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FARRIS

File No: 05497-0293

September 26, 2023

BY EMAIL

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: In the Matter of the *Utilities Commission Act*, RSBC 1996, c 473 and FortisBC Inc.'s Application for a Certificate of Public Convenience and Necessity for the A.S. Mawdsley Terminal Station Project**

Enclosed please find the Final Submission and Book of Authorities of FortisBC Inc. dated September 26, 2023 with respect to the above-noted matter.

Yours truly,

FARRIS LLP

Per: E Miller

Erica C. Miller

ECM/gc
Enclosures
c.c.: Registered Parties



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**BRITISH COLUMBIA UTILITIES COMMISSION**

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

and

FortisBC Inc.'s Application for a Certificate of Public Convenience and Necessity
for the A.S. Mawdsley Terminal Station Project

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# FINAL ARGUMENT OF FORTISBC INC.

**SEPTEMBER 26, 2023**

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**FortisBC Inc.**

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## PART 1 - OVERVIEW

1. On February 24, 2023, FortisBC Inc. (**FBC** or the **Company**) filed an application (the **Application**) with the British Columbia Utilities Commission (**BCUC**) for a Certificate of Public Convenience and Necessity (**CPCN**) for the A.S. Mawdsley (**ASM**) Terminal Station Project (the **ASM Project** or the **Project**).[1]

2. In the Application, FBC seeks approval to install two new 150 MVA 63/161 kV transformers at the Warfield Terminal Station (**WTS**), carry out related station and transmission modifications, and decommission the existing ASM Terminal Station.[2] The need for the ASM Project is driven by load growth in the Boundary and Similkameen areas, which has resulted in the inability for FBC to meet the applicable criteria (N-1, single contingency) in its Transmission System Planning Criteria, triggering potential reliability issues. Project need is also driven by the deteriorating condition of the two power transformers that are currently installed at the ASM Terminal Station (**ASM T1** and **ASM T2** or together, the **ASM Transformers**).[3]

3. The estimated total cost of the Project is $35.179 million in as-spent dollars, which is estimated to result in a levelized rate impact of 0.63 percent.[4]

4. On March 30, 2023, pursuant to Order G-70-23, the BCUC established a written public hearing process and a regulatory timeline for the Application.[5]

5. Several interveners participated in this proceeding: British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, and Tenant Resource & Advisory Centre (together, **BCOAPO**), Commercial Energy Consumers Association of British Columbia (**CEC**), Industrial Customers Group (**ICG**) and Mr. Murray McConnachie.[6]

1 See Ex. B-1, Application.
2 Ex. B-1, Application, p. 1 and Appendix J-2, Draft Final Order.
3 Ex. B-1, Application, pp. 1 and 10.
4 Ex. B-1, Application, pp. 4.
5 Order G-70-23 p. 2 and Appendix A.
6 Mr. Alan Wait's application to intervene was also accepted by the BCUC, though he withdrew from the proceeding (see Ex. C2-2).

6. The written record in this proceeding is comprehensive. FBC filed a detailed Application,[7] and this evidence has been supplemented through FBC's responses to over 500 Information Requests (**IRs**), which were provided over two rounds by the BCUC and interveners.

7. The evidentiary record confirms that the orders the Company seek should be granted.[8] A draft final order is included as Appendix J-2 of the Application.

8. While this Final Submission summarizes key points, the Company relies on the evidentiary record as a whole in support of its Application.

## PART 2 - THE APPLICABLE STATUTORY FRAMEWORK

9. In the Application, FBC seeks a CPCN pursuant to sections 45 and 46 of the *Utilities Commission Act*, RSBC 1996, c 473 (the **UCA**).

