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Our File No.: 05497-264

May 21, 2019

BY ELECTRONIC FILING

British Columbia Utilities Commission
410 – 900 Howe Street
Vancouver, B.C. V6Z 2N3
Email: commission.secretary@bcuc.com

Attention: Patrick Wruck
Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Inc.
Project No. 1598987
Application for a Certificate of Public Convenience and Necessity for the Grand Forks Terminal Station Reliability Project – Final Submission

Enclosed please find the Reply Submission of FortisBC Inc., dated May 21, 2019 with respect to the above-noted matter.

Yours truly,

FARRIS, VAUGHAN, WILLS & MURPHY LLP

Per: JKY

Jason K. Yamashita

JKY/csh
c.c.: Registered Parties

FARRIS, VAUGHAN, WILLS & MURPHY LLP
Barristers • Solicitors Vancouver | Kelowna | Victoria

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

REPLY SUBMISSION OF FORTISBC INC.
MAY 21, 2019

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Attention: Jason K. Yamashita

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PART I - OVERVIEW

1. FortisBC Inc. (FBC or the Company) sets out below its reply to the intervener submissions delivered in this matter. Capitalized terms are used herein as defined in FBC's Final Submission dated April 23, 2019.

2. FBC continues to rely on its Final Submission and on its Application and evidence as a whole. Points that are not specifically responded to should not be taken to be admitted.

PART II - THE PROJECT IS NECESSARY

A. The single contingency (N-1) transmission system planning criteria apply in the Grand Forks area

3. ICG challenges the applicability of the single contingency (N-1) transmission system planning criteria to the Grand Forks area.[1]

4. The single contingency (N-1) transmission system planning criteria is the standard criteria used in the electric utility industry that is applicable to interconnected systems. In keeping with this standard utility practice, FBC applies the single contingency (N-1) transmission system planning criteria to all transmission elements that are part of the interconnected (but not radial) system.[2]

5. GFT is part of the interconnected system,[3] so it is not correct to say, as ICG does, that "[t]he failure of GFT T1 will affect GFT only and not the reliability of the interconnected transmission system".[4] ICG cites a NERC document in connection with this position. In its context, the third paragraph cited by ICG addresses the possibility that credible contingencies may include multiple related events (such as

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1 ICG Final Argument at para. 4.

2 Exhibit B-5 – FBC Response to CEC IR 1.14.1 at p. 26; Exhibit B-4 – FBC Response to BCOAPO IR 1.7.1 at p. 10.

3 Exhibit B-2 – FBC Response to BCUC IR 1.3.7 at pp. 21-22; Exhibit B-5 – FBC Response to CEC IR 1.5.1.1 at p. 8; Exhibit B-10 – FBC Response to BCOAPO IR 2.20.1 at p. 6

4 ICG Final Argument at para. 6.

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simultaneous failure of multiple elements that are physically or electrically related) as well as single events.[5] This is part of a discussion on how best to respond to contingencies and assumes that the single contingency (N-1) transmission system planning criteria apply; it should not be taken as undermining the criteria in any way. The third paragraph cited by ICG is misquoted as well as separated from its context. It does not end with "…which may not include multiple events" but instead states:[6]

> We have 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 any 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 <u>may include</u> multiple elements.
>
> (Emphasis added)

6. Moreover, the NERC document cited by ICG takes as its starting point the applicability of the single contingency (N-1) transmission system planning criteria to the interconnected system, stating:[7]

> Historically, we have planned and operated the Interconnections so that the next disturbance, event, or equipment failure that is likely to occur will not cause any area of the Interconnection to become unstable and lose its integrity, or cause generation or transmission equipment to operate outside its normal limits. These rules and principles comprise our *reliability criteria* for planning and operating the Interconnections, and these criteria, in turn, form the basis for our reliability standards.

7. The Grand Forks area is part of the interconnected system and is therefore subject to the single contingency (N-1) transmission system planning criteria. FBC's

[5] NERC, "Reliability Concepts" (version 1.0.2), online: <https://www.nerc.com/files/concepts_v1.0.2.pdf> at pp. 20-23.
[6] NERC, "Reliability Concepts" (version 1.0.2), online: <https://www.nerc.com/files/concepts_v1.0.2.pdf> at p. 26.
[7] NERC, "Reliability Concepts" (version 1.0.2), online: <https://www.nerc.com/files/concepts_v1.0.2.pdf> at p. 5.

practice in this regard accords with standard electrical utility criteria. ICG has advanced no valid argument or evidence for its contrary position.

