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September 28, 2020

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599120

Annual Review for 2020 and 2021 Delivery Rates (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On August 12, 2020, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-209-20 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-2, page 5

> The delivery rates for 2020 flowing from the revenue requirement components set out in the Application result in a 3.27 percent increase from 2019 delivery rates; however, FEI is proposing to make permanent the existing interim delivery rates for 2020, effective January 1, 2020, and to capture the revenue deficiency greater than 2 percent in the existing 2017 & 2018 Revenue Surplus deferral account.
>
> The proposed delivery rates for 2021, after drawing down the balance of the 2017 & 2018 Revenue Surplus deferral account, result in a 6.59 percent increase from 2020 delivery rates.

1.1 Are the delivery rates referenced for the calendar year, or the fiscal years?

1.1.1 If for the fiscal years, please identify when the fiscal year ends.

Response:

FEI's fiscal year matches the calendar year. Therefore, the delivery rates referenced are for both the calendar and FEI's fiscal year.

2. Reference: Exhibit B-2, page 12

Table 2-2: Average Customer (AC) Growth Factor Calculation[11]

Line No.		2020	2021	Reference
1	Average Customer Forecast - Prior Year	1,031,862	1,043,259	
2	Average Customer Forecast - Test Year	1,043,259	1,053,292	Schedule 19, Row 30
3	Average Customer Change	11,397	10,033	Line 2 - Line 1
4	Customer Growth Factor Multiplier	75%	75%	
5	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 3 x Line 4
6				
7	*Average Customer Continuity for Rate Setting Purposes*			
8	Average Customer Forecast - Prior Year	1,031,862	1,040,410	Prior Year Line 10
9	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 5
10	Average Customer Forecast - Rate Setting Purposes	1,040,410	1,047,935	Line 8 + Line 9

2.1 Please identify on what dates the Average Customer Forecast – Prior Year and the Average Customer Forecast – Test Year were developed for 2020 and 2021, i.e. what is the date of the data sets used to derive the Forecasts?

Response:

For the 2020 column, 2019 is the Prior Year and 2020 is the Test Year. For the 2021 column, 2020 is the Prior Year and 2021 is the Test Year.

For 2019, the average customer forecast is the 12-month average of the January to December 2019 actual customer count.

For 2020, the average customer forecast was developed using the 12-month average of the January 2020 to June 2020 actual customer count and the July 2020 to December 2020 projected customer count.

For 2021, the average customer forecast was developed using the 12-month average of the January 2021 to December 2021 forecast customer count.

FEI's customer forecasting method can be found in Appendix A3 of the Application and was used to derive the customer counts for each of 2020 and 2021, except for January to June 2020, which is FEI's actual customer counts for those months.

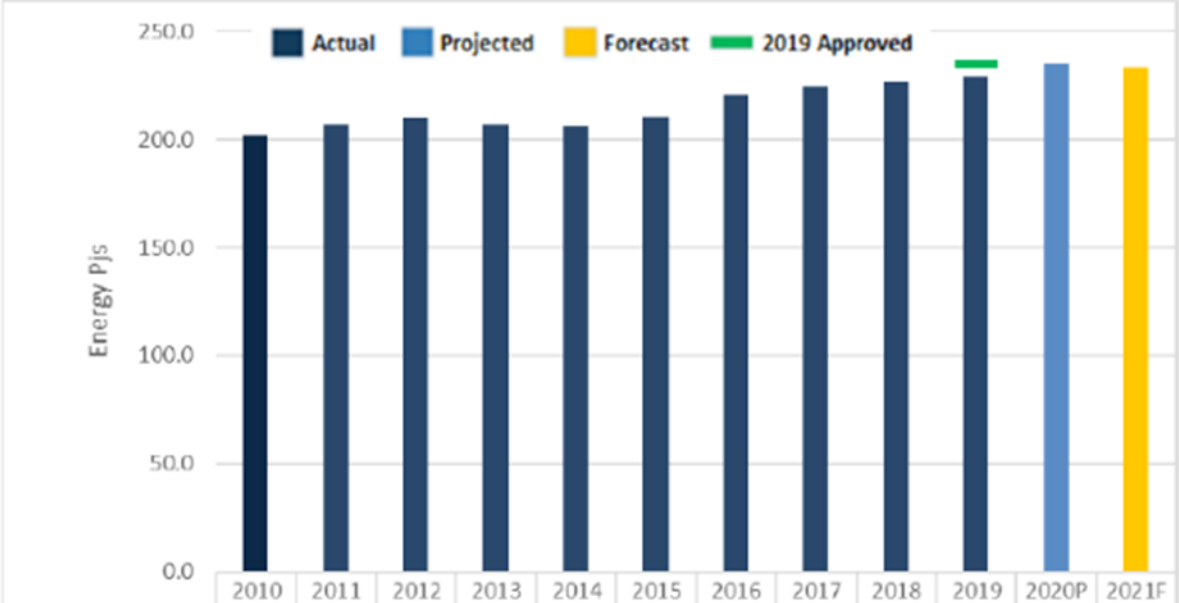
3. Reference: Exhibit B-2, page 13 and page 15

FEI is forecasting minimal change in consumption in the 2020 Projected (2020P) forecast (which includes actuals to June 30, 2020) compared to the 2019 Approved forecast. The total 2020P normalized[12] demand is projected to be approximately 235.4 PJs, which is nearly equal to the 2019 Approved demand. Based on the 2019 Approved rates for each customer class, FEI's 2020 Projected revenue forecast is $1,299 million and FEI's 2020 gross margin forecast is $849 million.

FEI is forecasting a decrease in consumption in the 2021 Forecast (2021F) compared to the 2020 Projected forecast. The 2021F normalized load is forecast to be approximately 233.6 PJs, which is a 1.8 PJ decrease compared to 2020 Projected forecast. The decrease in 2021F is due to decreased loads in the residential and industrial classes. Based on the 2020 Approved Interim rates for each customer class, FEI's 2021 revenue forecast is $1,391 million and FEI's 2021 gross margin forecast is $875 million.

FEI has provided further information supporting its demand forecast in Appendix A of the Application.

Figure 3-1: Total Energy Demand in PJs



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Total Demand	201.9	206.7	209.9	206.6	206.5	210.6	220.6	225.0	227.3	229.0	235.4	233.6
2019 Approved										235.4		

3.1 Please provide an explanation as to why the Total demand for 2019 is 6.5 PJs below the Approved Demand for 2019. What factors contributed to the difference?

Response:

FEI notes that the variance was 6.4 PJs or 2.7 percent, and not 6.5 PJs.

The 6.4 PJ variance was due to the following:

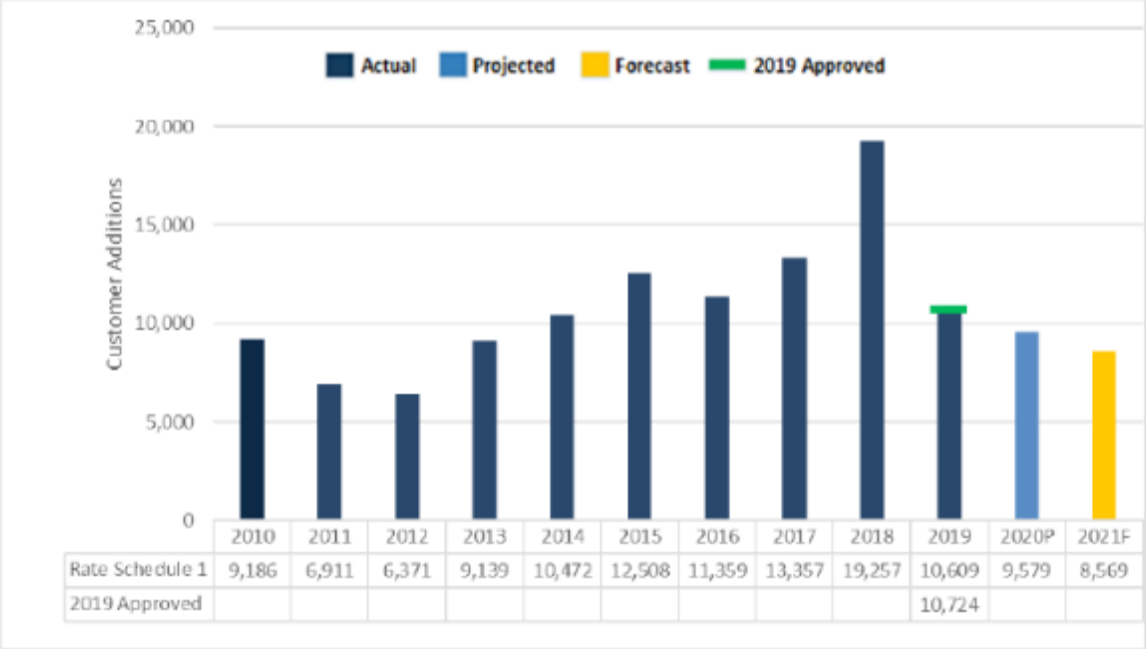
- The actual residential customer count was 0.6 percent higher than forecast, but residential UPC was 5.6 percent below forecast. As a result, residential demand was 4.9 percent below forecast.
- The commercial customer count was forecast to be 96,570 and the actual total was within 0.04 percent, at 96,530. However, all commercial use rates were lower than forecast, so the commercial demand was 5.9 percent below forecast.
- Industrial demand was 1 percent higher than forecast.

Together, these rate groups combined to produce the result in Figure 3-1.

Over the past ten years, this was the fourth lowest aggregate demand variance recorded.

4. Reference: Exhibit B-2, pages 16 and 17

Figure 3-2: Residential Net Customer Additions



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 1	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	9,579	8,569
2019 Approved										10,724		

3.3.1.1 Residential Customer Additions

Consistent with past practice, FEI uses the Conference Board of Canada (CBOC) housing starts forecast as a proxy for residential net customer additions. The CBOC data used for the forecast, in Appendix A3, was issued prior to the start of the pandemic and, at the time of this filing, the CBOC had not issued an updated single or multi-family forecast. The 2021 forecast of 8,569[14] additions reflects a lower CBOC housing starts forecast for BC than experienced in 2019 or projected for 2020. In deriving the 2020 projection, the first six months of the forecast of customer additions were replaced by actual values. As shown in Figure 3-2, residential customer additions are forecast to decrease by 1,145 in 2020P compared to 2019 Approved and decrease by 1,010 additions in 2021F compared to 2020P.

4.1 Please explain why customer additions were so significant in 2018?

Response:

FEI cannot definitively explain the cause of the increase in 2018 or the cause of the decline since 2018, as there are many compounding and offsetting factors that affect net customer additions. Net customer additions comprise various activities such as new or gross customer attachments, move-ins, move-outs and vacancies (disconnects and non-disconnects). Gross additions occur when new customers attach to the natural gas system. As new housing stock is constructed, and customers in existing houses convert to using natural gas, net customers will

increase. If fewer disconnections occur, the increase in net customers will be greater. An increase in new customer connections can be offset by a higher number of customers disconnecting gas service; for example, if a home is torn down. On a customer base of more than a million customers, small variations in these factors can swing net customer additions.

With respect to gross customer additions, attachments were strong in 2018 largely due to a surge in housing construction and an increase in housing densification (e.g., more townhome dwellings). However, for 2019 and beyond, gross customer additions declined slightly as the housing construction market softened, which can be attributed to policy and regulation changes that affect the purchase or ownership of a home such as tightening mortgage rules, the foreign buyer's tax and the speculation tax. In addition, municipal regulations on greenhouse gas emissions are having an impact on the percentage of new construction houses that use natural gas. For 2020 and beyond, the CBOC forecast for housing starts was issued prior to the COVID-19 pandemic and it does not reflect any impact of the pandemic on new housing construction on future years. FEI expects that net additions will continue to be influenced by many factors that may have affected additions variances in the past, such as customer behaviour, economic activity, DSM, government policies (such as environmental policy), new technology, housing formations, etc. The current methods FEI utilizes fully account for all these intrinsic factors and together result in long-term forecast performance that is significantly better than the industry average.

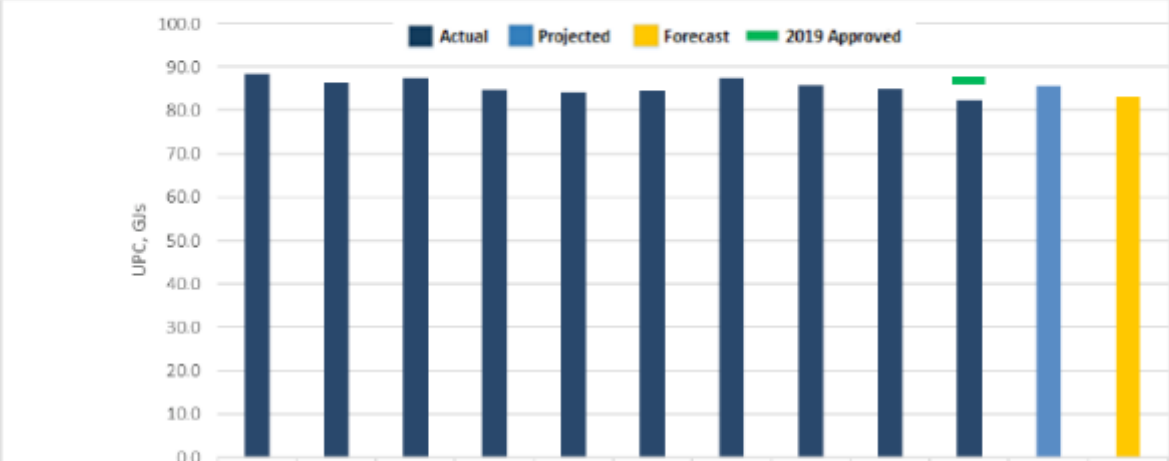
4.2 What factors are causing customer additions to decline since 2018?

