requests approval to establish a regulatory account to recover an 'interest deficit' of $18,005 for the period June 1, 2017 to October 31, 2020, with the regulatory account proposed to earn interest at the WACC.[86]

Stargas submits that the regulatory model upon which deemed interest costs were set in the 2017 RRA Decision failed to provide for a recovery of its actual costs. Since actual interest costs incurred in financing the utility's capital and operating costs can be readily determined, Stargas argues that actual costs should have been included in its annual revenue requirement instead of the deemed interest estimate.[87]

Undistributed ROE

Stargas also requests approval to establish a regulatory account to recover 'undistributed ROE' of $69,379 for the period June 1, 2017 to October 31, 2020, stating that distributions to shareholders of the allowed ROE were withheld to limit further increases in the interest deficit for the same period, as discussed above.[88]

Stargas submits that the proposed regulatory account be amortized over a period of twenty years, if the sale of Stargas assets to FEI is not completed.[89]

Panel Determination

The Panel denies Stargas' request to establish regulatory accounts to recover the proposed 'interest deficit' and 'undistributed ROE' amounts for the period June 1, 2017 to October 31, 2020.

Stargas' request regarding the 'interest deficit' would result in retroactive ratemaking, therefore the Panel denies this proposal. As noted above, a key consideration for the Panel regarding Stargas' requests for regulatory account treatment for items approved in the 2017 RRA Decision is the prohibition against retroactive ratemaking. In the 2017 RRA Decision, deemed interest was set on a prospective basis and deferral or variance treatment was not approved. Since the 2017 RRA Decision set the delivery rate on a permanent basis and a deferral account was not established, the BCUC cannot now retroactively change the rate paid by ratepayers. The BCUC could only do so if there was a deferral account or if the rates were set on an interim basis.

Since this proposal is denied, the Panel has not reviewed the interest variance amounts presented by Stargas to determine if the amount appropriately represents the difference between deemed and actual interest expense for the period June 1, 2017 to October 31, 2020.

Stargas' request regarding 'undistributed ROE' is without merit and would result in retroactive ratemaking, therefore the Panel denies any adjustment to the 2017 deemed capital structure in 2021. Regarding the merits of the request, the Panel notes that delivery rates for the period June 1, 2017 to October 31, 2020 already included recovery of the allowed ROE. The request to record the ROE in a regulatory account for future recovery would amount to ratepayers paying the amounts again. In addition, even after the adjustment for the BCUC 2017 New Service Installations Regulatory Account noted below, Stargas' additional earned return for 2019 and 2020, as set in Table 1 above, significantly exceeded its allowed return.

The fact that the ROE for the period June 1, 2017 to October 31, 2020 was not distributed to the shareholder, is only relevant for comparing the actual capital structure to the approved deemed capital structure and does not

[86] Exhibit B-1-1, pp. 33, 29.
[87] Ibid., p. 33; Exhibit B-6, BCUC IR 22.1.
[88] Exhibit B-1-1, p. 35; Exhibit B-6, BCUC IR 22.3.
[89] Ibid., p. 35; Exhibit B-10; BCUC IR 28.2.

negate the fact that the ROE has been earned by the shareholder. Similar to the Panel's discussion of deemed interest above, the BCUC set the 2017 deemed capital structure on a prospective basis and did approve regulatory or deferral treatment such that impact of variances between deemed capital structure and actual capital structure could be captured in a regulatory account to be carried forward to be recovered in future rates. Any subsequent adjustment in 2021 for the differences between the deemed and actual capital structure, such as the non-payment of dividends which might result in a higher equity component, would result in retroactive ratemaking.

3.3 2018 Incident Shortfall Regulatory Account

In 2018, the BCUC approved the establishment of a regulatory account to record the actual costs incurred in excess of recoveries associated with a June 6, 2017 line break incident (Incident Shortfall Regulatory Account), with interest applied at Stargas' approved WACC.[90] Stargas was directed to file supplemental information as part of its 2019 delivery rate application, including clarification of the incident location, actions taken, nature of the costs incurred, discussion of Stargas' contractual relationship with FAES, discussion of potential recovery mechanisms, and supporting documentation for costs incurred.[91] As the BCUC approved the withdrawal of the Stargas' 2019 delivery rate application as noted in section 1.2 above, Stargas has addressed the supplemental information directives as part of this Application.