B. FBC has consistently viewed the single contingency (N-1) transmission system planning criteria as applicable in the Grand Forks area

8. ICG claims that FBC's application of the single contingency (N-1) transmission system planning criteria in the Grand Forks area is a recent change. As its sole evidence to support this assertion, it points to a passage from FBC's 2012-2013 Revenue Requirements application in which FBC stated that because the backup source (9L/10L) is 63 kV and is prevented from operating in parallel, "…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…".[8]

9. ICG has misunderstood the quoted statement, which reflects that GFT T1 can only be relied on as a radial 63 kV supply because of the limitations of its backup supply. The existence of the 63 kV backup supply is explicitly recognized in the passage quoted by ICG at paragraph 8. The Grand Forks area is part of the interconnected system and is therefore subject to the single contingency (N-1) transmission system planning criteria.[9] As noted by FBC in response to an ICG IR, the single contingency (N-1) transmission system planning criteria have been applied to the Grand Forks area for at least 20 years.[10]

10. FBC's application in the 2012-2013 Revenue Requirements proceeding provides context which demonstrates that FBC has consistently viewed the single contingency (N-1) transmission system planning criteria as applicable in the Grand Forks area. The application states:[11]

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[8] ICG Final Argument at paras. 7-8.

[9] Exhibit B-5 – FBC Response to CEC IR 1.5.1.1 at p. 8; Exhibit B-10 – FBC Response to BCOAPO IR 2.20.1 at p. 6.

[10] Exhibit B-6 – FBC Response to ICG IR 1.7.1 at p. 27.

[11] FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Application, Exhibit B-1 – Application, Tab 6 (2012-2013 Capital Plan) at pp. 30-32.

> The Grand Forks Terminal is a major substation which provides the normal transmission supply for Grand Forks, Christina Lake and surrounding areas. The station is supplied at 161 kV both from Warfield (via the A.S. Mawdsley Terminal and from Oliver (via the Bentley Terminal) and thus has full single-contingency (N-1) reliability from a 161 kV bulk supply perspective…
>
> ….
>
> 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 T1 transformer is unavailable. Protection and communications limitations prevent the Grand Forks and Trail 63 kV systems 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 until the system can be manually reconfigured to use the backup 63 kV supply from Trail.
>
> ….
>
> A practical alternate solution would be to install a second 161/63 kV transformer T2 at the Grand Forks Terminal… Installation of this second transformer would provide the Grand Forks area 63 kV transmission system with both full N-1 reliability and sufficient capacity out to (and beyond) the planning horizon. Finally, the presence of the second transformer would remove the need to maintain a 63 kV backup supply from Warfield.
>
> (Emphasis added)

C. The Grand Forks area does not meet the single contingency (N-1) transmission system planning criteria

11. The Application and Final Submission establish that the Grand Forks area does not meet the single contingency (N-1) transmission system planning criteria. It is not possible to partially satisfy the criteria.

12. BCOAPO agrees that the need for the project is driven by the inability of the 63kV system in the Grand Forks area to meet the N-1 contingency planning criteria, as required by FBC's standards for an interconnected system.[12] BCOAPO also states

[12] BCOAPO Final Argument at p.5.

that FBC has adequately demonstrated that existing facilities are inadequate to meet the single contingency (N-1) transmission system planning criteria in the Grand Forks area.[13]

13. CEC submits that there is a significant need for the Project given the lack of N-1 redundancy and the poor condition of the existing equipment.[14]

14. However, ICG states that "[t]he 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".[15]

15. ICG's statement is incorrect. The Grand Forks area <u>currently</u> does not meet the single contingency (N-1) transmission system planning criteria. The single contingency (N-1) transmission system planning criteria requires that the system is capable of meeting the area load at all times.. As discussed in the Application, maximum peak load levels in the Grand Forks area in recent years, approximately 34 MW,[16] exceed the backup transmission capability of 27 MW. The backup transmission lines 9L and 10L cannot reliably operate in parallel to supply 45 MW.[17]

16. Intervener arguments regarding load growth are addressed below.

PART III - PROJECT DEFERRAL WOULD LEAD TO INCREASED RISKS IN THE GRAND FORKS AREA

17. ICG seeks to delay the Project for five years or more.[18] CEC recommends Commission approval of the Project but states that it would not object to its deferral.[19]

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[13] BCOAPO Final Argument at p. 6;
[14] CEC Final Argument at para. 44.
[15] ICG Final Argument at para. 14.
[16] Exhibit B-1 – Application at p. 12
[17] Exhibit B-1 – Application at pp. 13-14.
[18] ICG Final Argument at paras. 12-13 and Conclusion.
[19] CEC Final Argument at paras. 44-47, 96.