10. The Company has applied to the BCUC for a CPCN as the ASM Project involves a system extension, and the total capital cost[9] of the Project is forecast to exceed FBC's $20 million threshold for CPCN applications.[10]

### A. THE PROJECT IS IN THE PUBLIC CONVENIENCE AND NECESSITY

11. Pursuant to section 45 of the UCA, FBC may not begin the construction or operation of an extension of a public utility plant or system, without first obtaining a CPCN from the BCUC. For the BCUC to grant a CPCN, it must be satisfied that the project is "necessary for the public convenience" and "properly conserves the public interest". The BCUC and the Supreme Court of Canada have described the test for approval of a CPCN as being whether the project is in the "public convenience and necessity".[11]

12. The UCA itself does not provide a definition or further explanation on when a project will be in the "public convenience and necessity". Instead, the BCUC has a broad discretion to consider a variety of factors and evidence and has held that the test of what constitutes

[7] See Ex. B-1, Application with Appendices and Ex. B-1-1 with Confidential Appendices.
[8] See Ex. B-1, Application, Appendix J-2, Draft Final Order.
[9] The total capital cost of the ASM Project is forecast to be approximately $35.179 million in as-spent dollars (Ex. B-1, Application, p. 55).
[10] Ex. B-7, FBC Response to CEC IR1 1.2.
[11] See Order and Decision C-4-06, British Columbia Transmission Corporation's Application for a CPCN for the Vancouver Island Transmission Reinforcement Project (July 7, 2006), p. 11 and citing *Memorial Gardens Assn. (Can.) Ltd. V. Colwood Cemetery Co*., [1958] S.C.R. 353, para. 9.

public convenience and necessity is a "flexible test" where the BCUC is able to consider and weigh a "broad range of interests".[12]

13. While the relevant factors to consider under sections 45 and 46 of the UCA will vary with each application, in the circumstances of the ASM Project, FBC submits that the key considerations include: (a) the need for FBC to satisfy the applicable N-1 Transmission System Planning Criteria and be able to continue to serve all load in the event of an outage or failure of one of the ASM Transformers, including as customer load continues to grow in the future, (b) the need to replace aged infrastructure that is in deteriorating condition and increasingly susceptible to failure, (c) ensuring the reliability of FBC's system, (d) alignment with the applicable British Columbia energy objectives, (e) consistency with FBC's most recent Long Term Electric Resource Plan, (f) the cost-effectiveness of the Project (g) the rate impact of the Project, and (h) the public consultation and engagement with Indigenous Communities undertaken.

14. As is discussed in more detail in this Argument, FBC submits that the BCUC should determine that the ASM Project is in the public interest and necessity and that a CPCN should be granted.

## B. <u>SECTION 46(3.1) OF THE UCA</u>

15. In addition, section 46(3.1) of the UCA requires the BCUC to consider the following when deciding whether to issue a CPCN: (a) the "applicable of British Columbia's energy objectives", (b) "the most recent long-term resource plan filed by the public utility under section 44.1, if any", and (c) the extent to which the application is consistent with sections 6 and 19 of the *Clean Energy Act*, SBC 2010, c 22 (**CEA**).

### 1. <u>Section 46(3.1)(a) – Energy Objectives</u>

16. BC's energy objectives are set out in section 2 of the CEA. FBC was mindful of these objectives when designing the ASM Project, and identified the ASM Project as being aligned with or advancing the following objectives in the CEA:

   a. generating at least 93% of the electricity in BC from clean or renewable resources and building the infrastructure necessary to transmit that electricity (CEA, s. 2(c));

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[12] Order and Decision C-4-06, *supra,* p. 15.

b. reducing BC greenhouse gas (**GHG**) emissions in accordance with certain targets (CEA, s. 2(g));

c. encouraging the switching from one kind of energy source or use to another that decreases GHG emissions in BC (CEA, s. 2(h));

d. encouraging economic development and the creation and retention of jobs (CEA, s. 2(k)); and

e. maximizing the value, including the incremental value, of the resources being clean or renewable resources, of BC's generation and transmission assets for the benefit of BC (CEA, s. 2(m)).[13]

17. The ASM Project does not conflict with the remaining energy objectives set out in section 2 of the CEA, and it does not hamper the advancement of these objectives.[14] For additional information on the impact of the ASM Project on each of the energy objectives set out in section 2 of the CEA, see Table 9-1 of the Application.[15]