Stargas requests approval to recover incident shortfall costs of $16,687 as set out in the following table:

Table 6: 2018 Incident Shortfall Regulatory Account[92]

	Costs ($)
FAES – Final Settlement July 5, 2018	$9,082
Five Star Utility Relights	650
Stargas Meter Reader – Relight Status	190
Executive Time (M.A. Blumes – 30.5 hours)	4,400
Interest at WACC (July 5, 2018 – October 31, 2020)[93]	2,365
Total before Amortization	**$16,687**

Stargas explains that the line break incident occurred on an FEI main outside of the Stargas service area. Direct costs claimed represent the regasification of service to Silver Star and subsequent customer relights. Given that the damage was not to a Stargas main, Stargas did not have direct contact with the party that caused the damage, instead relying exclusively on the assistance of FAES.[94]

The $9,082 FAES settlement amount arises from the difference between $74,477 in direct costs incurred by FAES in response to the incident on behalf of Stargas and the settlement amount obtained from the insurer of the party that caused the damage. Stargas submits that it pursued a further reduction in this shortfall, but when faced with the potential costs of legal representation to initiate an independent claim against the party causing the damage, it determined that accepting the $9,082 shortfall was expedient.[95]

Stargas explains that executive time represents 30.5 hours of executive time related to management of the incident response and related regulatory costs at an hourly rate of $144.26.[96]

---

[90] Order G-159-18 and Reasons for Decision dated August 27, 2018.
[91] Ibid., Reasons for Decision, pp. 4–5.
[92] Exhibit B-1-1, p. 26.
[93] Derived from $823+452+636+453 equals $2,365, where WACC ranged from 6.28% to 7.12% for the period, per Exhibit B-1-1, p. 26.
[94] Exhibit B-1-1, p. 26-27.
[95] Ibid., p. 27.
[96] Ibid., pp. 28–29. The number of hours of executive time calculated as 12.5+15.25+8-5.25 hours equals 30.5 hours.

While Stargas seeks approval to establish the costs as recoverable, it does not propose to recover the amounts from ratepayers in 2021. Stargas submits that it would only seek to establish a recovery mechanism if its sale of regulatory assets and operations to FEI fails to complete.[97]

Of the potential recovery mechanisms for the Incident Shortfall Regulatory Account balance, Stargas submits that it would favour using a rate rider to recover the balance with an amortization period over 12 or 24 months. Stargas notes that a $0.3551 rate rider would allow for recovery within 12 months, or $0.18322 for recovery within 24 months.[98]

Positions of the Parties

SSPOA notes that it would be challenging Stargas' rate rider proposal covering the incident shortfall costs if it were not for the proposed sale of Stargas regulatory assets and operations to FEI.[99]

Panel Determination

The Panel approves the addition of $16,687 in incident related costs to the previously approved 2018 Incident Shortfall regulatory account. The incident and related costs incurred were outside the control of management and the amounts recorded in the regulatory account are supported by sufficient evidence and reasonable explanations.

The Panel disagrees with Stargas' request to defer recovery of the 2018 Incident Shortfall regulatory account until a future period. The recovery of this amount is unrelated to the potential sale of regulatory assets and operations to FEI. Since there is a proposed reduction in the 2021 delivery rate, the Panel sees no regulatory justification, such as the need to smooth-in rate increases, for deferring these costs to a future period. Further, given that the recognition of the total amount in 2021 is more than offset by other positive adjustment as set out in Table 8 below, the Panel views that establishing a rate rider for recovery of the amount would be administratively inefficient. **Accordingly, the Panel directs Stargas to include amortization of the $16,687 related to the 2018 Incident Shortfall regulatory account in the 2021 Revenue Requirement and 2021 delivery rate.**

3.4 2017 New Service Installations Regulatory Account

In 2017, the BCUC approved a revised policy for Stargas' new service installations. Under this policy, Stargas pays the new service installation costs and records the costs in rate base, net of a $25 installation fee charged to each new customer. Previously, new customers were responsible for paying the installation costs.[100] Several issues were identified in the current proceeding related to Stargas' accounting for new service installations and related revenues under this revised policy, which are discussed below.