A. Risks of delaying the Project

18. Deferral of the Project is not acceptable because the Grand Forks area does not meet the single contingency (N-1) transmission planning criteria. As noted in the Application, there is a significant reliability concern for the Grand Forks Area due to poor condition of existing facilities, which may result in extended outages to customers during peak load conditions.[20] CEC acknowledges that deferral of the Project would increase risks.[21]

19. These risks are thoroughly outlined in the Application and FBC's Final Submission: reliability risks arise from the limited ability of the backup supply to the Grand Forks area (9L/10L) and from the poor condition of existing facilities (particularly 9L/10L, though GFT T1 and OLI T1 also have issues).[22]

20. FBC submits that the Project cannot be deferred further as the reliability risks identified will worsen if it is delayed.

B. The condition of existing facilities has deteriorated since 2012-2013

21. FBC has maximized the value of its assets by undertaking appropriate maintenance and improvements. This has included changing the load tap changer tanks and performing recommended maintenance on GFT T1[23] and completing urgent work and rehabilitation upgrades on portions of 9L and 10L.[24]

22. Despite these efforts, the condition of facilities has continued to deteriorate. Transmission lines 9L and 10L are in very poor condition, increasing reliability risks.[25] 10L has been de-energized since 2010 due to its condition.[26] As BCOAPO notes, 9L and 10L have experienced almost three times the number of outages

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[20] Exhibit B-1 – Application at pp. 3, 20.
[21] CEC Final Argument at para. 46.
[22] Exhibit B-1 – Application at pp. 14-20; FBC Final Submission at paras. 14-19.
[23] Exhibit B-2 – FBC Response to BCUC IR 1.1.1, 1.2.2, 1.2.4 at pp. 4, 8, 10.
[24] Exhibit B-1 – Application, Confidential Appendix C (9L/10L Condition Assessment) at pp. 4-7.
[25] Exhibit B-1 – Application at pp. 16-19 and Confidential Appendix C (9L/10L Condition Assessment) at pp. 5-7.
[26] Exhibit B-2 – FBC Response to BCUC IR 1.1.1 at p. 2.

experienced on average by FBC's other 63 kV lines.[27] Transformer GFT T1 has continued to age and is approaching end-of-life, while OLI T1 has also continued to age though it is normally de-energized.[28] The Project should proceed without delay.

C. FBC has appropriately identified and quantified Project risks

23. CEC submits that quantification of risk reduction would or could be useful.[29]

24. FBC appropriately identified risks and engaged in comparative analysis of relative risks. For example, FBC noted that schedule risk is lowest for Alternative A because OLI T1 is already on site, while Alternative B is dependent on the lead time for procurement of a new transformer, and Alternative C has a greater likelihood of being impacted by season construction windows. FBC engaged in a similar comparison of other risks in its Application.[30]

25. FBC's filed evidence includes quantification of impact costs ($) and schedule risks (days) as well as expected monetary value ($) and schedule risks (days) associated with various identified risks.[31]

PART IV - LOAD GROWTH IS NOT ONE OF THE DRIVERS FOR THE PROJECT

A. ICG's position on load growth should not be accepted

26. ICG characterizes load growth as one of the planks used by FBC to justify the Project.[32]

27. However, load growth is not one of the drivers for the Project. Instead, the Project is driven by the need to meet single contingency (N-1) transmission planning

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[27] BCOAPO Final Argument at p. 4.
[28] Exhibit B-1 – Application at pp. 15-16 and Appendix B (ABB Assessment of GFT T1) at pp. 17-19.
[29] CEC Final Argument at paras. 42, 55-56.
[30] Exhibit B-1 – Application at pp. 27-28.
[31] Exhibit B-2 – FBC Response to BCUC IR 1.9.1 at pp. 41-42 and Confidential Attachment 1.9.1.
[32] ICG Final Argument at para. 10.