Response:

Please refer to the response to CEC IR1 4.1.

5. Reference: Exhibit B-2, page 17

Figure 3-3: Rate Schedule 1 UPC



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Rate Schedule 1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	85.7	83.1
2019 Approved										87.0		

5.1 Is the UPC weather adjusted? Please explain the reason why or why not.

Response:

Yes, the residential UPC is weather adjusted. As described in Section 2.4 of Appendix A3, Rate Schedule 1 demand is weather normalized because residential demand is highly correlated with temperature.

5.2 Please provide the date from the 2020P was derived.

Response:

As stated in Section 3.3.1.2 of the Application, the Projected Year is forecast using the most recent 10 years of historical weather-normalized UPC, which for 2020P would include years up to 2019. The January through June forecast values were then replaced with January through June Actual 2020 values. See Section 5 of Appendix A3 of the Application for FEI's UPC forecast method.

5.3 The Actual UPC appears to be slowly declining over time. Please provide any explanation FEI has for this circumstance.

Response:

Please refer to the response to BCUC IR1 7.3.

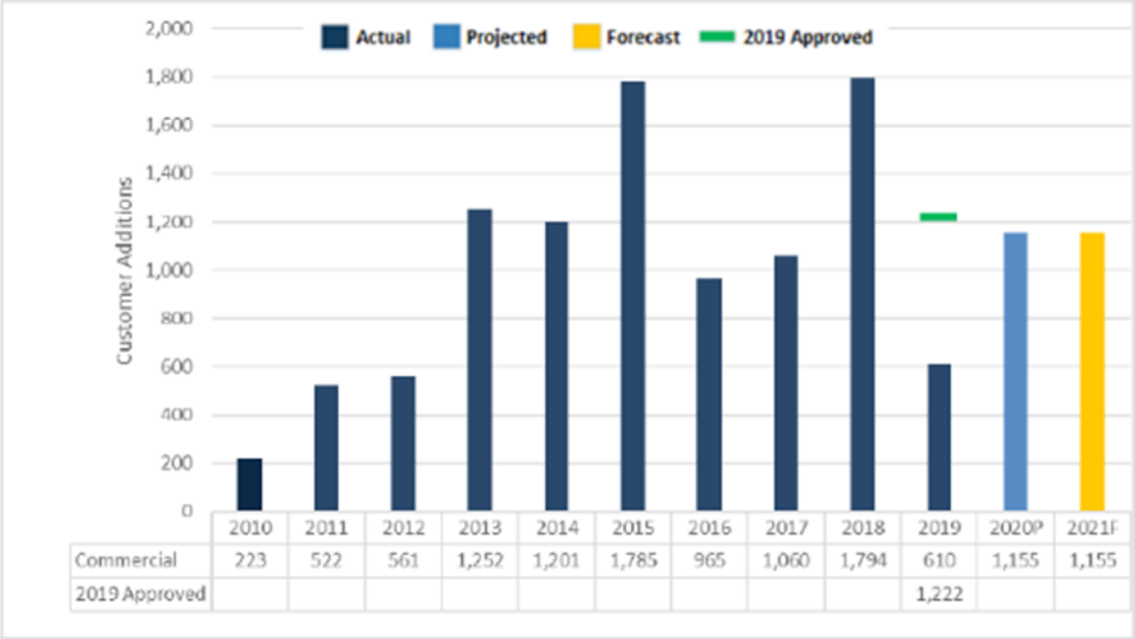
6. Reference: Exhibit B-2, page 18-19

3.3.2.1 Commercial Customers

The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2017 to 2019). As there was a relatively large migration of Rate Schedule 23 transportation customers to bundled service under Rate Schedule 3 over the past years, these two rate classes were forecast together as "large commercial" and the total allocated to the two rate classes proportional to the current composition. For 2020, the first six months of the forecast were replaced by actual values.

As shown in Figure 3-5 below, commercial customer additions are forecast to decrease by 67[15] customers in 2020P compared to 2019 Approved and remain flat in 2021F.

Figure 3-5: Commercial Net Customers Additions



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Commercial	223	522	561	1,252	1,201	1,785	965	1,060	1,794	610	1,155	1,155
2019 Approved										1,222		

6.1 Please explain why there was a migration of RS 23 customers to bundled service under RS 3 over the past years.

Response:

The migration of customers between transportation service and bundled service is typically driven by economics, i.e. the cost of gas, and the customer's level of comfort with potential market volatility. As discussed below, FEI believes the migration of RS 23 customers to bundled service over the past years has been driven by FEI's cost of gas rate being lower and more stable than prices at the Huntingdon/Sumas market.

Many of the Lower Mainland transportation service customers do not contract pipeline capacity, and therefore rely on the demand hub at Huntingdon/Sumas. The customer movement to the bundled service has been occurring since 2016, which corresponded with FEI's gas cost rate becoming lower than the Huntingdon/Sumas priced product. The largest customer movement to the bundled service was following the rupture on the T-South pipeline system in the 2018/19 winter which caused volatility in the Huntingdon/Sumas market. The average Huntingdon/Sumas daily price for the entire 2018/19 winter was approximately $15 Cdn/GJ, which was $12 Cdn/GJ higher than FEI's cost of gas. Throughout the 2018/19 winter, FEI received calls from transportation service customers expressing their concern about the impact that the cost of gas at Huntingdon/Sumas was having on their business. Approximately 43 percent of RS 23 customers switched to bundled service as of November 1, 2019.

6.2 Why does FEI use an average of 3 years for commercial net customer additions instead of using other external information such as forecasts for the economy? Please explain.

Response:

As reported in Section 5.1 of Appendix A4 of the Annual Review for 2017 Delivery Rates, FEI tested 11 econometric forecasts prepared by the Conference Board of Canada (CBOC) for British Columbia for their suitability to forecast commercial customer additions. All forecasts tested failed the T-Test[1] at the 95 percent confidence limit for commercial customer additions. FEI services over 95,000 commercial customers operating in 179 industry groups and believes that this broad mix of industry groups is responsible for the poor correlation to broad economic forecasts.

In Appendix B2 of the 2020-2024 Multi-Year Rate Plan Application, FEI reported on the completion of its review of alternate commercial customer additions methods. Based on the results, FEI concluded that the existing method that uses three years of commercial net customer additions provided the best performance.

6.3 Why does FEI believe that 3 years is the appropriate average instead of any other term such as 5 years?

[1] Failing the T-Test implies that the data did not provide sufficient evidence to conclude that a relationship exists.

Response:

FEI believes that a three-year average provides a reasonable mix of current trends with enough data to smooth out some natural fluctuations and "noise".

In Appendix B2 of the 2020-2024 Multi-Year Rate Plan Application, FEI reported on the completion of its review of alternate commercial customer additions methods. Based on the results FEI concluded that the existing method provided the best performance. The ETS method, which makes use of all available data, was shown to perform more poorly than the existing method.

The 2019 forecast of customer additions (1,222) was developed by considering customer additions in 2016, 2017 and 2018. As shown in the following table, switching to a five-year average (by including 2013 and 2014) produces a similar result (1,227).

Customer Additions	3 Yr Average 2015-2017	5 Yr Average 2013-2017
RS2	1,116	1,170
RS3	91	44
RS23	16	13
Total	**1,222**	**1,227**

6.4 Is the methodology for calculating net customer additions for any of the rate classes established in the MRP, or does FEI have discretion in how to create its forecasts? Please explain.

Response:

While FEI has discretion to adjust forecast methods as needed to adapt to data anomalies, it is important to maintain as much consistency as possible with forecast methods. If methods are constantly changing, it becomes unclear if future variances are a result of changes in market conditions or customer behaviour, or if the variances are resulting from method changes. If the methods are consistent, we can more readily attribute changes in demand to customer behaviour.

That said, in cases like Rate Schedules 3 and 23 where an unmodified application of the existing method would have resulted in an unrealistic forecast, FEI does believe it is appropriate to make adjustments while remaining as true to the original method as possible.

7. Reference: Exhibit B-2, page 22 and page 23 and Appendix A3 page 17

3.3.3 Industrial Demand

The 2020P demand for industrial customers was developed using 2020 actual demand from January through June and 2019 actual demand for July through December.

The 2021F demand for industrial customers was forecast using the Industrial Survey.

For the 2021 Forecast, customers responded to the survey in June and July of 2020. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast, particularly from Rate Schedule 22 customers. The survey needed to be completed by July 6, 2020 to allow sufficient time for internal review of the results, loading of data in FEI's Forecasting Information System (FIS), preparing the forecast and drafting the Application. Since the survey requires approximately five weeks to complete, it was launched on June 5, 2020.

As shown in Table 3-1 below, the response rate achieved in 2020 was 46.7 percent of industrial customers, representing approximately 89.3 percent of industrial volumes. There was no reply from 44.5 percent of industrial customers, who received the survey and three reminder notifications; this group represents only 9.5 percent of the industrial demand. Surveys could not be delivered to 8.8 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 1.2 percent of the total industrial load.

Table 3-1: Industrial Survey Response Rates

2020 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	46.7%	89.3%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	44.5%	9.5%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	8.8%	1.2%
Total		100.0%	100.0%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 11 percent of the total industrial demand) was set to equal 2019 Actual consumption.

7.5 NON RESPONDERS AND THE REMINDER EMAIL

Once the survey is started, responses start coming in within the hour. A steady response rate normally continues for several days, but eventually slows. The survey system tracks the status of each survey and at all times FEI knows the response rate. Until the target response rate is reached, FEI sends out a weekly reminder email to those customers that have not yet responded. The reminder email contains the same link to the survey. The reminder step enhances the response rate of the survey. A sample is shown below:

7.1 Did FEI undertake to call or otherwise make personal contact beyond reminder emails with the over 50% of customers that did not reply? Please explain.

Response:

Yes.

Consistent with past surveys, after the second reminder email was sent out, there were still a number of customers that had not responded to the survey. Key account managers were provided a list of non-responding customers and attempted to personally connect with these customers. Not all customers are contacted, and the emphasis is to connect with larger volume customers. FEI does not have statistics to show what percentage of the personally contacted customers eventually responded. The survey database system was not designed to track such interactions.

To permit time to collect and analyze the survey results prior to filing, the survey was closed on July 6th. At that time, 46.7 percent of customers, representing 89.3 percent of the industrial demand, had responded.

7.2 Please provide the historical response rates to the industrial survey over the last 5 years.

Response:

Please refer to the response to BCUC IR1 8.1.

7.3 If the response rate is lower than usual, please provide FEI's best assessment of why that has occurred.

Response:

Please refer to the response to BCUC IR1 8.1.

7.4 Please confirm or otherwise explain that COVID-19 may well have had negative impacts on the financial well-being of several of FEI's industrial customers.

Response:

Confirmed, COVID-19 may have had negative impacts on the financial well-being of several of FEI's industrial customers, and different industry segments were impacted in different ways. However, negative financial impacts may not correlate with changes in natural gas demand.

7.5 Recognizing that FEI anticipates an increase in demand for 2020, does FEI expect that industrial demand has been or will be significantly impacted by COVID-19? For instance, is it likely that demand would have been higher in the absence of COVID-19? Please explain why or why not.