### 2. Section 46(3.1)(b) – Long Term Electric Resource Plan

18. With respect to the requirement in section 46(3.1)(b) of the UCA for the BCUC to consider the most recent long-term resource plan filed by the public utility, the ASM Project was identified by FBC in section 6.4 of its last Long Term Electric Resource Plan, filed on August 4, 2021 (the **2021 LTERP**) and accepted by the BCUC in Order G-380-22. In the 2021 LTERP, the ASM Project was identified as two separate projects, with ASM T1 being replaced in 2024/2025 and ASM T2 being replaced in 2028/2029. Since the filing of the 2021 LTERP, FBC has identified that both ASM Transformers need to be upgraded to higher MVA transformers within a three-year window, as is discussed in Part 3 below on Project Need.[16]

### 3. Section 46(3.1)(c) – Sections 6 and 19 of the CEA

19. Finally, with respect to consistency with the objectives set out in sections 6 and 19 of the CEA, these provisions are not applicable to the ASM Project, as the Project does not involve

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13 Ex. B-1, Application, pp. 71-72.
14 Ex. B-1, Application, pp. 71-72.
15 Ex. B-1, Application, pp. 71-72.
16 Ex. B-1, Application, p. 72.

the construction or extension of generation facilities, and FBC is not a "prescribed public utility".[17]

## PART 3 – PROJECT NEED

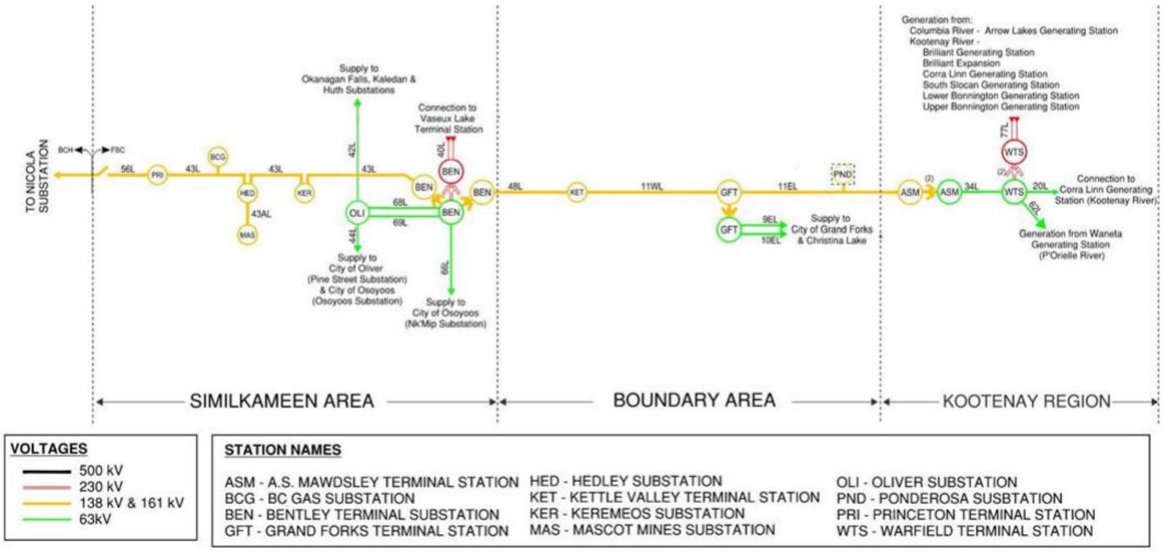
20. As is set out in more detail in this Part, the need for the ASM Project is driven by the fact that load growth in the Boundary and Similkameen areas has resulted in a situation where FBC is unable to meet its Transmission System Planning Criteria. In the event of an outage of one of the two ASM Transformers (an N-1 contingency event), FBC will be unable to reliably maintain service to the Boundary and Similkameen areas during peak periods. This risk is exacerbated by a second driver of Project need: the age and condition of the ASM Transformers, which have each been identified as having a "high risk of failure" and as requiring immediate attention.[18]