criteria for the 63 kV system at existing load levels and to address issues with the condition of equipment. As noted in the Application, GFT T1 has sufficient capacity to meet the forecast distribution demand for the Grand Forks area load over the system planning horizon of 20 years.[33] FBC evidence in its 2012-2013 Revenue Requirements application also confirmed that load growth is not a driver for the Project.[34]

28. Load growth is relevant to this matter as a factor in comparing the alternatives. Alternatives A and B provide the same capability to meet forecast load growth in the Grand Forks area over the 20-year planning horizon. Alternative C does not.[35]

29. ICG also alleges an inconsistency in FBC evidence on 2018 winter peak loads.[36]

30. FBC evidence includes a 2018 winter peak of 31,218.22 kVA.[37] This figure was rounded to 31.22 MVA in an IR response.[38] The 2018 winter peak was also quoted as 31.2 MW in response to another IR.[39] Since the power factor was close to unity and the data was only provided for a single day, the 2018 winter peak was approximated as "MW" and rounded to a single decimal point. This reflects the following formula:

Real Power (MW) = Power Factor x Apparent Power (MVA)

31. ICG's assertion that "the number of hours that the seasonal peak loads exceed the backup supply capacity limitation has not exceeded 20 hours in any peak season in the last five years"[40] is mistaken. The 20 hours referenced by ICG was the total number of hours GFT T1 load was above 27 MW on January 5, 2017, the day of

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33 Exhibit B-1 – Application at p. 12. See also Exhibit B-12 – FBC Response to ICG IR 2.13.2 at p. 16.
34 FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Application, Exhibit B-9 – FBC Response to Zellstoff Celgar Limited Partnership (Celgar) IR 2.18.2 at p. 36.
35 Exhibit B-4 – FBC Response to BCOAPO IR 1.3.1 at p. 3.
36 ICG Final Argument at para. 10.
37 Exhibit B-5 – FBC Response to CEC IR 1.7.1 at p. 11, Attachment 1.7.1.
38 Exhibit B-12 – FBC Response to ICG IR 2.11.1 at p. 13.
39 Exhibit B-6 – FBC Response to ICG IR 1.7.3 at pp. 27-28.
40 ICG Final Argument at para. 14.

the Winter 2016-2017 peak.[41] The total number of hours GFT T1 load was above the capacity limitation of 27 MW was much larger, as is illustrated by the graphs of GFT T1 winter load duration curves filed by FBC.[42] Precise comparisons to the backup supply capacity limitation are made difficult because the graphs are illustrated in kVA and it may not be appropriate to assume the power factor is unity over an entire season. As a broad indicator, however, the graph for the 2016-2017 winter load duration curve shows GFT T1 loads in excess of 27 MVA (which, again, might not equal 27 MW over an entire season) for approximately 400 hours or more, and the graph for the 2017-2018 winter load duration curve shows loads in excess of 27 MVA for approximately 200 hours.

32. Further, a risk of load loss for 20 hours at a time should not be minimized, as ICG attempts to do.[43] For many residential customers, this is not an acceptable amount of time to potentially lose service, particularly in winter. For industrial customers, such as those ICG claims to represent, even a brief loss of service could impose significant costs.

B. Load management would not address the issues identified in the Application

33. ICG submits in support of a five-year delay of the Project that a load management program would reduce reliability risk.[44] ICG points to no evidence that a load management program could do so in the circumstances.

34. On March 25, 2019, after FBC responded to two rounds of IRs in this proceeding, ICG filed a letter confirming that it did not intend to file evidence in this proceeding. In the same letter, ICG requested new information from FBC, effectively seeking a third round of IRs.[45]

[41] Exhibit B-6 – FBC Response to ICG IR 1.7.3 at pp. 27-28.
[42] Exhibit B-12 – FBC Response to ICG IR 2.14.1 at pp. 17-22.
[43] ICG Final Argument at para. 14.
[44] ICG Final Argument at para. 13.
[45] Exhibit C-4-6 – ICG letter dated March 25, 2019.

35. In a further letter filed on April 1, 2019, ICG explained that the new information it sought to request was "necessary to consider options that relate to load management and the possibility of delaying the upgrades beyond the project schedule proposed by FortisBC".[46]

36. In response, FBC filed a submission on process arguing that the Commission should not grant ICG's request for further IRs because ICG had raised the issue of load management late in the proceeding and the evidence on the record does not support the premise that load management is a reasonable alternative to avoid or delay the Project.[47] The FBC submission demonstrated that demand side management (DSM) cannot feasibly address reliability concerns in the Grand Forks area because the amount of load reduction required is very substantial in relation to the total area load. The other load management approach, load curtailment, is a temporary emergency measure not appropriate to use for system planning purposes.