7.5.1 If yes, please elaborate on how the demand may be impacted and provide quantification if available.

Response:

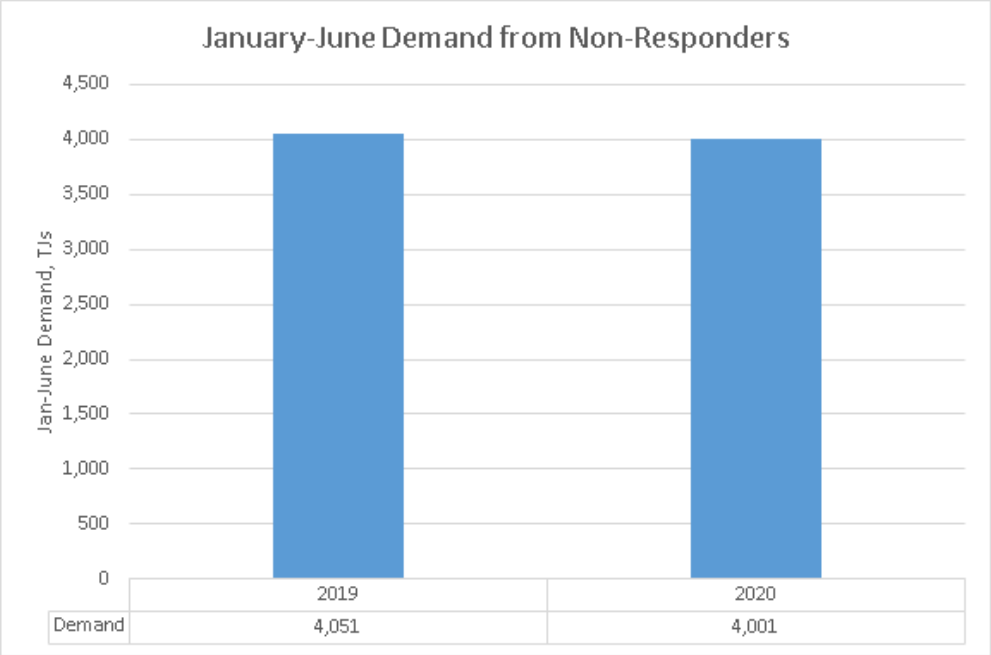
As indicated in the response to CEC IR1 7.4, while COVID-19 may well have had negative impacts on the financial well-being of several of FEI's industrial customers, negative financial impacts may not correlate with changes in natural gas demand. Different industry groups are impacted in different ways by the pandemic and even different customers within an industry group can be impacted differently. FEI is unable to quantify the impact of COVID-19 on industrial demand, and does not wish to speculate about what the natural gas demand would be in the absence of COVID-19.

7.6 For those customers that did not complete the survey, does FEI have any indication that the companies are still operating at the same levels as they were

during 2019? Or is it possible that those companies have been wound down or operating at a much lower level than historically? Please explain.

Response:

The following figure shows the 2019 and 2020 January-June demand for the customers that did not respond to the Annual Industrial Survey.



Demand for this group of customers in 2020 was 99 percent of the 2019 demand. The decline is 50 TJs, year over year.

FEI believes it is reasonable to assume that, as a group, these customers are operating at the same levels as they were during 2019.

7.6.1 If it is possible that some of the companies have wound down or are operating at a lower level during COVID-19, why did FEI set the demand equal to 2019 Actual consumption?

Response:

Many industry segments are represented by the group of customers that chose not to respond to the survey. FEI believes that different industry segments are impacted by the pandemic in different ways. For some, demand may go down, but the largest segment of non-responding customers is strata corporations and it is conceivable that their post-COVID-19 demand may have gone up.

As described in the response to BCUC IR1 8.3, the majority of the smaller customers that do respond to the survey provided a forecast that was equal to their 2019 Actual Consumption. As a result, it is reasonable to also set the demand for similar sized non-responding customers to their 2019 Actual Consumption.

7.7 Please provide monthly actuals for industrial demand for the last 3 years and break out the demand for the customers replying to the survey and those not replying to the survey.

Response:

The requested information is provided in the table below.

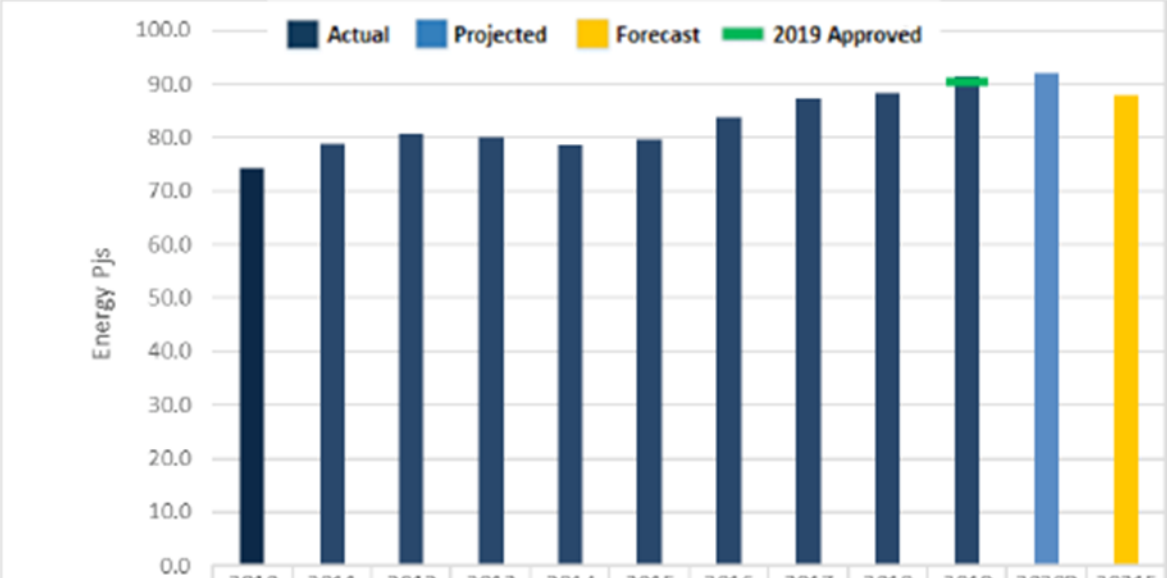
Industrial Demand, PJs*	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017													
Non-responder	0.9	0.8	0.8	0.6	0.5	0.4	0.4	0.4	0.4	0.6	0.8	0.9	7.7
Responder	6.4	5.4	5.7	5.0	4.6	4.0	3.7	3.8	3.9	4.9	5.4	5.8	58.6
2018													
Non-responder	1.1	1.0	1.0	0.8	0.6	0.6	0.5	0.5	0.6	0.8	0.9	1.0	9.3
Responder	5.8	5.7	5.7	4.9	4.4	4.3	4.0	4.2	4.5	4.5	4.8	5.1	58.0
2019													
Non-responder	1.0	1.0	0.9	0.7	0.6	0.5	0.5	0.5	0.6	0.9	1.0	1.0	9.0
Responder	5.9	5.9	5.5	5.2	4.7	4.3	4.3	4.2	4.3	5.4	5.7	5.9	61.2

* Excludes BCH Cogen and Joint Venture

8. Reference: Exhibit B-1, pages 23 and 24 and Appendix A3 page 20

As seen in Figure 3-11 below, the demand from the industrial rate schedules is forecast to increase by 1.3 PJ in 2020P compared to 2019 Approved and then decrease 4.1 PJs in 2021F comparted to 2020P.

Figure 3-10: Industrial Demand[18]



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Industrial	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	91.9	87.8
2019 Approved										90.6		

7.7 REVIEWING THE SURVEYS

Surveys from large volume customers in RS 22 and RS 27 are reviewed by the Forecast Manager and two Commercial and Industrial Energy Solutions Managers. The Commercial and Industrial Energy Solutions Managers are well informed about the issues with each individual customer and are able to rationalize the survey received from the customer. Where surveys are contrary to the information the Commercial and Industrial Energy Solutions Managers have, a follow up call is made and the survey is adjusted if required.

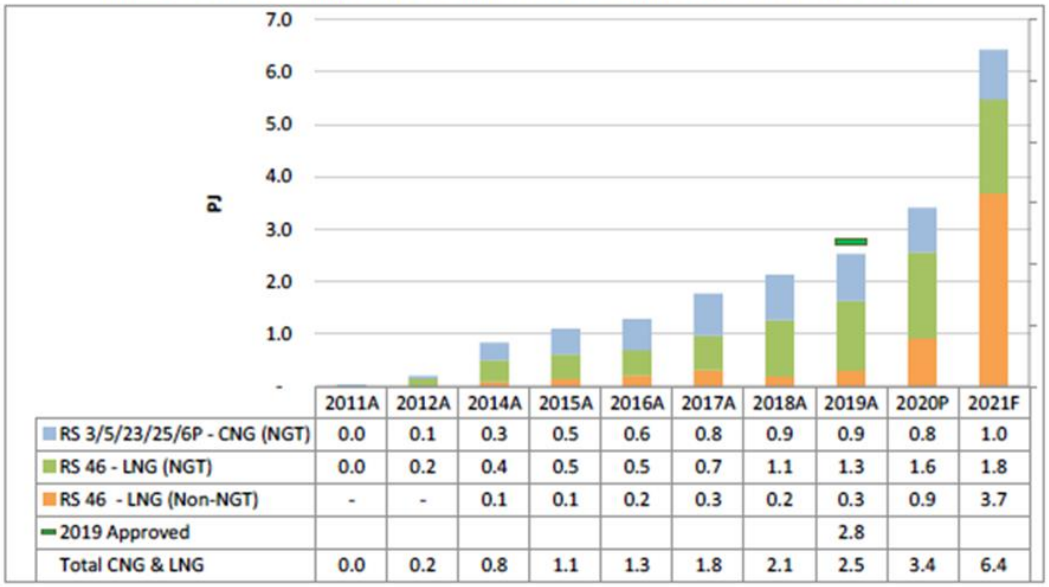
8.1 What is FEI's understanding of the reasons for the expected reduction in Industrial demand in 2021? Are there trends that can be seen amongst customers? Please explain.

Response:

The reduction is primarily attributable to a handful of industrial customer sites in the Pulp & Paper, Wood Products and Cannabis sectors. Three customer sites closed down and one other customer had a temporary significant increase in natural gas consumption, but has now returned to normal operation. The final customer has forecast an approximate 25 percent reduction in gas use, but this is consistent with historical consumption for that facility. FEI does not believe these specific incidents represent a trend, but do support FEI's Industrial Survey method, as an econometric or other forecast method would not be able to identify these individual and significant changes.

9. Reference: Exhibit B-2, page 25

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[17]



	2011A	2012A	2014A	2015A	2016A	2017A	2018A	2019A	2020P	2021F
RS 3/5/23/25/6P - CNG (NGT)	0.0	0.1	0.3	0.5	0.6	0.8	0.9	0.9	0.8	1.0
RS 46 - LNG (NGT)	0.0	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.6	1.8
RS 46 - LNG (Non-NGT)	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.9	3.7
2019 Approved								2.8		
Total CNG & LNG	0.0	0.2	0.8	1.1	1.3	1.8	2.1	2.5	3.4	6.4

The 2020 Projected demand is approximately 0.9 PJ higher than the 2019 Actual demand of 2.5 PJs. Of this 0.9 PJ increase, approximately 0.3 PJ (or approximately 30.2 percent) is attributed to demand that serves NGT customers while the rest of the increase is attributed to non-NGT demand involving LNG exports (approximately 0.6 PJ or 69.8 percent).

For 2021, the CNG demand for NGT customers is forecasted to increase by approximately 0.11 PJ (approximately 13 percent) from the 2020 Projected level. This is primarily attributable to incremental load from existing customers and two new CNG stations to be in-service starting in mid-2020 with demand ramp up by 2021. The LNG demand for NGT customers is forecast to increase by approximately 0.14 PJ (approximately 9 percent) from the 2020 Projected level which is primarily attributed to increased volumes from BC Ferries and Seaspan due to two additional fleet vessels.

For non-NGT demand, FEI expects the 2021 Forecast will continue to increase as a result of expanded LNG exports. This is an approximately 2.7 PJ increase from the 2020 Projected level.

9.1 Please provide further evidence supporting the anticipated increase in demand in CNG for 2021 from existing customers.

Response:

Please refer to the response to BCUC IR1 9.1

9.2 Please provide further evidence supporting the load projection from two new CNG stations. Are the new CNG stations already in service? Please explain.

9.2.1 If not, please provide a discussion of when these service stations are expected to be in service.

9.2.2 If not, has FEI received correspondence from these customers with any revisions to their expected load? Please explain.

Response:

FEI has finished the construction and commissioning of Fresh Direct in March and London Drugs mid-September 2020 and they are both in service now.

9.3 Please provide further evidence supporting FEI's projected LNG demand for 2021. Have the additional fleet vessels come into service? Have BC Ferries or Seaspan provided any further indications as to their expected loads? Please explain.

Response:

Please refer to the responses to BCUC IR1 9.1 and 9.3.

10. Reference: Exhibit B-2, page 27 and page 31

3.5 *SUMMARY*

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, or – in the case of the ETS method – represent a method that has been demonstrated to be superior to past practice as reported previously to the BCUC. FEI's forecast provides a reasonable estimate of future natural gas demand for 2020 and 2021. Based on these methods, FEI is forecasting a minimal change in consumption in 2020P compared to 2019 Approved, followed by a decrease in consumption in 2021F of 1.8 PJs compared to 2020P. Based on the 2019 and 2020 approved rates for each customer class, FEI's 2020 and 2021 revenue forecast is $1,299 million and $1,391 million respectively.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing charge that is applied to FEI fuelling station customers, tanker rentals from LNG customers, and CNG and LNG fuelling stations (CNG & LNG Service Revenues) as shown in Table 5-2 below. Variances between forecast and actual NGT Overhead and Marketing Recoveries will affect ROE and will be subject to earnings sharing. Variances in the NGT Tanker Rental Revenue and CNG & LNG Service Revenues are treated as Flow-through with the variances being captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2020 and 2021 NGT Related Recoveries

NGT Related Recoveries, ($ millions)	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
NGT Overhead and Marketing Recovery	$ 0.325	$ 0.305	$ 0.284	$ 0.258
NGT Tanker Rental Revenue	0.680	0.582	0.569	0.774
CNG & LNG Service Revenues	3.373	3.059	2.939	2.666
Total NGT Related Recoveries	**$ 4.378**	**$ 3.946**	**$ 3.792**	**$ 3.698**

The following subsections discuss each of the NGT related recoveries.