<u>Background</u>

During the 2017 proceeding, Stargas anticipated the following benefits would result from the new service installation policy:

- Incremental volume increases would benefit existing Stargas ratepayers;
- Propane consumers that convert to Stargas would benefit from reduced energy costs; and

[97] Ibid., p. 26.
[98] Exhibit B-6, BCUC IR 18.1.1.
[99] SSPOA Final Argument p.9.
[100] Order G-164-17 and the accompanying Reasons for Decision dated November 9, 2017.

- Stargas would benefit from increases in rate base generating additional returns to its shareholder.[101]

The BCUC stated that the revised policy:

> …will reduce the upfront investment by new residential and small commercial customers, potentially encouraging customers to switch to using Stargas' services. Further, the evidence indicates that under the proposed changes, each new residential and small commercial customer taking service from Stargas will contribute a positive net revenue margin to Stargas' revenue requirement, thus not disadvantaging existing customers.[102]

Since Stargas did not propose any changes to its 2017 delivery rate of $5.77 per GJ to reflect any incremental volumes and changes to forecast revenues and costs due to the revised policy, the BCUC directed Stargas to establish a regulatory account to capture the incremental revenues and costs associated with the new service installations added prior to November 1, 2019. The BCUC also directed Stargas to include its proposed disposition of the account as part of the next RRA[103] which was to be filed by July 31, 2019.[104] However, as noted in section 1.2, Stargas was granted an extension to file its next delivery rates application for rates effective November 1, 2020.

2021 Issues

Stargas confirms that it did not create the BCUC directed regulatory account to record the incremental revenues and costs for new service installations. Instead, the incremental revenues and costs were included in Stargas' income and recognized as additional earned return to the benefit of the shareholder.[105]

As part of the information request (IR) process, Stargas was asked to provide an estimate of the incremental revenues and costs associated with new service installations for each year between 2018 and 2020.[106] Stargas estimates the total net revenues attributable to new customers to be $18,745 through October 31, 2021, based on average annual consumption, plus the revenue collected from a monthly fee of $15 per month per customer.[107] However, Stargas notes that the data provided is not as definitive as would be required to establish a regulatory account.[108] In a separate IR response, Stargas also provided another estimate of the net incremental revenues from new customer additions to be approximately $222, $391 and $393 per customer for the years ended May 31, 2019, May 31, 2020 and the period from May 31, 2020 to October 31, 2020, respectively.[109]

Stargas submits that a BCUC determination regarding the regulatory account balance and the disposition of the account should be deferred until after the BCUC issues its decision regarding the transfer of Stargas assets to FEI and should only be required if Stargas continues to own and operate the utility assets.[110]

Stargas also confirms that it did not record the $25 installation fee charged to new customers as an offset to rate base and instead recorded these amounts in sundry revenue. Stargas submits that these amounts are not material and therefore no adjustment to rate base is required.[111] Based on the number of new service

---

[101] Ibid., p. 4.
[102] Ibid., p. 5.
[103] Order G-164-17, Directive 3.
[104] 2017 RRA Decision, p. 25.
[105] Exhibit B-6, BCUC IR 17.1.1.1.
[106] Ibid., BCUC IR 17.2 and Exhibit B-10, BCUC IR 33.3.
[107] Ibid., BCUC IR 17.2, based on incremental revenues of $1,683, $13,478, and $10,109 and incremental costs of $435, $3,480, and $2,610 for the years ending October 31 2018, 2019, and 2020, respectively.
[108] Exhibit B-10, BCUC IR 33.3.
[109] Ibid.
[110] Ibid., BCUC IR 33.4.
[111] Ibid., BCUC IR 33.5.1

installations[112] provided by Stargas, the revenue related to the $25 installation fee between June 1, 2018 and October 31, 2020 is estimated to be $1,975.[113]