37. By Order G-77-19, the BCUC denied ICG's request for additional IRs. Its Reasons for Decision noted that "[a]t this stage of the proceeding, the Panel is not persuaded that the responses to ICG's questions would materially add to its understanding of the issues in this proceeding."

38. FBC submits that it has demonstrated in its Submission on Further Process that load management is not a feasible option for addressing the issues identified in the Application, and there is no evidence that supports ICG's position. BCOAPO agrees that load management is not feasible in the circumstances.[48]

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[46] Exhibit C-4-6-1 – ICG letter dated April 1, 2019.
[47] Exhibit B-14 – FBC Submission on Further Process.
[48] BCOAPO Final Argument at p. 9.

PART V - TECHNICAL AND FINANCIAL ISSUES RAISED BY INTERVENERS ARE PROPERLY ADDRESSED

A. GFT T1 rate of failure and lifespan

39. CEC argues that the 2.6% GFT T1 rate of failure estimated by ABB may be high and should be discounted to below 2%.[49]

40. ABB's estimate was based on the best information available to it and should be accepted. It should not be discounted based on speculation and in the absence of contrary evidence. ABB stated:[50]

> The results above indicate a high risk of failure (2.6) for this transformer based on the current DGA in oil and available test and maintenance data. The below figure shows the Risk of Failure (RoF) compared to a transmission utility population. It can be seen that RoF is on the high side for this unit.

41. ABB's estimated 2.600% risk of failure is based on the condition of the transformer as is, recognizing the observed presence of acetylene (C2H2) and assuming no inhibitor in oil. The alternative 0.524% estimate provided by ABB is based only on speculation that acetylene (C2H2) concentrations measured since load tap changer tube replacement in October 2014 may be from residual acetylene in the insulations.[51] The ABB report notes measurements of 33 ppm to 54 ppm in the years since and cautions that "[n]ormally a level of 46 ppm Acetylene corresponds to an unacceptable high probability of failure."[52]

42. ABB goes on to conclude:[53]

> The calculated risk of failure for this transformer is 2.6 based on the current [dissolved gas assessment] in oil and available test and maintenance data. This [rate of failure] is on the high side for this unit when compared to a typical utility population.

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[49] CEC Final Argument at paras. 26-28.
[50] Exhibit B-1 – Application, Appendix B (ABB Assessment of GFT T1) at p. 17.
[51] Exhibit B-1 – Application, Appendix B (ABB Assessment of GFT T1) at p. 17.
[52] Exhibit B-1 – Application, Appendix B (ABB Assessment of GFT T1) at pp. 7-8.
[53] Exhibit B-1 – Application, Appendix B (ABB Assessment of GFT T1) at p. 19.

> It is to be noted that in CIGRE Reliability Survey 642 (A2.37), the 2nd most failed component was the load tap changer and the single most cause of failure is inadequate short circuit strength based on the Transformer Industry-Wide Database (IDB). Both of these components are weak in this unit. Also, based on the age profile for over 7,000 units in a particular subset of in-service transformers contained in the IDB, the most common end of life for a transformer seems to occur in the 35 to 45 year age bracket. This unit is 53 years old. With each passing year, the probability of failure on this unit increases.

43. FBC has operated the GFT T1 load tap changer manually since April 2016, which appears to have resulted in stable dissolved hydrocarbon and hydrogen gases. However, the load tap changer may not be the actual cause of the high acetylene levels observed.[54] Since the hydrocarbon gases and hydrogen signature/ratio appear to have remained constant since 2002, FBC assumes that replacement of the load tap changer diverter tubes did not solve the underlying issues causing the acetylene generation.[55]

44. CEC also argues that FBC's use in its financial assessment of a 10-year lifespan for GFT T1 is very conservative and submits that the 15-year lifespan estimated by ABB is more appropriate.[56]

45. While ABB recommended against keeping GFT T1 in service more than 15 years, FBC considered a 10-year lifespan to be the most appropriate given that the transformer is 53 years old, exceeding the expected transformer lifespan of 40 years, and the cause of the abnormal fault gases has not been determined.[57]

46. The financial schedules for all three alternatives assume replacement of GFT T1 after 10 years. If replacement was instead assumed to be after 15 years, the impact of the change would be the same for all three alternatives. This would result in an equivalent decrease in present value of the cost of service.

