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December 10, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
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Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc.

2018 Fourth Quarter Gas Cost Report and Rate Changes Effective January 1, 2019 for the Mainland and Vancouver Island Service Area (the Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On November 23, 2018, FEI filed the Application referenced above. In accordance with BCUC Order G-230-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact Doug Richardson at 604-592-7643.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties in the FEI Annual Review for 2019 Rates proceeding
Ministry of Energy, Mines and Petroleum Resources

A. ENBRIDGE PIPELINE INCIDENT AND RISK TO SUPPLY

1.0 Reference: Exhibit B-1, p. 2

Risk to natural gas supply

On page 2, FEI submits that "the midstream costs for 2019 include materially higher forecast costs" are due to the T-South pipeline rupture.

FEI has published the following statement regarding the impact of the October 9 rupture of the Enbridge-owned natural gas transmission pipeline on FEI's natural gas supply:

> In the event of a prolonged period of colder than average weather, we could find ourselves in a position where demand is outpacing supply. If this imbalance extends over a number of days, it is possible that large-scale industrial and commercial customers would be faced with short-term curtailment.

In FEI's Rate Schedule 43 Streamlined Review, FEI stated:

> We've secured resources to get us back to a basically a --like we had 100 percent firm T-South for the year. We are back from a planning perspective, back to a kind of a normal planning scenario for us by incrementally buying that incremental gas at the Sumas delivery point.

1.1 Please confirm, or explain otherwise, that there is a significant risk to the natural gas supply as a result of the October 9 pipeline rupture that could result in customer curtailment.

Response:

During the period between October 9, 2018 and November 29, 2018, FEI believed there was a significant risk to the natural gas supply in the region, which could have resulted in customer curtailment. This was due to Enbridge's T-South capacity at Huntingdon being restricted between 17 percent and 68 percent of its normal operating pressure during that time frame. However, since that time period the risk has declined for the following reasons:

- On November 30, 2018, Enbridge released a shipper notice, expecting the capacity at Huntingdon would increase to approximately 1.4 Bcf/day, which is 85 percent of its normal operating pressure for the remainder of the winter period.[1] Physically, Enbridge

[1] On November 16, 2018, National Energy Board (NEB) issued an amending order (Order NB-001-2018) increasing Enbridge's 36-inch portion of the T-South pipeline to 85 percent of that segment's 60 day high pressure prior to the incident. On November 30, 2018, the NEB issued another amending order to increase the operating pressure restrictions on the 36-inch pipeline segment 9L2 between

began flowing approximately 1.4 Bcf/day to Huntingdon on December 4, 2018. This increase in capacity at Huntingdon compared to October and November levels was crucial, as the market enters what is typically the coldest months of the winter season (December and January).

- The relatively mild weather that the Lower Mainland, Oregon and Washington experienced in November allowed storage assets in the region to maintain reasonable inventory levels heading into December. If November was colder than normal, the region would have been forced to utilize storage assets at a higher than normal level. This could have resulted in low inventory levels which would have been a significant risk, given the T-South restrictions at Huntingdon would make it unlikely that the region could replenish storage in time to handle the next cold weather event.

Enbridge has scheduled dig and inline inspections periodically in December and January. This will cause T-South capacity at Huntingdon to be temporarily restricted to lower than 85 percent of its normal operating pressure. These inspections are not commonly scheduled in December and January; however, they must be completed now in order to get T-South pipeline capacity back to normal operating pressure in the near future. Therefore, there is still uncertainty and risk to the natural gas supply going forward, especially pending the outcome of Enbridge's dig and inline inspections scheduled in December and January. However, as laid out in this response, FEI believes that the previous level of significant risk to supply has declined.

1.1.1 If confirmed, in the view of FEI, would a higher natural gas rate mitigate the supply risk associated with the October 9 incident by encouraging conservation of gas? Please explain your view.

Response:

This response also addresses BCUC IRs 1.2.1, 1.2.1.1, and 1.2.1.1.1.

In FEI's view, it is possible that higher natural gas rates may encourage conservation of gas but FEI is uncertain to what extent and how quickly such an outcome might occur. As such, FEI is uncertain whether and how much of a higher natural gas rate would sufficiently impact natural gas demand in a short time frame to meaningfully reduce the risk of customer curtailment associated with the October 9 incident. In contrast, preliminary data with respect to FEI's actions

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Compressor Station 2 and the Huntingdon Meter Station.

to encourage customers to voluntarily conserve natural gas appear to indicate that these actions have induced a certain level of natural gas conservation already.

In the past, FEI has observed correlations between changes in annual demand and changes in customer rates over time. However, these observations cover periods of multiple years as opposed to the multiple months that are relevant for mitigating the risk of customer curtailment associated with the October 9 incident. FEI is aware that various research materials either conduct primary research or represent reviews of numerous third-party studies into price elasticity of natural gas customers. These studies indicate a range of elasticity values across a variety of regions, sectors, and study publication dates. Overall, FEI concludes from these studies that, over a 20-year time horizon, natural gas demand is relatively inelastic to natural gas prices, that natural gas demand should decline with increases in the natural gas price, and that elasticity has not changed materially over time.