10.1 Please provide an estimate of the revenue forecast if FEI's demand for 2021 were 5%, 10% or 15% lower than expected.

Response:

FEI interprets this question to be referring to the total demand, as the reference to Section 3.5 in the preamble suggests. For the impact to the revenue requirement due to the NGT specific demand (CNG and LNG), please refer to the response to BCUC IR1 10.1.

Please refer to Line 12 of the table below for the estimates of the 2021 revenue deficiency for each demand scenario (5 percent, 10 percent, and 15 percent lower than the 2021 forecast). Please also refer to Line 15 of the table below for the estimated delivery rate impact (compared to FEI's 2021 proposed delivery rates) under each demand scenario.

Line	Particular	Unit	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(8)
1	2021 Demand Forecast per Application (Non-bypass & RS 46 LNG)	TJ	200,469	200,469	200,469	200,469	Section 11 - 2021, Schedule 19, Line 17 + Line 23, Col 10
2	Change in Demand	%	0%	-5%	-10%	-15%	
3	Change in Demand	TJ	-	(10,023)	(20,047)	(30,070)	Line 1 x Line 2
4							
5	2021 Effective Margin per GJ @ Existing Rate	$/GJ	4.230	4.230	4.230	4.230	Section 11 - 2021, Schedule 19, Line 17, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	-	(42,402)	(84,803)	(127,205)	Line 3 x Line 5
7							
8	2021 Non-Bypass Margin @ Existing Rate	$000s	824,897	824,897	824,897	824,897	Section 11 - 2021, Schedule 19, Line 17, Col 3
9	Updated 2021 Non-Bypass Margin @ Existing Rate	$000s	824,897	782,495	740,093	697,692	Line 6 + Line 8
10	2020 Non-Bypass Margin @ Revised Rate (Revenue Requirement)	$000s	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Col 5
11							
12	**2021 Revenue Deficiency/(Surplus)**	**$000s**	**(54,389)**	**(96,791)**	**(139,192)**	**(181,594)**	Line 9 - Line 10
13	Delivery Rate Change @ Each Demand Scenario	%	-6.59%	-12.37%	-18.81%	-26.03%	Line 12 / Line 9
14							
15	**Delivery Rate Impact vs. 2021 Proposed Rates per Application**	**%**	**0.00%**	**5.78%**	**12.21%**	**19.43%**	Line 15 @ Each Demand Scenario - Column (3)

10.1.1 How would such circumstances impact customer rates? Please provide quantification.

Response:

Please refer to the response to CEC IR1 10.1.

10.1.2 If FEI's demand forecast for 2021 is found to be overly optimistic by 10% or more before the beginning of 2021, would it be appropriate for FEI to revise its rates? Please explain why or why not.

Response:

As discussed in the response to BCUC IR1 10.1, any variances (deficiency or surplus) between the forecast and actual delivery margin are captured in the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account for variances in Rate Schedule 1, 2, 3, and 23 use rates, or the Flow-through deferral account for all other demand variances. Through the amortization of these deferral accounts, the resulting revenue requirement impacts are returned to or recovered from non-bypass customers in the subsequent years. As such, non-bypass customers are kept whole for any demand forecast variances.

As shown in response to CEC IR1 10.1, a demand forecast that is 10 percent or more below what has been proposed would result in a rate change in excess of 10 percent or what is commonly considered rate shock. In such a scenario, FEI would propose a deferral account to smooth in the rate increase, and the same result can be achieved through the existing RSAM and flow-through mechanisms.

11. Reference: Exhibit B-2, pages 34 and 35

5.3 SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE

The SCP Third Party Revenue includes the items shown in the table below.

Table 5-6: 2019, 2020 and 2021 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ millions)				
	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
NW Natural	$ 5.763	$ 5.763	$ 4.154	$ -
MCRA	3.600	3.600	5.220	13.284
Net Other Mitigation - West to East Capacity	7.709	7.709	1.503	0.769
Total SCP Revenue	**$ 17.072**	**$ 17.072**	**$ 10.877**	**$ 14.053**

The components of the SCP Third Party Revenues shown in Table 5-6 are discussed separately below. Any variance from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

5.3.2 Midstream Cost Reconciliation Account (MCRA)

As shown in Table 5-6 above, 2019 Approved and 2019 Actual amounts include a $3.6 million per year credit in Other Revenue from the MCRA, which increases to $5.22 million in 2020 and $13.284 million in 2021. The 2019 amounts reflect the 58.5 MMcfd of SCP east to west capacity that FEI held as part of its midstream portfolio during that year. The increases in 2020 and 2021 are due to FEI's contract with NW Natural expiring November 1, 2020, and FEI taking back this capacity and holding it in its midstream portfolio, as explained in Section 5.3.1 above.

As the contract with NW Natural will continue until October 31, 2020, FEI seeks BCUC approval to continue debiting the MCRA and crediting Other Revenue in the amount of $300 thousand per month for the period of January 1, 2020 to October 31, 2020, during which FEI will continue to hold 58.5 MMcfd of SCP east to west capacity in its midstream portfolio.

Effective November 1, 2020, at which time the NW Natural contract will expire, FEI seeks BCUC approval for the debiting of the MCRA and crediting Other Revenue for the 105 MMcfd of SCP east to west capacity based on the cost of service valuation of $346.617 per MMcfd (equivalent to approximately $0.3059/GJ per day) as set out in Table 5-7 below.

11.1 Please confirm that the $300 thousand per month to continue being debited is for 10 months is the same as the $3.6 million debited from MCRA, which is annualized.

Response:

Confirmed.

11.2 Please explain why the reduction in NW Natural for Projected 2020 is $1.609 million below the Actual and Approved while the increase in the MCRA for Projected 2020 is only 1.22 million.

Response:

To clarify, the revenue associated with the east to west capacity on SCP, which is comprised of the NW Natural and MCRA lines from Table 5-6, is $9.363[2] million for Approved 2019 and Actual 2019, compared to $9.374[3] million for Projected 2020. Also, the MCRA Projected 2020 is $1.62[4] million higher than the Approved 2019 and Actual 2019 amounts, not $1.22 million as indicated in the question. Therefore, the total difference between Projected 2020 and the Approved / Actual 2019 for east to west capacity on SCP is $0.011[5] million.

The primary driver of the decrease in the NW Natural Projected 2020 revenue is that the NW Natural contract expires October 31, 2020, meaning that only ten months of revenues are recognized in the 2020 projection. Additionally, the NW Natural revenues are forecast and recorded net of the costs for the Enbridge Westcoast Energy Inc. (WEI) tolls related to the Kingsvale South transportation embedded in the NW Natural contract. The WEI Kingsvale South transportation tolls are subject to change.

[2] 5.763 + 3.600.
[3] 4.154 + 5.220.
[4] 5.220 – 3.600.
[5] 9.374 – 9.363.

12. Reference: Exhibit B-2, page 40

> **6.2 *FORMULA O&M EXPENSE***
>
> Base O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and 75 percent of the forecast growth in average customers. As calculated in Section 2, the 2020 and 2021 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 2.290 percent in 2020 and 3.358 percent in 2021.

12.1 Please provide the words relating to the UCOM acronym.

Response:

UCOM is FEI's acronym for Unit Cost O&M as set out in its MRP Application. It is equivalent to the O&M per customer.

13. Reference: Exhibit B-2, page 40

Table 6-2 below shows the calculation of the 2020 and 2021 Formula O&M.

Table 6-2: Calculation of 2020 and 2021 Formula O&M

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	246	252	G-165-20 FEI MRP Decision
2	I-Factor	2.290%	3.358%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	252	260	
4	Average Customer Forecast - Rate Setting Purposes	1,040,410	1,047,935	Section 2, Table 2-2
5	Inflation Indexed O&M	261.798	272.547	Line 3 x Line 4

13.1 Please confirm that the Average Customer Forecast for Rate Setting purposes is trued up to actuals at some point in the MRP Process, and explain where this occurs.

Response:

Confirmed. FEI will true-up the Average Customer Forecast and its impact on O&M funding each year during the term of the MRP. For example, the true up for the 2021 forecast will occur once 2021 actuals are available (in 2022 for setting 2023 rates). Each year, there is a two-year time lag between the forecast and the true-up, such that the final true-up for the 2024 forecast will be calculated in 2025 for 2026 rates.

14. Reference: Exhibit B-2, page 40 and 41

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 115), the BCUC directed FEI to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: integrity management; maintaining system infrastructure; operations, compliance and safety; cyber security; data analytics; gas control; CEPA participation; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category in 2019 dollars, escalated by the annual formula factors to arrive at the Formula O&M amounts, and the forecast amounts for 2020.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending

System Operations, Integrity and Security		2020 Formula O&M[1]	Forecast 2020 O&M	2020 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
		$ millions			
Integrity Management	$ 1.350	$ 1.381	$ 1.381	$ -	$ -
Maintaining System Infrastructure	$ 0.700	$ 0.716	$ 0.716	$ -	$ -
Operations, Compliance and Safety	$ 0.600	$ 0.614	$ 0.614	$ -	$ -
Cyber Security	$ 0.508	$ 0.520	$ 0.520	$ -	$ -
Data Analytics	$ 0.300	$ 0.307	$ 0.307	$ -	$ -
Gas Control	$ 0.650	$ 0.665	$ 0.665	$ -	$ -
CEPA Participation	$ 0.700	$ 0.716	$ 0.716	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -
Total	$ 4.808	$ 4.918	$ 4.918	$ -	$ -

Notes:
(1) 2020 Formula O&M is the incremental funding with Net Inflation factor applied (2.290%)
(2) Cumulative Forecast/Actual variance is the same as the 2020 (first year of MRP) Forecast/Actual variance.

14.1 Please label the 2nd column.

Response:

The title of the second column in Table 6-3 should be “Approved Base O&M”. The column contains the amounts for the System Operations, Integrity and Security New/Incremental O&M funding requests approved by the BCUC as part of the Base O&M for the MRP.

15. Reference: Exhibit B-2, page 41

> At the time of preparing this Application, FEI has critical initiatives underway and is in the process of finalizing its plans to implement further activities. As shown in the table above, FEI is forecasting to spend all of the incremental funding approved. For 2020, given that the MRP Decision was issued part way through the year, there will likely be a variance between the actual expenditures in 2020 and the amounts calculated using the formula escalators. Over the term of the MRP, FEI anticipates that the total new/incremental spending in the combined categories of System Operations, Integrity and Security required will be relatively close to the cumulative approved formula amounts, although there will continue to be variations from year to year.
>
> In the MRP Decision, the BCUC also directed FEI to describe how it is prioritizing its new/incremental funding approved for System Operations, Integrity and Security.

15.1 Is the New/Incremental funding included in Formula O&M, or is it provided in addition to Formula O&M?

Response:

The total New/Incremental O&M funding of $4.808 million for System Operations, Integrity and Security was approved as part of the Base O&M by the BCUC in the MRP Decision[6] and is therefore included as part of total Formula O&M.

15.2 Please elaborate on why the issuance of the Decision will impact the actual expenditures. Why can FEI not 'catch up' the spending over the last half of the year.

Response:

As mentioned in the Application, FEI is undertaking efforts to complete the activities and spending as planned. However, given that BCUC approval for the incremental funding was not provided until mid-2020, there may be variances for some of the incremental funding, particularly where recruitment for additional labour resources is required (i.e., additional gas controller positions). Variances due to labour vacancies and the general timing of expenditures are expected to occur from time to time.

Over the term of the MRP, FEI anticipates that the total new/incremental spending in the combined categories of System Operations, Integrity and Security will be relatively close to the cumulative approved formula amounts, although there will be variations from year to year.

[6] FEI MRP Decision, page 114.

15.3 Please rationalize FEI's statement that there will likely be variances with FEI's Forecast 2020 O&M being the same as the Formula O&M.

Response:

FEI's forecast that 2020 O&M will be the same as 2020 Formula O&M for System Operations, Integrity and Security incremental funding is reasonable as it reflects FEI's plan and efforts to spend all the incremental funding approved. While a variance of some kind is likely for the reasons explained in CEC IR1 15.2, FEI does not expect any variance to be material and has no information at this time on which to quantify what that variance may be.

15.4 Please explain the financial effects on customers and on FEI if FEI fails to spend the New/Incremental Funding. Would FEI benefit from underspending? Would customers be refunded monies that are not spent? How would these monies transfer from year to year?

Response:

Under the MRP, any difference between the achieved and allowed ROE under the approved earnings sharing mechanism will be shared 50 percent with customers. This includes variances in formula O&M in the category of System Operations, Integrity and Security.