Position of the Parties

SSPOA does not directly address Stargas' accounting for new service installations since the revised policy came into effect. However, SSPOA argues that the one year delay in filing the current delivery rates application denied ratepayers the benefit of the increased gas consumption since 2017, amongst other things.[114] In Reply, Stargas submits that SSPOA fails to address other factors that would have increased delivery rates during the same period.[115]

Panel Determination

The Panel finds that Stargas is not in compliance with the BCUC directive to establish a regulatory account to capture the incremental revenues and costs associated with the new service installations. Further, this account should have remained in effect until the filing of its next RRA (this Application). Establishment and continuity of this regulatory account were appropriate given the expectation that the change in the extension policy could result in an increase in the load that was not reflected in the load forecast or the approved delivery rate.

Regulatory account treatment ensures that ratepayers benefit from the incremental revenues less costs until the ongoing impact of the new policy can be reflected in an updated load forecast and delivery rate. Accounting for these incremental amounts in compliance with the BCUC directive partially addresses the concerns raised by SSPOA that the one year delay in filing this Application denied ratepayers the benefit of the increased gas consumption to the extent that the increase in consumption since 2017 resulted from new installations during that period.

The Panel also notes SSPOA's comment that the extension granted to Stargas related to the filing of this Application also delayed the recognition of expired depreciation as a reduction in the delivery rate.[116] However, since the BCUC did not establish interim rates at the time it approved the delay in the application, the BCUC's approved 2017 delivery rate remains in effect until a new rate is set in this proceeding. This is consistent with the prohibition against retroactive ratemaking discussed previously.

The Panel disagrees with Stargas' position that the requirement to establish a regulatory account should be deferred. Allocation of the benefit of the incremental revenues and costs to ratepayers is unrelated to the potential sale of regulatory assets and operations to FEI.

While Stargas has declined to provide a 'definitive' estimate, a reasonable estimate of the credit to be allocated to ratepayers can be made based on the evidence filed during the proceeding. Using the evidence noted, the following table details the Panel's calculation of an appropriate amount to be reflected as additions to the New Services Installations Regulatory Account assuming new customer additions in each year are added halfway through the year.

---

112 The number of new service installations is 32, 26 and 21 for the periods ending May 31, 2019, May 31, 2020, and October 31, 2020, respectively, per Exhibit B-10, BCUC IR 33.3.

113 Period ended May 31, 2019 = 32 x $25 = $800 / Period ended May 31, 2020 = 26 * $25 = $650 / Period ended May 31, 2021 = 21 x $25 = $525 / Total = $800 + $650 + $525 = $1,975

114 SSPOA Final Argument, p. 5.

115 Stargas Reply Argument, p. 6.

116 SSPOA Final Argument, pp. 5–6.

Table 7: BCUC 2017 New Service Installations Regulatory Account

Component**	12-months May 31, 2019	12-months May 31, 2020	5-months Oct 31, 2020
Number of New Customer Additions[1]	32	22	20
Cumulative New Customer Additions[2]	16	43	64
Average consumption (GJs) per New Customer [3]	71.0	75.0	15.0
Delivery Rate per GJ[4]	$ 5.77	$ 5.77	$ 5.77
Incremental Revenue			
Incremental Variable Revenue from New Customers (Rounded)[5]	$ 6,000	$ 18,000	$ 6,000
Incremental Fixed Revenue from New Customers (Rounded)[6]	$ 3,000	$ 8,000	$ 12,000
Total Incremental Revenue	**$ 9,000**	**$ 26,000**	**$ 18,000**
Incremental Costs			
Incremental Operating Costs			
Incremental Variable Charges for Contracted Services (Rounded)[7]	$ 3,000	$ 3,000	$ -
Incremental CMI Administrative Fees (Rounded)[8]	$ -	$ -	$ -
Incremental Rate Base Costs			
Approximate Rate Base Installation Costs (Rounded) [9]	$ 46,000	$ 32,000	$ 16,000
Cumulative Approximate Rate Base Installation Costs (Rounded) [10]	$ 23,000	$ 62,000	$ 86,000
Incremental Amortization Expense From Cumulative Rate Base Installation Costs (Rounded)[11]	$ 1,000	$ 2,000	$ 2,000
Stargas WACC [12]	6.43%	6.43%	6.43%
Incremental Return on Cumulative Rate Base Installation Costs (Rounded)[13]	$ 1,000	$ 4,000	$ 6,000
Total Incremental Costs	**$ 5,000**	**$ 9,000**	**$ 8,000**
Incremental Revenues Less Incremental Costs	**$ 4,000**	**$ 17,000**	**$ 10,000**
Regulatory Account Balance, beginning of year	$ -	$ 4,000	$ 21,000
Regulatory Account Balance, end of year	**$ 4,000**	**$ 21,000**	**$ 31,000**