In sum, FEI does not have the information that would be required to evaluate price elasticity across a period as short as multiple months. As such, FEI is not able to estimate what change in natural gas rates would be required to encourage customers to reduce demand to levels that would meaningfully reduce the risk of customer curtailment associated with the October 9 incident.

B. ALTERNATIVE RATE SETTING PERIOD

2.0 Reference: Exhibit B-1, p. 3; Tab 2, p. 7

Rate Comparison

Page 3 of the Application states, "The Storage and Transport Charges calculated under this alternative approach are based on using a 3-month rate setting period; the schedule at ALTERNATIVE Tab 2, Page 7 provides the flow-through calculations of the forecast costs for the January-March 2019 period."

On page 3 of the Application, FEI states that it recommends the 12-month rate setting period as opposed to the 3-month rate setting period.

2.1 In the view of FEI, is there a correlation between the change in natural gas rates and customer demand? In other words, what is the price elasticity of demand of natural gas rates for FEI's customers?

Response:

Please refer to the response to BCUC IR 1.1.1.1.

2.1.1 By FEI's best estimate, what change in natural gas rates, if any, would be required to encourage customers to reduce demand to levels that would meaningfully reduce the risk of customer curtailment on a short term basis?

Response:

Please refer to the response to BCUC IR 1.1.1.1.

2.1.1.1 What change in the Transportation and Storage rate would be required to achieve the level indicated in question 2.1.1 above.

Response:

Please refer to the response to BCUC IR 1.1.1.1.

2.2 Please re-calculate rates using a 6-month rate setting period. In doing so, please replicate ALTERNATIVE Tab 2, Page 7 to reflect flow-through calculations of forecast costs for the January-June 2019 period.

<u>Response:</u>

The Storage and Transport Charges are re-calculated using a 6-month rate-setting period as shown below.

BCUC IR 1.2.2 Response
ALTERNATIVE 6m
Tab 2
Page 7

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA
STORAGE AND TRANSPORT RELATED CHARGES FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST 6-MONTH PERIOD JAN 2019 TO JUN 2019
FIVE-DAY AVERAGE FORWARD PRICES - NOV 6, 7, 8, 9, AND 13, 2018

Line No.	Particulars	Unit	Residential RS-1	Commercial RS-2	Commercial RS-3	General Firm Service RS-5	NGV RS-6	*Subtotal*	Seasonal RS-4	General Interruptible RS-7	RS-1 to RS-7 Summary
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**MCRA Sales Quantity**	TJ	45,496.8	17,112.9	12,070.6	1,743.8	*19.7*	*76,443.7*	68.6	161.7	76,674.0
2											
3	**Load Factor Adjusted Quantity**										
4	Load Factor (a)	%	31.6%	31.5%	37.7%	45.6%	100.0%				
5	Load Factor Adjusted Quantity	TJ									
5	Load Factor Adjusted Volumetric Allocation	%	61.5%	23.1%	13.7%	1.7%	0.0%	100.0%			
6											
7											
8	**<u>MCRA Cost of Gas - Load Factor Adjusted Allocation</u>**										
9	**Midstream Cost of Gas Allocated by Rate Class**	$000	$ 82,217.7	$ 30,802.0	$ 18,337.1	$ 2,209.5	$ 13.0	$ 133,579.2			$ 133,579.2
10											
11											
12	**<u>MCRA Cost of Gas Unitized</u>**										
13	**MCRA Flow-Through Costs before MCRA deferral amortization**	$/GJ	$ 1.8071	$ 1.7999	$ 1.5192	$ 1.2670	$ 0.6607				
14											
15										Fixed Price	
16									Tariff	Option	
17	**<u>PROPOSED ALTERNATIVE January 1, 2019 Flow-through Storage and Transport Related Charges</u>**								Rate 5	Rate 5	
18			**RS-1**	**RS-2**	**RS-3**	**RS-5**	**RS-6**				
19	**Storage and Transport Flow-Through**		**$ 1.807**	**$ 1.800**	**$ 1.519**	**$ 1.267**	**$ 0.661**		**$ 1.267**	**$ 1.267**	
20	Existing Storage and Transport (effective Jan 1, 2018)		1.064	1.073	0.907	0.677	0.339		0.677	0.677	
21	Increase / (Decrease)	$/GJ	$ 0.743	$ 0.727	$ 0.612	$ 0.590	$ 0.322		$ 0.590	$ 0.590	
22	Increase / (Decrease)	%	69.83%	67.75%	67.48%	87.15%	94.99%		87.15%	87.15%	

Notes:
(a) Based on the historical 3-year (2015, 2016, and 2017 data) rolling average load factors for Rate Schedules 1, 2, 3 and 5.

Slight differences in totals due to rounding.