Over the term of the MRP, FEI anticipates that the total new/incremental spending in the combined categories of System Operations, Integrity and Security will be relatively close to the cumulative approved formula amounts, although there will be variations from year to year. In short, variations from year to year are expected to offset each other over the term of the MRP but there is no transfer mechanism between years.

16. Reference: Exhibit B-2, page 45

Table 6-7: Integrity Digs Activities and Expenditures

		Number of Digs per Year		
Line No.	Reason for Digs	2019	2020 Projection	2021 Forecast
1	ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment[1]	11	60	80
2	ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices[2]	45	50	40
3	Ongoing ILI digs not covered by a category above[3]	37	10	25
4	Non-ILI digs identified through above-ground cathodic protection and coating surveys	24	25	10
5	**Total Integrity Digs**	**117**	**145**	**155**
6	Total Expenditures ($000s)	$3,100	$4,400	$4,800
7	Cost per dig ($000s)	$26	$30	$31

Notes:

[1] Previously reported as "Circumferential magnetic flux leakage in-line inspection digs", which is just one example of integrity digs due to a first-time inspection with an ILI technology or ILI tool in a given pipeline segment.

[2] Previously reported as "Dent digs (includes dig selections that were influenced by the strain-based criteria)". The intent of this Reason for Dig was to capture increasing numbers of integrity digs due to a change to an industry practice or industry standard. The current wording will facilitate FEI's future reporting of other potential changes to industry practices and standards that will require a corresponding change from FEI's past integrity dig practices.

16.1 Please elaborate on the Reason for Digs in Line 1.

Response:

As indicated Table 6-7, the digs listed in Line 1 are ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment. To elaborate, the digs reported in Line 1 are those that result from FEI's analysis of "baseline" or first-time ILI data. First-time ILI data can result from a gas line being made ILI capable for the first time or from FEI applying an ILI technology or tool to a gas line for the first time. For example, through the Inland Gas Upgrade (IGU) project, FEI is making some laterals ILI capable for the first time and, through the Transmission Integrity Management Capabilities (TIMC) project, FEI is applying EMAT[7] technology for the first time. Digs resulting from these "baseline" or first-time ILI runs, but prior to re-inspection ILI runs, are shown in Line 1 in the above table.

FEI typically re-inspects its pipelines on a 5 to 7 year frequency. Digs resulting from re-inspection ILI runs are shown in Line 3 in the above table.

[7] EMAT refers to Electro-Magnetic Acoustic Transducer in-line inspection technology.

In the process of responding to this series of IRs, FEI identified an error in its allocation of digs for its 2020 Projection and 2021 Forecast between Line 1 and Line 3. FEI provides a corrected Table 6-7 below. Please note that the Total Integrity Digs in Line 5 remains unchanged, and that only the allocation of digs between Line 1 and Line 3 has been corrected. Specifically, digs attributed to or forecast from re-inspections with circumferential magnetic flux leakage (CMFL) tools were erroneously included in Line 1 in FEI's original submission, and have been moved to Line 3.

Table 6-7: Integrity Digs Activities and Expenditures

		Number of Digs per Year		
Line No.	**Reason for Digs**	**2019**	**2020 Projection**	**2021 Forecast**
1	ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment[1]	11	~~60~~ 30	~~80~~ 40
2	ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices[2]	45	50	40
3	Ongoing ILI digs not covered by a category above[3]	37	~~10~~ 40	~~25~~ 65
4	Non-ILI digs identified through above-ground cathodic protection and coating surveys	24	25	10
5	**Total Integrity Digs**	**117**	**145**	**155**
6	Total Expenditures ($000s)	$3,100	$4,400	$4,800
7	Cost per dig ($000s)	$26	$30	$31

Notes:

[1] Previously reported as "Circumferential magnetic flux leakage in-line inspection digs", which is just one example of integrity digs due to a first-time inspection with an ILI technology or ILI tool in a given pipeline segment.

[2] Previously reported as "Dent digs (includes dig selections that were influenced by the strain-based criteria)". The intent of this Reason for Dig was to capture increasing numbers of integrity digs due to a change to an industry practice or industry standard. The current wording will facilitate FEI's future reporting of other potential changes to industry practices and standards that will require a corresponding change from FEI's past integrity dig practices.

[3] Previously reported as "Other ILI digs". These are digs resulting from FEI's routine and ongoing use of previously adopted ILI technology or ILI tools.

The increases in the number of Integrity Digs in Line 1 between 2019 and 2020, and also between 2020 and 2021, are attributed to FEI's adoption of EMAT technology in its pipeline system as part of the TIMC project. FEI ran its first "baseline" EMAT tool in Q4 2019 on the Livingstone Pattullo 457 pipeline, and is forecasting integrity digs on this pipeline in 2020, 2021, and subsequent years. FEI recently ran its second "baseline" EMAT tool in Q3 2020 on a section of the Cape Horn Burrard Thermal 508 pipeline, and is forecasting a majority of these integrity digs in 2021.

The revised table above shows a larger increase in the number of Integrity Digs in Line 3 (re-inspections) between 2020 and 2021, which is attributable to FEI's adoption in late 2013 of CMFL technology in its pipeline system. As FEI's ILI re-inspections typically occur on a 5 to 7 year frequency, FEI is starting to have re-inspections with the CMFL technology.

16.2 Please explain the reason for the fivefold increase in the number of Integrity Digs under Line 1 between 2019 and 2020.

Response:

Please refer to the response to CEC IR1 16.1.

16.2.1 Why does FEI expect these digs to increase by another 30% in 2021?

Response:

Please refer to the response to CEC IR1 16.1.

17. Reference: Exhibit B-2, page 48

Table 6-8: Biomethane O&M by Project ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Program Overhead	0.986	0.470	1.058	1.079
2	City of Surrey	0.010	0.010	0.010	0.010
3	Kelowna Upgrader	0.147	0.403	0.492	0.502
4	Salmon Arm Upgrader	0.180	0.276	0.194	0.194
5					
6	Fraser Valley Biogas	0.011	0.011	0.010	0.010
7	Salmon Arm Landfill	0.011	0.011	0.010	0.010
8	Kelowna Landfill	0.011	0.011	0.010	0.010
9	Seabreeze Farms	0.011	0.011	0.010	0.010
10	Lulu Island WWTP	0.001	0.001	0.003	0.010
11	Dickland Farms	-	-	0.010	0.010
12	Total Biomethane O&M	1.369	1.205	1.807	1.848

[1] Prior to order G-165-20 lines 1-4 were transferred to the BVA and lines 6-11 remained in delivery rates. Order G-165-20 approves the legacy interconnection charges to be accounted in the BVA, this results in the total Biomethane O&M (line 12) being transferred to the BVA.

The 2020 Projected and 2021 Forecast total Biomethane O&M is $1.807 million and $1.848 million, respectively.

The 2020 Projected Biomethane O&M of $1.807 million is $0.438 million higher than the 2019 Approved O&M of $1.369 million. This is primarily due to increased run time and maintenance costs of the Kelowna upgrader.

The 2021 Forecast Biomethane O&M of $1.848 million is in line with the 2020 Projected amount with the increase due to inflation.

17.1 Please provide further details of the costs included in the Program Overhead, and explain why these have increased by about $600,000 relative to 2019 Actual.

Response:

The Actual Program Overhead costs in 2019 are lower relative to the forecast and approved costs due to a one-time allocation of $635 thousand from Program Overhead to the City of Vancouver Landfill biomethane project approved by Order G-235-19. Without the allocation credit of $635 thousand in 2019, the Program Overhead costs would have been approximately $1.105 million in that year. More information on this allocation follows.

The City of Vancouver Landfill biomethane project costs that were incurred in 2018 were allocated to Program Overhead resulting in higher costs in that reporting year. The costs for the City of Vancouver project incurred in 2018 were a result of work on the pipeline required to

connect the City of Vancouver Landfill biomethane upgrading plant to FEI's existing natural gas pipeline. The construction was undertaken ahead of BCUC approval of the City of Vancouver Landfill biomethane project to coincide with planned work by the City of Vancouver at the landfill. By installing the interconnection pipeline at the same time as the work done at the landfill, FEI was able to realize cost savings for the biomethane project. Once the BCUC granted approval for the City of Vancouver landfill biomethane project in 2019, the costs incurred in 2018 were moved to the project, out of Program Overhead.

The 2019 variance between Actual and Approved, without the allocation credit, of approximately $119 thousand was due to increased activities in developing new biomethane projects. Therefore, there is no significant increase in the relative costs in Program Overhead between Actual 2019 and Projected 2020.

17.2 Please explain the reason for the increase in the run time and maintenance costs of the Kelowna upgrader relative to 2019 Approved.

Response:

The variance in the 2019 Actual expenditures to Approved expenditures for the Kelowna upgrader was $256 thousand. The variance resulted from two items: an insurance recovery received from an incident at the facility was lower than forecast, and facility run time and maintenance costs were higher than forecast.

The Approved 2019 amount of $147 thousand, which was based on a forecast prepared in 2018, included a forecast credit of $213 thousand related to an insurance claim. The actual insurance amount received and credited to the Kelowna project in 2019 was $114 thousand, which was $99 thousand lower than the forecast of $213 thousand.

When the forecast insurance credit of $213 thousand is added back to the 2019 Approved O&M for Kelowna, the Adjusted Approved O&M amount excluding the insurance credit equals $360 thousand. The Actual O&M cost for Kelowna in 2019 was $517[8] thousand, resulting in a variance of $157 thousand over the Adjusted Approved O&M amount of $360 thousand. This variance was a result of higher than expected costs for plant electricity and consumables over the calendar year because the plant operated for a greater percentage of time than forecast.

[8] Actual 2019 equals $0.517 million less the $0.114 million insurance credit equaling the $0.403 million from Table 6-8 in the preamble.

18. Reference: Exhibit B-2, page 49 and page 14

6.3.7 Clean Growth Initiative - NGT O&M

NGT O&M is comprised of O&M expenses related to the operation of the FEI-owned CNG and LNG fuelling stations and FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M.

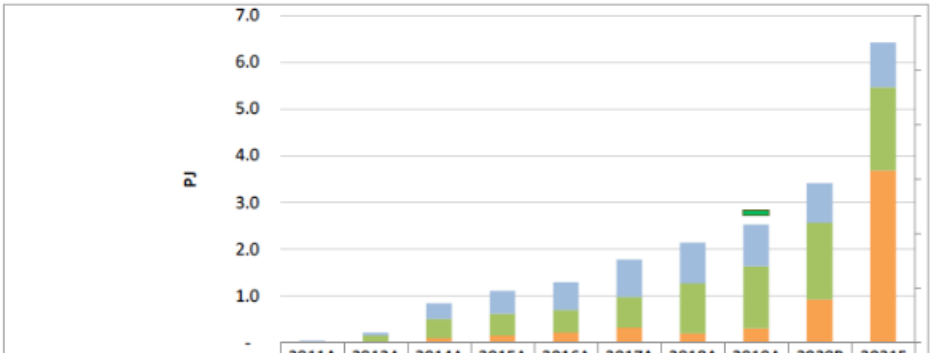
Table 6-10: NGT O&M ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	CNG Stations	0.929	0.778	0.791	0.856
2	LNG Stations	0.540	0.741	0.303	0.311
3	LNG Tankers	0.770	0.495	0.500	0.545
4	Emergency Response and Preparedness (ERAP)	0.100	0.046	0.100	0.100
5	**Total NGT O&M**	**2.339**	**2.060**	**1.694**	**1.813**

The 2020 Projected O&M expense is approximately $0.645 million less than the 2019 Approved O&M. This is primarily due to the closure of three LNG stations and the anticipated completion of two transit CNG facilities in 2019 which did not occur as the two organizations did not proceed with FEI.

The NGT O&M for 2021 is forecast to increase by approximately $0.119 million from the 2020 Projected level. This is primarily due to the incremental increase of CNG and LNG demand from 2020 Projected to 2021 Forecast as discussed in Section 3.3.4 of this Application.

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[17]



	2011A	2012A	2014A	2015A	2016A	2017A	2018A	2019A	2020P	2021F
RS 3/5/23/25/6P - CNG (NGT)	0.0	0.1	0.3	0.5	0.6	0.8	0.9	0.9	0.8	1.0
RS 46 - LNG (NGT)	0.0	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.6	1.8
RS 46 - LNG (Non-NGT)	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.9	3.7
2019 Approved								2.8		
Total CNG & LNG	0.0	0.2	0.8	1.1	1.3	1.8	2.1	2.5	3.4	6.4

The 2020 Projected demand is approximately 0.9 PJ higher than the 2019 Actual demand of 2.5 PJs. Of this 0.9 PJ increase, approximately 0.3 PJ (or approximately 30.2 percent) is attributed to demand that serves NGT customers while the rest of the increase is attributed to non-NGT demand involving LNG exports (approximately 0.6 PJ or 69.8 percent).