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[54] Exhibit B-2 – FBC Response to BCUC IR 1.2.2 at p. 8.
[55] Exhibit B-5 – FBC Response to CEC IR 1.8.1 at p. 13.
[56] CEC Final Argument at paras. 59-60.
[57] Exhibit B-2 – FBC Response to BCUC IR 1.2.5 at p. 11.

B. O&M costs of alternatives were properly addressed

47. ICG claims that the FBC model for comparison of the alternatives reduces the present value of cost of service for Alternatives A and B but does not do so for Alternative C on the basis that "[i]t is reasonable to assume that the investments in 9L and 10L would result in O&M reductions".[58]

48. The ICG argument is based on its assumption that Alternative C should result in an O&M reduction which should be included in the cost of service calculation. ICG has not identified any evidence that would support this assumption. Its position on this point should not be accepted.

49. Alternative C does have the lowest capital cost, but will require the same level of O&M that is being incurred today because of the ongoing need for brushing and annual patrols of the rehabilitated transmission lines. The capital investment proposed in Alternative C does not have any incremental benefit or cost from existing O&M, so as a result no incremental O&M benefit or cost was included in the cost of service calculation. However, FBC in its alternatives evaluation analysis for Alternative C did reduce the annual capital costs for urgent repairs by $97 thousand (2018$).[59]

50. Alternatives A and B would each result in an incremental reduction in O&M expenses relating to the portion of the 9L and 10L lines being removed. This incremental O&M benefit was included in the cost of service calculation.

51. FBC explained in the Application that it expects the removal of 9L and 10L will reduce transmission line O&M expenditures by approximately $60 thousand per year and reduce brushing costs by an average of $31 thousand per year. This applies equally to Alternatives A and B. (For Alternatives A and B, incremental costs required to maintain a second transformer at GFT were estimated to be $5

[58] ICG Final Argument at para. 17.
[59] Exhibit B-1 – Application, p. 23.

thousand per year).[60] FBC filed evidence sets out that the transmission line savings were assumed while the vegetation savings were determined using estimates from contractors in coordination with historical costs over the past 10 years.[61]

52. In addition, FBC filed confidential evidence identifying the amount of reduction in annual maintenance costs associated with Alternative C which would be needed to result in Alternative C having the lowest present value cost alternative.[62]

C. Changes in scope of Project

53. ICG alleges that while the Project's changed scope accounts for its increased capital cost relative to the figure of $7.205 million noted in FBC's 2012-2013 Capital Expenditure Plan, the need for such scope changes suggest inadequate evidence and analysis by FBC.[63]

54. FBC filed its 2012-2013 Capital Expenditure Plan in June 2011. The approval for $7.205 million sought at that time related only to relocation and storage of OLI T1 and construction of the fibre optic link between Grand Forks and Warfield. As noted in FBC's evidence, approval for expenditures related to the installation of the second transformer, as well as the salvage costs for 9L and 10L, were not included in the 2012-2013 Capital Expenditure Plan application and were proposed to be included in the 2014-2015 Capital Expenditure Plan application.[64] The Project's cost is consistent with estimates previously filed by FBC with the Commission.[65]

55. FBC's prior filings with regard to the Project were appropriate to reasonably foreseeable circumstances at the time they were filed.

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[60] Exhibit B-1 – Application at pp. 22, 42 and Appendix J.
[61] Exhibit B-5 – FBC Response to CEC IR 1.24.1 at p. 47.
[62] Exhibit B-12-1 – FBC Response to ICG Confidential IR 2.2.2 at p. 3.
[63] ICG Final Argument at para. 2.
[64] Exhibit B-2 – FBC Response to BCUC IR 1.15.1 at p. 56.
[65] Exhibit B-2 – FBC Response to BCUC IR 1.15.2 at pp. 56-57.

PART VI - CONCLUSION

56. In light of all the above, FBC reaffirms its request that a CPCN be granted to pursue the GFT Reliability Project as described in the Application and FBC's Final Submission.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Counsel for FortisBC Inc.:

[Original signed by Jason K Yamashita]____
Jason K. Yamashita

Dated: May 21, 2019