2.2.1 Please complete the below table for each rate schedule (RS-1, RS-2, RS-3, RS-5, RS-6) in order to compare existing Storage and Transport rates against rates based on a 3-month, 6-month and 12-month rate setting period.

	Rate Setting Period Used		
	3-Month	6-Month	12-Month
Rate			
Current Rate			
Inc. / (Dec.)			
% Inc. / (Dec.)			

Response:

The table below compares the Storage and Transport Charges using the three requested rate setting periods.

	Rate Setting Period Used		
Storage and Transport Charges	**3-Month**	**6-Month**	**12-Month**
RS-1			
Rate	$ 2.582	$ 1.807	$ 1.485
Current Rate	$ 1.064	$ 1.064	$ 1.064
$ Increase / (decrease)	$ 1.518	$ 0.743	$ 0.421
% Increase / (decrease)	142.7%	69.8%	39.6%
RS-2			
Rate	$ 2.556	$ 1.800	$ 1.490
Current Rate	$ 1.073	$ 1.073	$ 1.073
$ Increase / (decrease)	$ 1.483	$ 0.727	$ 0.417
% Increase / (decrease)	138.2%	67.8%	38.9%
RS-3			
Rate	$ 2.360	$ 1.519	$ 1.245
Current Rate	$ 0.907	$ 0.907	$ 0.907
$ Increase / (decrease)	$ 1.453	$ 0.612	$ 0.338
% Increase / (decrease)	160.2%	67.5%	37.3%
RS-5			
Rate	$ 2.034	$ 1.267	$ 1.029
Current Rate	$ 0.677	$ 0.677	$ 0.677
$ Increase / (decrease)	$ 1.357	$ 0.590	$ 0.352
% Increase / (decrease)	200.4%	87.1%	52.0%
RS-6			
Rate	$ 1.452	$ 0.661	$ 0.469
Current Rate	$ 0.339	$ 0.339	$ 0.339
$ Increase / (decrease)	$ 1.113	$ 0.322	$ 0.130
% Increase / (decrease)	328.3%	95.0%	38.3%

2.3 Please compare and contrast the pros and cons of a 3-month, 6-month and 12-month rate setting period as methods to reduce natural gas demand. As a part of your response, please elaborate on why FEI proposes the use of the 12-month rate setting period over the other alternatives.

Response:

As discussed in the response to BCUC IR 1.1.1.1, although in FEI's view it is possible that higher natural gas rates may encourage conservation of gas, FEI is uncertain to what extent and how quickly such an outcome might occur.

The rate comparisons and residential customer bill impacts provided in the responses to BCUC IRs 1.2.2.1 and 1.3.1 show that the bill impact differences, between the Storage and Transport Charges based on a 3-month, 6-month, and 12-month rate setting period, for the remaining winter period of January to March 2019 are not significant dollar amounts and may not be material enough in nature to drive decreased consumption from low volume consumers. And, as stated in the response to BCUC IR 1.1.1.1, preliminary data indicates that a certain level of natural gas conservation appears to be occurring with FEI's actions to encourage customers to voluntarily conserve natural gas. FEI is uncertain as to whether / how rates based on the 3-month or 6-month Storage and Transport Charges would affect customer behaviour – FEI has some concerns that higher rates, which may be perceived as penalizing consumption, may not work well with the voluntary conservation approach, and higher rates would be punitive to lower income customers who typically have few conservation options and are less able to pay the increased costs.

At this time, and under the current circumstances, FEI believes insufficient evidence exists to support the implementation of higher Storage and Transport Charges, based on either a 3-month or 6-month rate setting period, as a method to reduce natural gas demand.

Given the uncertainty around the potential for demand reduction from the shorter rate setting periods, FEI believes it is preferable to maintain the accepted 12-month rate setting period and avoid the anticipated rate volatility that would result from using either the 3-month or 6-month rate setting methods.

C. BILL IMPACT

3.0 Reference: Exhibit B-1, p. 3; ALTERNATIVE Tab 2, p. 7

Typical Customer Bill

Page 3 of the Application states, "Under a typical Mainland and Vancouver Island Rate Schedule 1 residential customer has an average consumption during the 3 months of January-March of 37 GJ – the bill impact of the higher alternative Storage and Transport rate compared to that set using the standard 12-month method for the January-March period equates to approximately $41."

3.1 Assuming a typical residential customer consumes 37 GJ over the period of January to March 2019, please calculate the total bill to be paid using a 3-month, 6-month and 12-month rate setting period.

Response:

The table below shows the total billed amounts for a typical residential customer consuming 37 GJ over the period of January to March 2019 based on a Storage and Transport charge determined using a 3-month, 6-month, and 12-month rate setting period.

Typical Residential Customer Jan to Mar Total Bill	Rate Setting Period Used 3-Month	 6-Month	 12-Month
January to March consumption 37GJ			
RS-1 Customer to Pay ($)	$ 462	$ 433	$ 422
$ increase to 12-Month rate	$ 41	$ 12	$ -
% increase to 12-Month rate	9.6%	2.8%	-