For 2021, the CNG demand for NGT customers is forecasted to increase by approximately 0.11 PJ (approximately 13 percent) from the 2020 Projected level. This is primarily attributable to incremental load from existing customers and two new CNG stations to be in-service starting in mid-2020 with demand ramp up by 2021. The LNG demand for NGT customers is forecast to increase by approximately 0.14 PJ (approximately 9 percent) from the 2020 Projected level which is primarily attributed to increased volumes from BC Ferries and Seaspan due to two additional fleet vessels.

18.1 Please explain the reasons why the two transit CNG customers did not proceed with FEI.

Response:

FEI participated in the formal bid process for the construction and ownership of a CNG station with the two CNG transit customers. FEI's business model involves FEI constructing the station and recovering a capital fee from the participating customer, and providing the related station maintenance and operation. After going through the procurement process, the two transit agencies decided to deploy their own capital and chose a third party service provider for O&M for the stations, as they have done historically.

18.2 Please provide a brief discussion of the status of the two new CNG stations that are expected to be in-service in mid-2020.

Response:

Please refer to the response to CEC IR1 9.2.

18.2.1 If the two new CNG stations have not been finalized yet, please explain if there is risk that these customers will also not proceed.

Response:

Please refer to the response to CEC IR1 9.2.

19. Reference: Exhibit B-2, page 50

Table 6-11: Variable LNG Production O&M ($ millions)[39]

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Tilbury Plant:				
2	Labour	n/a	n/a	1.375	1.650
3	Materials	n/a	n/a	1.000	0.540
4	Contractor	n/a	n/a	1.365	1.131
5	Power	n/a	n/a	3.200	3.813
7	Fees and Employee Expenses	n/a	n/a	0.300	0.308
8	Sub-total	n/a	n/a	7.240	7.443
9	Mt. Hayes Plant				
10	Labour	n/a	n/a	0.306	0.315
11	Materials	n/a	n/a	0.025	0.026
12	Contractor	n/a	n/a	0.054	0.056
13	Power	n/a	n/a	0.236	0.243
14	Fees and Employee Expenses	n/a	n/a	0.000	0.000
16	Sub-total	n/a	n/a	0.621	0.639
17	Forecast O&M	na	n/a	7.861	8.081

19.1 Please explain why FEI does not provide variable production costs for 2019.

Response:

For 2019 and other years within the previous PBR Plan term, tracking of LNG O&M costs was in the two categories of Base O&M and flow-through Rate Schedule 46 O&M, instead of the new cost allocation approach of Fixed O&M being included in Base O&M and Variable Production O&M being subject to flow-through, as approved by the BCUC for the MRP term. As a result, FEI did not provide the 2019 Actual Variable LNG O&M costs in the table as they were not relevant to that time period. Additionally, as 2019 was under the previous PBR Plan term, there was no BCUC Approved amount for LNG Variable Production O&M to compare.

For the Actual and Approved 2019 Rate Schedule 46 O&M costs (which was the relevant flow-through item in the PBR term), please refer to Table 6-4.

20. Reference: Exhibit B-2, page 52

> **7.1 INTRODUCTION AND OVERVIEW**
>
> Rate Base for FEI is forecast to be $5.047 billion for 2020 and $5.213 billion for 2021. Rate Base is comprised of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

20.1 Please confirm or otherwise explain that LILO refers to Lease In Lease Out.

Response:

Confirmed.

20.2 Please provide a brief description of the LILO benefit.

Response:

The LILO benefit pertains to the customer portion of the benefits from entering into the LILO arrangements that started in 2001. Upon closing of the LILO transactions, the customers received a reduction to rate base equal to 50 percent of the NPV of future benefits to be received from the LILO arrangements. This rate base reduction effectively reduced customer rates to be lower than they otherwise would have been and ensured that customers would receive their share of the benefits over the long term.

The LILO benefit reduces each year by the rate of depreciation for the term of the remaining LILOs, with the last agreement expiring in 2022.

21. Reference: Exhibit B-2, page 55 and 56

Biomethane Upgraders and Interconnect

The 2019 Actual amounts were less than expected due to the timing of construction of biomethane projects. In the Biomethane Upgrader category, the majority of the original approved amount was allocated to the City of Vancouver Biomethane project, which has been delayed based on the approval date of September 2019 and slower than expected initial spending. It is expected that the full amount will be moved into future years. The interconnect portion of capital is set aside for FEI costs related to new supply not owned by FEI. These costs were not incurred due to delays in supplier execution of their projects.

The following table provides additional detail by project for the 2020 and 2021 Biomethane upgrader and interconnect capital projection and forecast, including the Order approving the project.

Table 7-5: Biomethane CapEx

Line No.	Description	Order	Projected 2020	Forecast 2021
1	City of Vancouver	G-235-19	2.070	15.570
2	Kelowna Upgrader	E-19-12	0.700	0.120
3	Salmon Arm Upgrader	G-194-10	0.120	-
4	Total Biomethane Upgraders		2.890	15.690
5				
6	Lulu Island WWTP	E-13-13	1.380	0.020
7	Dickland Farms	E-13-20	0.100	1.230
8	City of Vancouver	G-235-19	0.230	1.730
9	Ren Energy	G-60-20	0.100	1.480
10	Seabreeze Farms	E-11-19	0.100	-
11	Total Biomethane Interconnect		1.910	4.460
12				
13	Total Biomethane Upgraders & Interconnect		4.800	20.150

21.1 What additional reporting is available to the Commission on Biomethane projects? Please explain.

Response:

Please refer to the response to BCSEA IR1 6.2.

22. Reference: Exhibit B-2, page 57

Table 7-6: NGT Assets Capital Expenditures[42]

Line No.	Description	BCUC Order	Projected 2020	Forecast 2021
1	E360S (CNG)	G-237-19	(0.036)	-
2	Fresh Direct (CNG)	G-238-19	0.110	-
3	London Drug (CNG)	G-299-19	0.195	-
4	Waste Connections Expansion (CNG)	G-110-20	0.180	-
5	Waste Management Expansion (CNG)	G-77-20	0.264	-
6	Annacis Island (CNG)	To be filed	1.895	-
7	Cumberland (CNG)	To be filed	0.950	0.950
8	Waste Connections Abbotsford (CNG)	To be filed	0.721	0.080
9	Prince George (CNG)	To be filed	-	1.000
10	District of Cowichan (CNG)	To be filed	-	1.000
11	LNG Tanker (LNG)	GGRR	(0.201)	2.000
12	**Total NGT Capital Expenditures**		**4.079**	**5.030**

22.1 What additional reporting is available to the Commission on NGT related capital expenditures?

Response:

Under sections 18(4) and (5) of the *Clean Energy Act*, FEI is required to report on its prescribed undertakings under the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR) to the Province of British Columbia. The reporting includes details on the NGT related capital expenditures for all stations constructed under the GGRR. FEI submits the report annually to the Ministry of Energy Mines and Petroleum Resources with a copy to the BCUC.

23. Reference: Exhibit B-2, page 64

> ***7.5.1.1 Annual Reviews for 2020 – 2024 Rates***
>
> FEI is requesting approval to establish a deferral account to capture the costs related to the Annual Reviews for 2020 – 2024 Rates. Consistent with other deferral accounts related to regulatory applications, the Annual Review deferral account will capture costs such as BCUC costs, intervener and participant funding costs, consulting costs, legal fees, and miscellaneous facilities, stationary and supplies costs. FEI forecasts additions of $0.100 million ($0.073 million after tax) in each of 2020 and 2021.
>
> Consistent with past practice, FEI is proposing to amortize costs over one year, whereby costs related to each annual review will be amortized in the subsequent year.

23.1 Will the deferral account attract interest? Please explain.

23.1.1 If yes, please provide the expected interest.

Response:

The Annual Review for 2020 – 2024 Rates deferral account is a rate base deferral account. As such, it will attract a weighted average cost of capital rate of 5.47 percent, which includes an after-tax interest rate of 3.41 percent in 2020 and 3.42 percent in 2021.

24. Reference: Exhibit B-2, page 67

Table 7-10: 2022 LTGRP Estimated Expenditures

Activity	Total Estimated Expenditures
Scenario Development	$ 75,000
Comparison of Demand Forecasting Methodologies	$ 45,000
End-Use Demand Forecast	$ 150,000
Alternative Residential and Commercial Customer Additions Forecast	$ -
Alternative Industrial Customer Additions and Demand Analysis	$ 50,000
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 115,000
Incremental Consultation Activities	$ 50,000
DSM Portfolio Scenario Analysis & Alternative DSM Funding and Savings Scenarios	$ 90,000
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000
Infrastructure Contingency Plans	$ 20,000
Analysis of Impact on GHG Targets	$ 20,000
Addressing Security of Supply / Resiliency	$ 50,000
Address Implications of the CleanBC Plan / Initiatives being Developed by the Provincial Government	$ 50,000
Additional Regulatory Assistance (if needed)	$ 55,000
Total	$ 850,000

24.1 Please provide a brief description as to what information FEI used to derive the estimates.

Response:

Please refer to the response to BCUC IR1 21.1 for the requested description.

24.2 Please provide the cost of FEI's last 2 LTGRPs, broken down into similar activities if possible.

Response:

The last two Long Term Gas Resource Plans were the 2014 LTRP and the 2017 LTGRP. For the 2014 LTRP, the costs were captured in O&M as per the approved 2012-2013 Revenue

Requirement Application (2012-2013 RRA). As such, the costs were not tracked in the same way that they were within the deferral account for the 2017 LTGRP or the proposed 2022 LTGRP. Further, the nature of these activities has evolved since the preparation of the 2014 LTRP. These two factors prevent a meaningful comparison of the 2014 LTRP costs with the requested deferral account breakdown.

As part of its Decision on the 2014-2019 Performance Based Ratemaking Plan (Order G-138-14), the BCUC directed FEI to reduce its O&M expenditures by the amount identified for the LTRP activities in the 2012-2013 RRA. As a result, FEI requested deferral account treatment of these costs and began tracking them as part of the deferral account for the 2017 LTGRP. The table below presents both the estimated expenditures that were approved by the BCUC for the 2017 LTGRP deferral account and the actual costs captured in the 2017 LTGRP deferral account. The activities listed in the table below do not reflect the enhancements to those activities that FEI undertook for the 2017 LTGRP or any of the new incremental activities that are required for the 2022 LTGRP.

2017 LTGRP Deferral Account Approved and Actual Costs by Activity Type

Activity	Total Approved Expenditure	Actual Costs
Scenario Development	$ 75,000	$ 74,300
Comparison of End-Use Demand Forecasting Methodologies	$ 45,000	$ 45,000
Alternative Residential and Commercial Customer Additions Forecast	$ 25,000	Not available
End-Use Demand Forecast	$ 180,000	$ 141,500
Alternative Industrial Customer Additions and Demand Analysis	$ 145,000	Not available
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 150,000	$ 110,900
Incremental Consultation Activities	$ 50,000	$ 42,600
DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 200,000	$ 125,400
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000	Not available
Infrastructure Contingency Plans	$ 70,000	Not available
Analysis of Impact on GHG Targets	$ 30,000	Not available
Total	**$ 1,050,000**	**$ 539,700**

For those actual costs shown as “Not available” for the 2017 LTGRP, FEI was able to complete the analysis internally rather than requiring outsourcing. For the 2022 LTGRP, FEI does not expect internal resources will be available to complete these activities and so FEI plans instead to outsource these activities, with costs to be recorded in the proposed deferral account. However, to the extent that FEI is able to complete any of the items listed in Table 7-10

1 internally with available resources during the 2022 LTGRP process, those costs will not be
2 added to the deferral account.

3

25. Reference: Exhibit B-2, pages 67-68

> ***7.5.1.3 BCUC-Initiated Inquiries***
>
> FEI is seeking a deferral account to capture, in aggregate, costs associated with its participation in BCUC-initiated inquiries and proceedings for the purpose of determining provincial regulatory policy or ensuring consistency of treatment among utilities. These costs represent BCUC costs, intervener and participant funding costs, consulting costs and external legal fees. The following proceedings are currently included or will be included in this deferral account:
>
> - BCUC Indigenous Utilities Regulation Inquiry, which concluded in April 2020. To date, FEI has incurred $0.487 million ($0.356 million after tax) and anticipates additional costs of $0.125 million in 2020 related to the issuance of the final report and participant funding costs.
> - BCUC Inquiries, which include the Municipal Energy Utilities Inquiry and Thermal Energy Systems Guidelines Review. To date, FEI has incurred $0.096 million ($0.070 million after tax). FEI forecasts further costs of $0.070 million in 2020 and $0.100 million in 2021 related these inquiries.
>
> FEI proposes to include the costs of these and future BCUC-initiated inquiries in a single deferral account in order to reduce the number of individual deferral account requests. Further, FEI proposes to amortize costs in the year following when the expenses are forecast.

25.1 Would the BCUC Initiated Inquiries deferral account attract interest? Please explain.

25.1.1 If yes, what interest rate would be applicable?

Response:

The BCUC-Initiated Inquires deferral account is a rate base deferral account. As such, it will attract a weighted average cost of capital rate of 5.47 percent, which includes an after-tax interest rate of 3.41 percent in 2020 and 3.42 percent in 2021.

