BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the Utilities Commission Act, R.S.B.C. 1996, c. 473

and

FortisBC Inc.

Application for a Certificate of Public Convenience and Necessity

for the Grand Forks Terminal Station Reliability Project

Final Submission of the ICG

May 7, 2019

A. Introduction

1) In the Application, FortisBC is seeking approval for a project to address reliability risks in the Grand Forks area (Project). The Project includes installing a second electric transformer at GFT and removing portions of 9L and 10L. The Project is scheduled to be completed and placed in-service over a three year period.

2) The Project is estimated to have a capital cost of approximately $13.171 million in as-spent dollars, with a rate impact of 0.26 percent. In the 2012-2013 Capital Expenditure Plan, FortisBC was seeking approval for $7.205 million to address the same reliability risks in the Grand Forks area.[1] Although the scope changes may account for the increased capital cost, the need for such scope changes suggests inadequate evidence and analysis by FortisBC in the 2012-2013 Capital Expenditure Plan.

B. Reliance on N-1 Criteria

3) The evidence in this proceeding is that service to the Grand Forks area has been and is reliable.[2] It is important to note that the need for the Project is not driven by customer concerns or reliability performance.

4) Service to the Grand Forks area has never met the single contingency (N-1) criteria, and yet FortisBC has advanced the Project because of a change in the assessment of reliability risks associated with the single contingency planning criteria. That is, FortisBC has concluded that service to the Grand Forks area should now meet the single contingency (N-1) criteria. So the applicability of the single contingency (N-1) criteria to service to the Grand Forks area is the first issue for the Commission Panel to consider.

5) In that regard, the Commission has previously approved the Mandatory Reliability Standard TPL-001-0.1, which directly addresses issues related to the applicability of the single contingency (N-1) criteria as follows:

[1] Exhibit B-2, BCUC IR 1.15.1
[2] Exhibit B-2, BCUC IR 1.3.7

> Planned or controlled interruption or electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems.[3]

6) The failure of GFT T1 will affect GFT only and not the reliability of the interconnected transmission system. In this regard, NERC has also considered reliability concepts[4], including the TPL-001, and has found:

> Therefore, the only customers whose service should be interrupted are those directly connected to the piece of equipment that failed or tripped. As long as we maintain Interconnection integrity, we do not expect our customers to lose service as a result of these very likely events.[5]
>
> But the brutal facts, as they say, are that utilities cannot afford to build or operate the Interconnection to avoid all risks. That generation and transmission systems are finite and limited and always will be.[6]
>
> We have always historically thought of our operating reliability criteria as being able to withstand an "n-1" event – that given some part of the Interconnection with "n" elements, we can reliably operate following the failure of one of them. But given the many different kinds of credible contingencies, "n-1" is not always correct. Rather, our reliability criteria should be based on being able to withstand the next credible contingency, which may not include multiple events.[7]

7) During this proceeding and in final submissions, FortisBC has identified reliability criteria as the primary driver of the "GFT Reliability Project".[8] What FortisBC has failed to adequately explain is the perceived need to now meet the single contingency planning criteria for service to the Grand Fork area, and the Company's changed assessment of the reliability risks.

8) FortisBC claims that it has applied the single contingency (N-1) criteria to service to the Grand Forks area for approximately 20 years. However, in the 2012-2013 Revenue Requirements application, FortisBC confirmed that it has recently considered service to the Grand Forks area to be a radial load as follows:

[3] Mandatory Reliability Standard TPL-001-0.1, footnote B to Table 1
[4] www.nerc.com/files/concepts_v1.0.2.pdf
[5] Ibid., p. 12
[6] Ibid, p. 14
[7] Ibid., p. 26
[8] FortisBC Final Submissions, p. 5, Part III

> As there is only one 161/63 kV transformer installed at the Grand Forks Terminal, a backup 63 kV source is provided via two 63 kV transmission lines which originate at the Warfield Terminal Station near Trail. This backup source is only used in the event that that T1 transformer is unavailable. Protection and communications limitations prevent the Grand Forks and Trail 63 kV from operating in parallel. As a consequence, the Grand Forks Terminal T1 transformer provides only a radial 63 kV supply to the area. If the transformer experiences a forced outage, then customers in the area will be without power....[9]

9) The ICG submits that nothing in that configuration has changed to cause FortisBC to now apply the N-1 criteria. Given the FortisBC reliance on the N-1 criteria to support this Project, the ICG submits that the Commission Panel should consider:

   a) whether service to the Grand Forks area should meet the single contingency (N-1) criteria; and
   b) whether service to the Grand Forks area meets the single contingency (N-1) criteria; and, if not,
   c) when and what investments should be made in new infrastructure (equipment) so that service to the Grand Forks area meets the N-1 criteria.

C. Reliance on Load Forecast

10) The second plank in the FortisBC effort to justify the Project is a load forecast with load growth. However, the load forecast filed in this proceeding should be compared to the load forecast filed in the 2012-13 Revenue Requirements proceeding. From the 2012-13 Revenue Requirements Application, the 2011 actual loads for winter and summer were provided[10] and the comparable winter and summer peak loads were filed in this proceeding.[11] The 2011 winter peak load was approximately 40 MVA and the 2018 winter peak load was approximately 31 MVA. The point to take from the load forecast evidence is that although FortisBC is forecasting increasing loads in order to justify the Project, the 2018 actual winter peak is lower than the 2011 actual winter peak, and only about 75% of the forecast peak. Moreover, the evidence regarding the 2018 winter peaks (quoted previously) of 31.22 MVA does not reconcile to the evidence regarding the 2018 winter peaks of 31.2 MW provided in other evidence.