** All $ Figures except the Delivery Rate per GJ are Rounded to the Nearest Thousand

(1) Stargas provided different estimates of new customer additions in response to BCUC IRs 2.1, 17.2 and 33.3. For the purposes of this calculation, the lower and more conservative estimate is used, which is 22 and 20 new customers for the 12 months ended May 31, 2020 and 5 months ended October 31, 2020, respectively.

(2) For the purposes of calculating incremental revenue and operating expenses, this is the total new customer additions from the previous year and 1/2 of the new customer additions from the current year.

(3) Provided in Exhibit B-6, BCUC IR 2.1 for the 12 months ended May 31, 2019 and May 31, 2020, respectively. For the purposes of this calculation, the average consumption per new customers for the 5 months ended October 31, 2020 is based on the 2021 load forecast for the months of June to October in Exhibit B-1-1 on p. 38.

(4) Order G-164-17 dated November 9, 2017

(5) Calculated as the cumulative new customer additions multiplied by the average consumption per customer multiplied by the delivery rate per GJ.

(6) Calculated as the cumulative number of new customer additions multiplied by a Basic charge of $15 per month multiplied by the number of months.

(7) Calculated based on the cumulative new customer additions and consumption per customer, the variable charges for contracted services cost are $15/month/customer plus $1.49/GJ delivered up to December 1, 2019 and $1.49/GJ delivered thereafter per Exhibit B-6, BCUC IR 17.2 and Exhibit B-1-1, p. 2. When rounded to the nearest thousand, this is $0 for the months ended October 31, 2020.

(8) Calculation assumes $5/customer rather than $5/year per Exhibit B-10, BCUC IR 33.3. When rounded to the nearest thousand, this is $0.

(9) From Exhibit B-6, BCUC IR 9.1 with the modification to the 5-months ended October 31, 2020 provided in response to Exhibit B-10, BCUC IR 29.1.

(10) For the purposes of calculating incremental amortization expense and incremental return on rate base, this is the total incremental rate base installation costs from the previous year and 1/2 of the rate base installation costs from the current year.

(11) Calculated as the cumulative rate base installation costs divided by the 40 year amortization period for distribution grid assets per Exhibit B-1-1, p. 15.

(12) WACC based on Table 3 of the decision: (4.16% WACD * 57.5% debt component) + (9.5% ROE * 42.5% equity component).

(13) Calculated as the cumulative incremental rate base installation costs multiplied by the Stargas WACC.

Based on the calculation detailed in Table 7 above, the Panel directs Stargas to record a credit of $31,000 in the New Services Installations Regulatory Account and to amortize the credit to the 2021 Revenue Requirement and 2021 delivery rate. As detailed in section 4 below, recognition of this credit in the 2021 delivery rate credit effectively offsets the inclusion of the forecast regulatory costs and amortization of 2018 Incident Shortfall regulatory account and there is still an overall reduction in the 2021 delivery rate. As a result, the Panel sees no regulatory justification, such as the need to smooth in rate increases, for deferring recognition of this ratepayer credit to a future period.

The Panel notes that Stargas did not comply with the BCUC directive to record the $25 installation fee charged to new customers as an offset to rate base but agrees with Stargas that the impact on deemed interest and ROE is not significant.