26. Reference: Exhibit B-2, page 68

> ***7.5.1.4 City of Coquitlam Application Proceeding***
>
> FEI is requesting approval for a deferral account to capture costs related to the ongoing dispute with the City of Coquitlam regarding the use of land that arose from the LMIPSU Project. As part of the BCUC's approval of the LMIPSU CPCN, FEI was granted approval to proceed with the LMIPSU Project; however, the City of Coquitlam was unwilling to issue the necessary permits. FEI filed an application to the BCUC and received a decision to direct the use of the land without the City of Coquitlam's permits. The City of Coquitlam challenged the decision both through the BCUC on reconsideration of their decision and by filing an application for Leave to Appeal with the Court of Appeal. The BCUC's reconsideration process has been completed, dismissing the City's Reconsideration Application. However, the regulatory process related to the allocation of any pipeline removal costs is ongoing. The City of Coquitlam is also pursuing its Leave to Appeal.
>
> To date, FEI has incurred costs of $0.285 million ($0.208 million after tax) for legal fees, BCUC costs and consulting fees. FEI anticipates further costs related to this proceeding and any ongoing legal proceedings through the courts. At this time, these costs are estimated to be an additional $0.100 million ($0.073 million after tax) in 2020 and $0.250 million ($0.183 million after tax) in 2021; however, these costs are only a best estimate at this time and there is uncertainty over the remainder of the process.
>
> Further, FEI proposes to amortize these costs over 3 years beginning January 1, 2021. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period of other similar regulatory proceeding applications and it balances potential rate impacts with the benefits of the application.

26.1 Why does FEI believe that 3 years is the appropriate term for amortization for these costs?

Response:

FEI believes a three-year amortization period is appropriate because it is consistent with other recovery periods for regulatory proceeding-related costs. The benefits of the City of Coquitlam Application Proceeding should extend much longer than the suggested recovery period since they are attributable to the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) capital project. However, given the amount of the expenditures, it is not necessary to recover the costs over a longer period of time, and a shorter amortization period of 3 years will not put undue pressure on delivery rates.

26.2 Depending on the remaining process, and the outcomes, are there any opportunities for FEI to recover costs from the City of Coquitlam? Please explain.

Response:

Section 23 of the *Court of Appeal Act* provides that unless otherwise ordered, the successful party on appeal is entitled to the costs of the appeal, including the costs of all applications made in the appeal. However, costs are usually determined based on a tariff and, therefore, do not represent a full recovery of the party's legal costs. Therefore, depending on the outcome, FEI may be entitled to recover some costs from the City. If FEI does receive any recoveries, they will be credited to the deferral account.

26.3 Will the City of Coquitlam deferral account attract interest? If yes, please provide.

Response:

The City of Coquitlam deferral account is a rate base deferral account. As such, it will attract a weighted average cost of capital rate of 5.47 percent, which includes an after-tax interest rate of 3.41 percent in 2020 and 3.42 percent in 2021.

27. Reference: Exhibit B-2, page 69

a) Bill payment deferrals provided to residential and small commercial customers

The 3-month bill payment deferral program has been offered to residential and small commercial customers affected by COVID-19 from April to June 2020. The bill payment deferrals are to be repaid by customers over a 12-month period with such repayments beginning in July 2020.

Table 7-11: 2020 Bill payment deferral forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	2020	-	1,625	-	-	1,625
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	2021	1,625	(1,625)	-	-	-

The deferral account gross additions of $1.625 million related to this customer relief offering have been estimated as the outstanding customer accounts receivable balances of $3.652 million as of July 2020, less the estimated customer repayments from July 2020 through to the end of 2020. As customers are expected to repay the balances over a 12-month term, beginning in July 2020, there is not expected to be an ending balance of bill payment deferral balances as at the end of 2021.

Any of the customers enrolled in the bill payment deferral program that are unable to repay their outstanding balances will be designated as unrecoverable revenue. This change in classification will entail a reduction in the bill payment deferral portion of the deferral account in this section (a) and will be reallocated as an addition to the unrecovered revenue (section c) component. There could be customers that default on their repayment of the bill deferral arrangements and these would also be allocated to the unrecovered revenue (section c). No such defaults have been forecasted in section (a) as they are assumed to be incorporated in the estimates provided in section (c) associated with unrecovered revenue.

27.1 Please provide the additions to the Recovery Fund bill payment deferral by customer class and by month.

Response:

Please refer to the table below for a forecast monthly breakdown.

Residential Bill Payment Deferrals

Amounts in $'000s

	31-May-20 (1)	30-Jun-20	31-Jul-20 (2)	31-Aug-20	30-Sep-20	31-Oct-20	30-Nov-20	31-Dec-20
Opening balance	-	2,616	2,829	2,256	2,051	1,846	1,641	1,436
Additions	2,616	213	-	-	-	-	-	-
Repayments	-	-	(573)	(205)	(205)	(205)	(205)	(205)
Ending balance	**2,616**	**2,829**	**2,256**	**2,051**	**1,846**	**1,641**	**1,436**	**1,231**

	01-Jan-21	28-Feb-21	31-Mar-21	30-Apr-21	31-May-21	30-Jun-21
Opening balance	1,231	1,025	820	615	410	205
Additions	-	-	-	-	-	-
Repayments	(205)	(205)	(205)	(205)	(205)	(205)
Ending balance	**1,025**	**820**	**615**	**410**	**205**	**-**

Small Commercial Bill Payment Deferrals

Amounts in $'000s

	31-May-20 (1)	30-Jun-20	31-Jul-20 (2)	31-Aug-20	30-Sep-20	31-Oct-20	30-Nov-20	31-Dec-20
Opening balance	-	963	926	723	658	592	526	460
Additions	963	(37)	-	-	-	-	-	-
Repayments	-	-	(203)	(66)	(66)	(66)	(66)	(66)
Ending balance	**963**	**926**	**723**	**658**	**592**	**526**	**460**	**395**

	01-Jan-21	28-Feb-21	31-Mar-21	30-Apr-21	31-May-21	30-Jun-21
Opening balance	395	329	263	197	132	66
Additions	-	-	-	-	-	-
Repayments	(66)	(66)	(66)	(66)	(66)	(66)
Ending balance	**329**	**263**	**197**	**132**	**66**	**-**

Notes:

(1) FEI considers the balances at May 31, 2020 to include the first complete month of program activity, given the variability of when customer billing cycles complete.

(2) Monthly amounts shown prior to July 31, 2020 were estimated based on outstanding customer balances and balances were validated in July at the end of the eligible deferment period.

28. Reference: Exhibit B-2, page 70

c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

Unrecovered revenues are representative of accounts receivable balances that are determined to be uncollectible due to COVID-19 and therefore include the write-offs of bad debts. These forecasted balances are meant to represent the unrecovered revenues specific to COVID-19 that are recognized in the deferral account and therefore are in excess of the normal course forecasted bad debt expense that is recognized in indexed-based O&M. While FEI has currently forecasted the bad debt expense to be recognized in indexed-based O&M for 2020 and 2021 as representative of the normalized bad debt expense that was embedded in the Base O&M, the actual bad debt expense recognized in O&M could differ. This is in part due to the timing of recognizing the bad debt expense in O&M versus the write-offs of bad debts in the deferral account, as well as the uncertainty around the duration and significance of the pandemic on customers' ability to pay their bills.

Table 7-13: 2020 Unrecoverable Revenue Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	2020	-	2,026	(547)		1,479
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	2021	1,479	3,683	(994)	-	4,168

28.1 Please breakdown the balances of Unrecoverable Revenue by customer class and by month.

Response:

The forecasted additions to the deferral account, which commence in September 2020, are representative of forecast write-offs attributable to the COVID-19 pandemic and have been forecast based on principles of US GAAP ASU 2016-13 Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments. Please refer to the table below for the forecast additions by rate class and month.

2020 Unrecoverable Revenue Forecast

Amounts in $'000s

Customer class	30-Sep-20	31-Oct-20	30-Nov-20	31-Dec-20	Total
Residential	71	111	72	62	**316**
Small commercial	22	30	18	16	**86**
Large commercial	130	192	111	106	**539**
Industrial/Transportation	177	327	336	245	**1,085**
Total	400	660	537	429	**2,026**

2021 Unrecoverable Revenue Forecast [(1)]

Amounts in $'000s

Customer class	31-Jan-21	28-Feb-21	31-Mar-21	30-Apr-21	31-May-21	30-Jun-21	Total
Residential	53	52	60	105	164	205	**639**
Small commercial	16	16	18	31	50	66	**197**
Large commercial	89	86	102	178	251	319	**1,025**
Industrial/Transportation	221	228	243	342	380	408	**1,822**
Total	379	382	423	656	845	998	**3,683**

Note:

(1) Due to the timing of collection cycles, the 2021 deferral account additions are representative of write-offs related to revenues billed in 2020, which is why the additions end in June 2021.

There is uncertainty around the duration and significance of the pandemic on customers' ability to pay their bills, with the potential for unrecoverable revenue to shift between periods or vary from the forecast.

29. Reference: Exhibit B-2, page Exhibit B-2, page 71

b) Bill credits provided to small commercial customers

The 3-month bill credit program offered to small commercial customers for April through June 2020 has been estimated using the customer balances of $0.918 million as of July 2020.

Table 7-12: 2020 Bill Credit Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Credits	**2020**	-	918	(248)	-	670
COVID-19 Customer Recovery Fund - Bill Credits	**2021**	670	-	-	-	670

The deferral account gross additions of $1.625 million related to this customer relief offering have been estimated as the outstanding customer accounts receivable balances of $3.652 million as of July 2020, less the estimated customer repayments from July 2020 through to the end of 2020. As customers are expected to repay the balances over a 12-month term, beginning in July 2020, there is not expected to be an ending balance of bill payment deferral balances as at the end of 2021.

Any of the customers enrolled in the bill payment deferral program that are unable to repay their outstanding balances will be designated as unrecoverable revenue. This change in classification will entail a reduction in the bill payment deferral portion of the deferral account in this section (a) and will be reallocated as an addition to the unrecovered revenue (section c) component. There could be customers that default on their repayment of the bill deferral arrangements and these would also be allocated to the unrecovered revenue (section c). No such defaults have been forecasted in section (a) as they are assumed to be incorporated in the estimates provided in section (c) associated with unrecovered revenue.

29.1 Please update the bill credits with current information if available.

Response:

Since the date of filing the Application, which included $918 thousand of bill credit additions through to August 31, 2020, there has only been an additional $2 thousand of additional credits offered to eligible customers. Please refer to an updated Table 7-12 below.

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Credits	**2020**	-	920	(248)	-	672
COVID-19 Customer Recovery Fund - Bill Credits	**2021**	672	-	-	-	672

29.2 Please breakdown the additions by month.

Response:

As reflected in the response to CEC IR1 29.1, Table 7-12 has been updated to include August 2020. As such, the estimated and actual bill credits per month, including August 2020, are as follows:

Small Commercial Bill Credits

Amounts in $'000s

	31-May-20	30-Jun-20	31-Jul-20	31-Aug-20	Total
Additions	342	115	461	2	920

29.3 Please describe the options available to medium and large general service customers, and how these will be dealt with by FEI.

Response:

FEI interprets the reference to medium and large general service customers to be in reference to FEI's large commercial (Rate Schedule 3 and 23 customers) and industrial customer rate schedules, which FEI also refers to as larger volume customers.

FEI is working with medium and large customers on an individual basis to address their unique needs during the pandemic, whether those needs relate to creating customized payment arrangements, pausing disconnections, or providing customized energy advice and energy efficiency options. This customized approach provides an opportunity for the larger volume customers that are significantly challenged by the pandemic to receive the support they need based on their unique business scenario, while avoiding the potentially large financial impact that could result from a utility-wide program. FEI has received very positive feedback from this customer segment noting that the approach is effective in managing a difficult time for many of these customers.

29.4 Please identify any credits or other relief that has been provided to medium or large commercial customers; and provide quantification by customer class.

Response:

FEI is committed to supporting medium and large commercial customers throughout the pandemic and has been working closely with them to provide assistance. While no bill credits are being provided and therefore no quantification is possible, FEI is providing various relief measures based on the individual needs of the customer.

As the commercial sector is quite diverse, the nature of the requests and subsequent support provided also varies, so FEI works with customers on a case-by-case basis to assist them. The nature of relief measures that have been provided range from deferring bill payments, flexible re-payment schedules, and continued waiver of late payment charges. Some additional ways that FEI is providing support to medium and large customers is by providing energy efficiency advice and financial incentives for equipment upgrades. FEI has also co-hosted webinars with industry associations for commercial sector customers that provide an overview of program offerings and energy efficiency advice for businesses during the pandemic.