[9] FortisBC 2012-13 Revenue Requirements Application, Exhibit B-1, Section 3.1.3 of the 2012-2013 Capital Expenditure Plan, p. 30
[10] 2012-13 Revenue Requirements Application., Exhibit B-9, Zellstoff Celgar, IR 2.18
[11] Exhibit B-12, ICG IR 2.11.1

Given this discrepancy in the evidence, the Commission cannot rely on either 2018 winter peak reported by FortisBC.

11) FortisBC has prioritized the Project "because the area's highest recorded seasonal peak loads (approximately 34 MVA in winter and 29 MVA in summer) have been above the backup supply capacity limitation (27 MW with a single line in service) several times in the past five years…"[12] So even with the introduction of the single contingency planning criteria, it is only during "seasonal peak loads" that service to the Grand Forks area has not met the single contingency planning criteria. Moreover, the average number of peak hours above 27 MW is not trending up. Although the summer peak in 2018 is higher than previous peaks, one data point does not establish a trend. The durations of not meeting the single contingency (N-1) criteria do not exceed what constitutes adequate reliability for a radial service.

12) In the event the Commission concludes that service to the Grand Forks area should meet the single contingency criteria, the ICG respectfully submits that approval of investments to meet the N-1 criteria should be delayed because the load forecast evidence in this proceeding does not justify the Project.

D. Consideration of Alternatives Identified by FortisBC

13) FortisBC dismissed the status quo "because FBC cannot currently meet the single contingency (N-1) transmission planning criteria in the event of a GFT T1 failure during seasonal peaks."[13] The ICG's view is that the status quo over the next five years should have been considered by FortisBC. During this period, a load management program could be implemented in order to reduce reliability risk from what is already a very low reliability risk.

14) The current 20-year load forecast indicates the Grand Forks area load will meet the single contingency criteria until 2031 when the demand load is forecast to reach 45 MW. Currently, FortisBC concerns relate to the backup supply capacity limitation of 27 MW (9L capacity) when the seasonal peak loads are approximately 34 MVA in winter and 29 MVA in summer. However, the number of hours that the seasonal peak

[12] FortisBC Final Submissions, p. 5, Part III, Section A
[13] FortisBC Final Submissions, para. 21

loads exceed the backup supply capacity limitation has not exceeded 20 hours in any peak season in the last five years.[14] It is only for those 20 hours that the capacity limitation is exceeded. That is, it is the risk of load loss for 20 hours that is the primary driver of this project. But for the reliability risk during 20 hours, the project could be delayed until at least 2031.

15) GFT T1, with a nominal rating of 45/60 MVA has sufficient capacity to meet the forecasted demand for the Grand Forks area over the system planning horizon of 20 years. The GFT T1 condition assessment concluded that the useful remaining life of the transformer is approximately 15 years. It is only in the event of the GFT T1 failure during the peak season loads that the Project is needed. As noted in FBC Final Submissions, the risk of failure of GFT T1 is 2.6 percent, just higher than an acceptable risk of failure of 2 percent. Again, the reliability risk until loads are considerably higher than current loads, is limited, and the ICG submits should be acceptable. Especially, when the cost of reducing this already small risk is approximately $13 million, which is the capital cost of FortisBC's preferred alternative.

E. Financial and Technical Considerations

16) FortisBC analyzed the financial impacts of the three alternatives and provided the total capital costs, and the PV of cost of service with rate impacts over a 40 year analysis period. FortisBC did not provide the NPV of cash flows.[15] The PV of 40 year cost of service ($2018) for each of Alternatives A, B and C are $9.959 million, $9.960 million, and $14.004 million, respectively.[16]

17) FortisBC concludes that Alternative C has the lowest initial capital but its PV of cost of service is highest because of higher O&M. And then relies on the PV of cost of service in its selection of Alternatives A and B over Alternative C. However, the FortisBC model reduces the PV of cost of service for Alternative A and B and does not reduce the PV of cost of service for Alternative C.[17] In response to an information

[14] Exhibit B-6, 1.7.3
[15] Exhibit B-2, BCUC IR 1.14.1
[16] Exhibit B-1, Section 3.4, p. 25-26, Table 3-3
[17] Exhibit B-5-3, Attachment 19.1 for Option A, B, and C, Tab O&M and Property Tax, Line 1

request[18], FortisBC calculates the reduction of O&M that would be necessary in order for the PV of cost of service of Alternative C to be the same as Alternatives B and C. It is reasonable to assume that the investments in 9L and 10L would result in O&M reductions. For that reason, the PV of cost of service evidence provided by FortisBC should not be accepted by the Commission.

18) The final selection of Alternative B over Alternative A turns on technical criteria because FortisBC believes Alternative B offers improved reliability over Alternative A. [19]

19) The technical benefits of Alternative B over Alternative A relate entirely to installing a second transformer at GFT. FortisBC claims that Alternative B offers improved reliability compared to Alternative A since it includes installation of a new second transformer at GFT as opposed to installation of the on-site spare, thereby addressing the existing condition of GFT T1.[20] FortisBC further claims that Alternative B is a more reliable option because OLI T1 would remain as an on-site spare at GFT. The benefits of Alternative B as compared to Alternative A turn on the condition assessment of GFT T1. In other words, Alternative B is only more reliable than Alternative A in the event of failure of GFT T1.

F. Conclusion

The ICG supports a status quo alternative for the next five years. The reliability risks and the load forecast do not yet justify the purchase of a second transformer at GFT. The purchase of a second transformer at GFT should be delayed until there is much stronger evidence that the reliability risks to service Grand Forks area loads are not acceptable.

[18] Exhibit B-2-1, Confidential ICG IR 2.2, Attachment 2.2
[19] FortisBC Final Submissions, para. 40
[20] Exhibit B-1, Section 3.5.1, p. 28