4.0 Setting the 2021 Delivery Rate

Positions of the Parties

As noted previously, based on its 2021 forecast Revenue Requirement of $221,235 and 2021 load forecast of 48,250 GJ of natural gas, Stargas requests approval of a permanent decrease in the delivery rate of $1.18 per GJ to $4.59 per GJ, effective November 1, 2020.[117]

SSPOA submits that it supports "the potential of eliminating retroactive billings" based on its understanding that the Stargas ratepayer will continue paying the interim rate until closing of the Stargas sale to FEI and then transfer seamlessly to becoming an FEI customer.[118]

SSPOA also submits that the sale of Stargas' regulated assets to FEI changes the focus of this proceeding and as a result of its support for the acquisition of Stargas' regulated assets by FEI, it does not object to the provisions of the proposed delivery rate.[119]

Panel Determination

In sections 2 and 3 of this Decision, the Panel makes several findings and determinations that impact the proposed Revenue Requirements and the permanent delivery rate, as summarized in the following table:

[117] ExhibitB-6, BCUC IR 1.3; Stargas Final Argument, p. 1.
[118] SSPOA Final Argument, p. 6.
[119] Ibid., p. 4.

Table 8: Final Revenue Requirement, Revenue Surplus and Approved Delivery Rate

	Revenue Requirement	Revenue (Surplus)
2021 Proposed	**$221,235**	**$(57,168)**
Disallowed Incremental CMI Administration Fees	(12,682)	(12,682)
Disallowed CMI Administration Fee Contingency	(2,561)	(2,561)
Disallowed Office Lease Costs	(6,240)	(6,240)
Recognition of Forecast Regulatory Costs	17,500	17,500
Amortization of 2018 Incident Shortfall Regulatory Account	16,687	16,687
Amortization of the 2017 New Service Installations Regulatory Account	(31,000)	(31,000)
2021 Approved	**$202,939**	**$(75,464)**
2021 Approved Load Forecast	48,250 GJ	48,250 GJ
Reduction compared to 2017 Delivery Rate per GJ		$(1.56)
2021 Approved Delivery Rate per GJ	**$4.21**	

Based on the above calculations, **the Panel approves a delivery rate of $4.21 per GJ for all ratepayers on a permanent basis, effective November 1, 2020. Stargas is directed to refund to ratepayers the difference between interim and permanent delivery rates, with interest at the average prime rate of Stargas' principal bank for the most recent year, at the same time the difference between interim and permanent commodity rates is recovered from ratepayers pursuant to Order G-133-21.**

Regarding SSPOA's comment related to retroactive billings, given the 37 percent decrease in the permanent delivery rate compared to the 2021 interim and 2017 delivery rate, the Panel considers it appropriate to direct Stargas to issue a refund to ratepayers. Processing this refund with the difference between interim and permanent commodity rates will mitigate the BCUC approved increase in commodity rate in its decision issued on May 3, 2021.[120]

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of May 2021.

Original signed by:

C. M. Brewer
Panel Chair / Commissioner

Original signed by:

K. A. Keilty
Commissioner

Original signed by:

B. A. Magnan
Commissioner

[120] Stargas Natural Gas Purchase Plan and Commodity Rate Application Effective November 1, 2020, Decision and Order G-133-21 dated May 3, 2021.

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-158-21

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

and

Stargas Utilities Ltd.
Delivery Rate and Regulatory Account Application
Effective November 1, 2020
(2021 Revenue Requirements Application)

BEFORE:
C. M. Brewer, Panel Chair
K. A. Keilty, Commissioner
B. A. Magnan, Commissioner

on May 25, 2021

ORDER

WHEREAS:

A. On September 22, 2020, Stargas Utilities Ltd. (Stargas) filed an application to the British Columbia Utilities Commission (BCUC) seeking interim and permanent approval to decrease its delivery rate from $5.77 per gigajoule (GJ) to $4.59 per GJ, effective November 1, 2020, among other requests (Application);

B. In 2017, by Order G-164-17 dated November 9, 2017, the BCUC approved, among other things, modifications to Stargas' tariff and the regulatory accounting treatment for new residential and small commercial service installation costs. The BCUC directed Stargas to capture the incremental revenues and costs associated with the new service installations in a regulatory account and to propose the disposition of this account as part of Stargas' next revenue requirements application for a delivery rate effective November 1, 2019, which was to be filed by July 31, 2019;