30. Reference: Exhibit B-2, page 71

> Applying macroeconomic factors to estimating unrecoverable revenues is consistent with the principles for external financial reporting. US GAAP ASU 2016-13 *Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments* discussed in Section 12.3.1.1 of this Application requires entities to consider historical experience, current conditions and reasonable forecasts to determine the expected amount of credit losses that will occur. Accordingly, FEI has estimated $2.0 million and $3.7 million of unrecoverable revenue additions for 2020 and 2021, respectively, to the COVID-19 Customer Recovery Fund Deferral Account.
>
> While the forecasts of the unrecovered revenue additions rely on estimates and broader macroeconomic factors, the actual amounts that accumulate in the deferral account are expected to be representative of balances that are attributable to specific customers that cannot make payment due to COVID-19.
>
> There has been a minimal amount of confirmed customer bad debt write-offs relating to COVID-19 in the first four to five months since the relief options have been offered to customers. While there still exists uncertainty around the effects of COVID-19 on customers' ability to make payments for current and future billed revenues, it is probable and reasonable to expect that unrecovered revenue will materialize in the last half of 2020 and through 2021. Accordingly, FEI has developed a methodology to estimate additions to the deferral account by applying an estimated loss rate on forecasted 2020 revenues to determine the potential unrecovered revenue from customers resulting from the COVID-19 pandemic. To clarify, the ending balance of $4.168 million is based on the estimated bad debt write offs calculated on revenues billed in 2020 and does not take into account bad debt write offs associated with revenue billed in 2021 or beyond. Due to the significant uncertainty around the extent and duration of the pandemic on FEI's customers' ability to pay in the future, there could also be unrecovered revenues that are recognized in the deferral account beyond the forecast periods of 2020 and 2021.
>
> For residential and small commercial customers, the loss rate took into account the relative increase in the forecasted 2020 unemployment rate for BC from 5.0 percent prior to the pandemic to 8.2 percent. Similarly, there was a loss rate applied for industrial and large commercial customers which incorporated the forecasted 2020 GDP decrease in BC of 4.5 percent. The loss rate was then applied to forecasted revenues from March 2020 through to December 2020. The unemployment and GDP indicators are macroeconomic factors based on forecasts from five financial institutions and corroborated through the Conference Board of Canada.

30.1 Please confirm or otherwise explain the CEC's interpretation of the above that 'the worst is yet to come' from a bad debt perspective.

Response:

FEI has currently experienced minimal unrecovered revenue, but it is likely that unrecovered revenue will materialize later in 2020 and into 2021. FEI therefore expects bad debts to grow, and in that sense confirms that "the worst is yet to come".

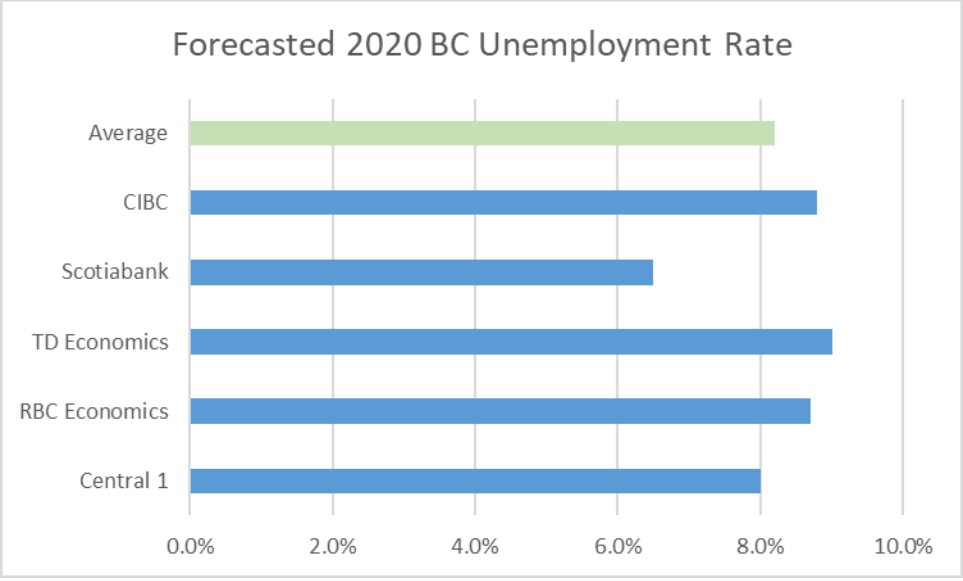
30.2 Please provide the date and source of the 8.2% unemployment rate.

Response:

The 8.2 percent unemployment rate represents the forecast rate in BC at the end of 2020. The rate was derived by using an average of five financial institutions' 2020 forecasts. These institutions' reports have been listed below with the corresponding date of publication.

- CIBC Economics - Forecast Update, April 2020
- Scotiabank Global - Economics Forecast Update, March 2020
- TD Economics - Provincial Economic Forecast, June 2020
- RBC Economics – Provincial Outlook, June 2020
- Central 1 – Economic Analysis of British Columbia, April 2020

The graph below summarizes the forecast rates included in each report, and includes the average rate of 8.2 percent utilized by FEI.

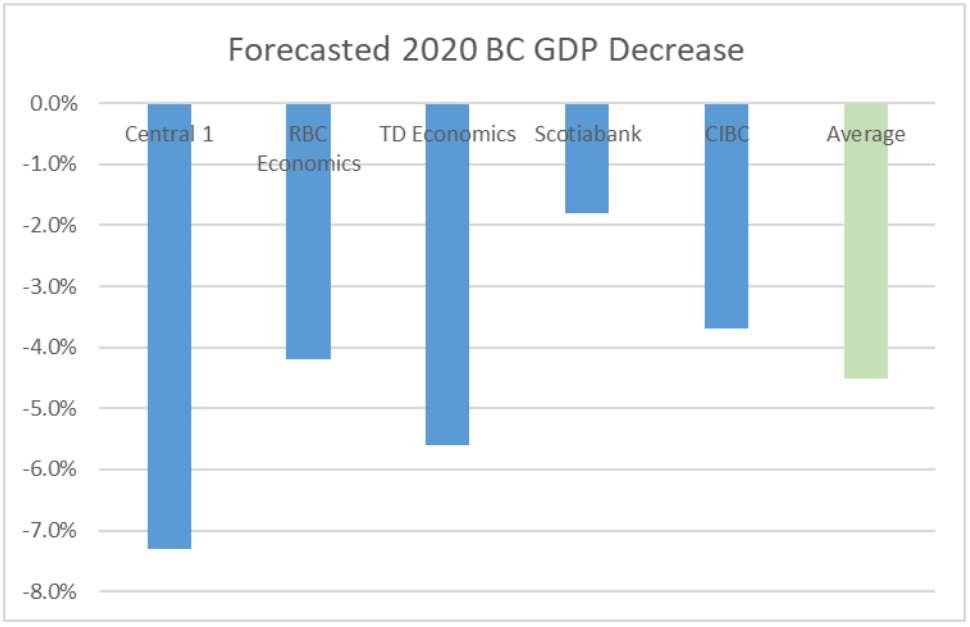


This average rate was also corroborated with the forecast 2020 unemployment rate through the Conference Board of Canada's June 2020 *Provincial Outlook British Columbia* report, which includes a forecast unemployment rate of 7.6 percent.

30.3 Please provide the date and source of the GDP decrease in BC of 4.5%.

Response:

The 4.5 percent forecast decrease in GDP for 2020 is an average of five financial institutions' forecasts, which are provided in the response to CEC IR1 30.2. Please refer to the graph below.



This average rate was also corroborated with the forecast 2020 unemployment rate through the Conference Board of Canada's June 2020 *Provincial Outlook British Columbia* report, which includes a forecast GDP decrease of 3.8 percent.

31. Reference: Exhibit B-2, page 90

10.2.3 Clean Growth Innovation Fund (CGIF)

The collection of the $0.40 per month innovation rider commenced on August 1, 2020 and is projected to collect $2.1 million in 2020 and forecast to collect $5.1 million in 2021. The shortened timeframe for portfolio approvals in 2020 will result in lower CGIF expenditures in 2020 at an estimated $1.5 million. Expenditures for 2021 are forecast to be $5.0 million.

The governance processes that will help maximize the potential of the CGIF are being established. The FEI steering teams that will review and approve portfolios are in place and the recruitment of members for the External Advisory Council is underway. Approval of the first CGIF expenditure portfolio is expected in the fall of 2020.

FEI is considering various initiatives for the first CGIF portfolio, including:

- A project with the UBC School of Engineering and another partner, with the goal to develop a novel scalable and automated hydrogen-enriched natural gas (HENG) laboratory setup for conducting an integrated experimental study on the performance and feasibility of HENG - from injection, mixing quality, material exposure, separation and combustion, to emission;
- A feasibility and pilot study of a coupled anaerobic digester and pyrolyzer for co-processing organic waste to renewable natural gas and biochar (a charcoal-like carbon-rich solid);
- Several proposals that would create blue or green hydrogen: a catalytic converter to turn bioethanol into green hydrogen; a proton exchange membrane electrolyser; a process using electrochemistry to split mineral salt and water to generate hydrogen and hydroxide; a continuous reactor to convert waste polyethylene to hydrogen and carbon black using sulphur; and two pyrolysis-based initiatives that would generate hydrogen and carbon black from methane;
- Several initiatives related to carbon capture, including a tandem carbon recycling system for carbon capture and utilization from exhaust flue gas stream, a modular decarbonization system using membrane contractors, and a system that uses flue gas to cultivate microalgae in photobioreactors for capture and utilization; and
- Proposals that would create syngas from woody biomass, displacing the use of natural gas at lime kilns.

31.1 Please provide a description of what would be considered the preferred outcome such that it would 'maximize the potential of the CGIF'. What potential does FEI wish to maximize? What does FEI expect to use the outcomes for? Please explain.

Response:

As summarized on page 145 of the MRP Decision (Orders G-165-20 and G-166-20), the preferred outcomes and purpose of the CGIF are:

> … to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for customers. The Innovation Fund will assist FortisBC in addressing the expectation to reduce emissions, and forms part of FortisBC's proactive strategy to support the transition to a lower carbon economy, while maximizing the use of its energy delivery systems for its customers
>
> …
>
> The Innovation Fund is complimentary and incremental to FortisBC's innovative activities and is ultimately required to meet British Columbia's energy Objectives."

As noted in the preamble, the CGIF governance processes, including the CGIF selection criteria, are designed to maximize the potential of the CGIF by helping achieve the outcomes noted above. Please also refer to the response to CEC IR1 31.3.

31.2 When does FEI expect to have governance processes in place?

Response:

There are two primary components to the governance processes. The process by which portfolios will be approved has been implemented, while the process for the ongoing management of approved portfolios will be in place in late 2020.

31.3 Who is responsible for the first CGIF expenditure portfolio, and what are the criteria for approval?

Response:

As summarized in the MRP Decision[9], the approval process for CGIF expenditure portfolio involves three groups:

- The Innovation Working Group (comprising FortisBC employees) will identify, evaluate, select and execute the projects, track funds received and spent, report on progress and evaluate milestone achievements;
- The External Advisory Council (comprising external stakeholders drawn from interveners, academia, government and other relevant organizations) will provide insight and feedback on projects, review funding selections and provide recommendations to the Working Group for its investment decisions; and
- The Executive Steering Committee (comprising senior FortisBC employees) will provide strategic direction and approve portfolios

The five criteria for approval were also detailed during the MRP process[10]:

1. Amount of co-funding secured (from applicant and third parties)
2. Estimated CO2e reduction in British Columbia
3. Estimated non-CO2e emission reduction (NOx, SOx) in British Columbia
4. Estimation of energy cost reductions for customers
5. Relevant experience of the applicant project team

[9] BCUC Orders G-165-20 and G-166-20, p. 146.
[10] 2020-2024 MRP Application, Exhibit B-12, BCUC IR 2.218.3.

32. Reference: Exhibit B-2, page 181

> ***Average Speed of Answer***
>
> The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).
>
> The June 2020 year-to-date result of 41 seconds is consistent with prior years' results.
>
> For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.
>
> **Table 13-13: Average Speed of Answer**

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	34	37	40	34	35	39	41
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a

32.1 The speed of answer appears to have trended upward to 2016, then dropped in 2017 and is trending upward again. Did FEI make any changes in 2017 that affected its response time?

Response:

The absolute values of the annual variances in average speed of answer have been in the range of only three to six seconds. This range of variability would have a minimal impact on the overall customer experience and represents general stability in the metric.

The average speed of answer is influenced by numerous variables each year that affect the volume, duration and type of interactions supported by the contact centre. This includes the year-to-year changes in customer circumstances (including the varying impacts of weather on usage and bills), the introduction of new call types and queues, updated or new technology as well as the enhancement of self-service options for customers. Thus, while FEI introduced a mobile app in 2017 which may have had an impact on overall contact centre volumes (compared to what the result might otherwise have been), the use of the mobile app is only one of many variables that will affect the metric in any given year.

32.2 Has the speed of answer in 2020 been impacted by COVID-19?

Response:

While the full extent of the impact of COVID-19 is not yet known, as of June 2020, the average speed of answer for FEI has not been affected by COVID-19, as demonstrated by the fact that the year to date result is within two seconds of the annual result in 2019.