C. In 2018, by Order G-159-18 dated August 27, 2018, the BCUC approved, among other things, the establishment of a 2018 Incident Shortfall regulatory account to record the actual incident costs incurred in excess of recoveries associated with line break incident on June 6, 2017, stating the review and approval of the costs and determination of the recovery mechanism will be considered in the review of Stargas' 2019 delivery rate application, which was to be filed by July 31, 2019;

D. By letters L-54-19, L-17-20 and L-55-20, the BCUC approved extensions to the filing deadline for Stargas' delivery rate application from July 31, 2019 to September 30, 2020;

E. By Order G-272-20 dated January 21, 2021, the BCUC directed, among other things, Stargas to maintain its existing delivery rate for all customers on an interim and refundable basis, effective November 1, 2020. The BCUC also directed that any variance between the interim rates and permanent rates as determined at the time the BCUC renders its final decision on the Application will be refunded to or collected from ratepayers, with interest at the average prime rate of Stargas' principal bank for the most recent year;

F. By Orders G-272-20, G-328-20 and G-22-21, the BCUC established and furthered a regulatory timetable for the review of the Application, which included Stargas filing supplementary information, intervener registration, two rounds of BCUC and intervener information requests (IRs) to Stargas, and written final and reply arguments;

G. On October 29, 2020, the Silver Star Property Owners Association (SSPOA) registered as an intervener in the proceeding;

H. On May 3, 2021, the BCUC issued its Decision and Order G-133-21 on the Stargas Natural Gas Purchase Plan and Commodity Rate Application Effective November 1, 2020. In this decision, the BCUC approved, among other things, an increase to the commodity rate charged to Stargas customers from $3.98 per GJ to $5.82 per GJ, effective November 1, 2020. The BCUC directed Stargas to recover, as a one-time charge to ratepayers, the difference between the interim commodity rate of $3.98 per GJ and permanent commodity rate of $5.82 per GJ retroactive to November 1, 2020, with interest at the average prime rate of Stargas' principal bank for 2020, in the billing period immediately following the issuance of the decision; and

I. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the reasons stated in the Decision issued concurrently with this order, the BCUC orders as follows:

1. Stargas is approved to charge a delivery rate of $4.21 per GJ to all ratepayers on a permanent basis, effective November 1, 2020, as set out in Table 8 of the Decision.

2. Stargas is directed to refund to ratepayers the difference between the interim rates and permanent delivery rates, with interest at the average prime rate of Stargas' principal bank for the most recent year, at the same time the difference between interim and permanent commodity rates is recovered from ratepayers pursuant to Order G-133-21.

3. Stargas' request to record the approved 2021 CMI regulatory costs in a regulatory account and to defer the recovery mechanism until a future application is denied. Stargas is directed to include $17,500 of forecast 2021 CMI regulatory costs in the 2021 Revenue Requirement and 2021 delivery rate, effective November 1, 2020, as set out in Table 8 of the Decision.

4. Stargas is approved to establish a 2021 Delivery Rate and Regulatory Account Application account to capture BCUC direct costs and other third-party costs related to the Application. This non-rate base regulatory account is approved to accrue interest based on Stargas' weighted average cost of capital, with the amortization period and determination of the recovery mechanism to be determined in Stargas' next revenue requirements application.

5. Stargas' request to establish an Interest Deficit regulatory account to recover the proposed 'interest deficit' amount for the period June 1, 2017 to October 31, 2020 is denied.

6. Stargas' request to establish an Undistributed Return on Equity (ROE) regulatory account to recover the proposed 'undistributed ROE' amount for the period June 1, 2017 to October 31, 2020 is denied.

7. With respect to the previously approved 2018 Incident Shortfall regulatory account:
    a. Stargas is approved to record costs related to the incident in the amount of $16,687 in this regulatory account; and
    b. Stargas is directed to include the full amortization of the regulatory account in the 2021 Revenue Requirement and 2021 delivery rate, effective November 1, 2020, as set out in Table 8 of the Decision.
8. Stargas is directed to record a credit of $31,000 in the previously directed New Services Installations regulatory account, and to amortize the full balance in the 2021 Revenue Requirement and 2021 delivery rate, effective November 1, 2020, as set out in Table 8 of the Decision.
9. Stargas is directed to file with the BCUC, within 10 business days of the issuance of this order, amended Tariff pages and finalized financial schedules for the 2021 Revenue Requirement and 2021 delivery rate in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of May 2021.

BY ORDER

Original signed by:

C. M. Brewer
Commissioner

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

and

Stargas Utilities Ltd.
Delivery Rate and Regulatory Account Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated October 26, 2020 – Appointing the Panel for the review of Stargas Delivery Rate and Regulatory Account Application dated September 22, 2020
A-2	Letter dated October 28, 2020 – BCUC issuing Order G-272-20 with Reasons for Decision establishing a regulatory timetable for the review of the Application
A-3	Letter dated November 26, 2020 – BCUC Information Request No. 1 to Stargas
A-4	**CONFIDENTIAL –** Letter dated November 26, 2020 – BCUC Confidential Information Request No. 1 to Stargas
A-5	Letter dated December 11, 2020 – BCUC Order G-328-20 amending the regulatory timetable
A-6	Letter dated January 12, 2021 – BCUC Request to Stargas to resubmit the documents
A-7	Letter dated January 14, 2021 – BCUC response to SSPOA submission
A-8	Letter dated January 21, 2021 – BCUC Order G-22-21 establishing a further regulatory timetable
A-9	Letter dated February 9, 2021 – BCUC Information Request No. 2 to Stargas
APPLICANT DOCUMENTS	
B-1	**STARGAS UTILITIES LTD. (STARGAS)** – Delivery Rate and Regulatory Account Application dated September 22, 2020 – Redacted
B-1-1	Letter dated January 19, 2021 – Stargas submitting unredacted version of Delivery Rate and Regulatory Account Application dated September 22, 2020
B-2	Letter dated October 30, 2020 – Stargas Submitting Supplementary Information
B-3	Letter dated October 30, 2020 – Stargas submitting tariff page

B-4	Letter dated January 19, 2021 – Stargas submitting unredacted version of request of further deferment to file Information Request responses dated December 9, 2020
B-4-1	**REDACTED** – Letter dated December 9, 2020 – Stargas redacted request of further deferment to file Information Request responses
B-5	Letter dated December 11, 2020 – Stargas request of further deferment to file Information Request No. 1 responses
B-5-1	Letter dated January 19, 2021 – Stargas submitting unredacted version of request of further deferment to file Information Request No. 1 responses dated December 11, 2020
B-6	Letter dated December 16, 2020 – Stargas responses BCUC Information Request No. 1
B-7	Letter dated December 16, 2020 – Stargas responses SSPOA Information Request No. 1
B-8	Letter dated January 19, 2021 – Stargas submitting unredacted version of responses to BCUC Confidential Information Request No. 1 dated December 18, 2020
B-9	Letter dated January 19, 2021 – Stargas submitting response to BCUC request in Exhibit A-6
B-10	Letter dated February 15, 2021 – Stargas submitting response to BCUC Information Request No. 2
B-11	Letter dated February 17, 2021 – Stargas submitting response to SSPOA Information Request No. 2

INTERVENER DOCUMENTS

C1-1	**SILVER STAR PROPERTY OWNERS ASSOCIATION (SSPOA)** – Letter dated October 29, 2020 – Request for Intervener Status by Michael Waberski
C1-2	Letter dated November 17, 2020 – SSPOA submitting Information Request No. 1 to Stargas
C1-3	Letter dated January 12, 2021 – SSPOA submitting procedure clarification
C1-4	Letter dated February 8, 2021 – SSPOA submitting Information Request No. 2 to Stargas

INTERESTED PARTY DOCUMENTS

D-1	**FORTISBC ENERGY INC. (FEI)** – Submission dated January 8, 2021 request for Interested Party status by Brandi Paulson