### A. SYSTEM OVERVIEW

21. The Boundary and Similkameen areas of FBC's service area are located in the Southern Interior of British Columbia and cover a large geographical area. FBC has over 27,000 direct customers in these areas, which account for approximately 19% of FBC's total summer and winter peak load.[19]

22. Customers in the Boundary and Similkameen areas are supplied by power generated in the Kootenay region, as well as power from a transmission interconnection to BC Hydro's Vaseux Lake (**VAS**) Terminal Station, as shown by the following single line diagram:[20]

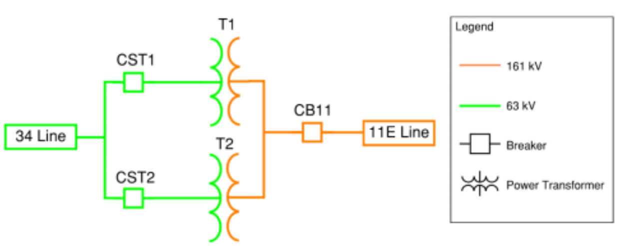
[17] Ex. B-1, Application, p. 73.
[18] Ex. B-1, Application, pp. 1 and 10.
[19] Ex. B-1, Application, pp. 10 and 13; Ex. B-8, FBC Response to ICG IR1 1.1.
[20] Ex. B-1, Application, pp. 11-12, Figure 12, as updated in Ex. B-13, FBC Response to BCOAPO IR2 26.1.




23. As depicted above, the power generated in the Kootenay region flows to the Boundary and Similkameen areas first via WTS (in Trail, BC), where it is converted from 230 kV to 63 kV by the two current WTS transformers (**WTS T1** and **WTS T2**) before travelling on 34 Line to the ASM Terminal Station, approximately 1km away. At the ASM Terminal Station, the power is transformed from 63 kV to 161 kV by the ASM Transformers and supplied to the 11E Line into the Boundary area and ultimately onwards to the Similkameen area.[21]

24. The two ASM Transformers were manufactured in 1965 (ASM T1) and 1971 (ASM T2) and have been in service for 57 and 51 years, respectively. They have a combined capacity of 160 MVA (or 80 MVA per transformer).[22] As is described in more detail below under the heading "The Condition of the ASM Transformers", the ASM Transformers are in deteriorating condition and require immediate attention.

25. A single line diagram of the configuration of the ASM Terminal Station is as follows, and uses a radial bus configuration:[23]




[21] Ex. B-1, Application, p. 12.
[22] Ex. B-1, Application, p. 14.
[23] Ex. B-1, Application, p. 15, Figure 3-5.

## B. INABILITY TO MAINTAIN RELIABILITY AND MEET LOAD GROWTH

### 1. FBC's Transmission System Planning Criteria

26. FBC's Transmission System Planning Criteria, which are consistent with typical industry standards, require that all parts of the FBC interconnected system meet both normal (N-0) and single contingency (N-1) transmission planning criteria. To satisfy the single contingency (N-1) planning criterion, an outage of a single element of the power system must not result in load loss. Satisfying this planning criterion allows FBC to reliably maintain service.[24]

27. 11E Line supply (i.e. the ASM Terminal Station) is part of the interconnected system, and is required to meet both normal operation (N-0) and single contingency (N-1) transmission planning criteria.[25] Currently, all other parts of the FBC interconnected system achieve this N-1 planning criteria, with the exception of the ASM Terminal Station.[26]

28. Any time when load might exceed the capabilities of one of the ASM Transformers, the N-1 Transmission System Planning Criteria for 11E Line supply is not being met.[27] With the current capacity of the ASM transformers and current load, FBC's electricity demand in the Boundary and Similkameen areas has exceeded the N-1 Transmission Planning Criteria.[28]

29. In the event of an outage or failure of one of the ASM Transformers (an N-1 event) in current peak demand conditions, the remaining ASM transformer would be overloaded (i.e. it would exceed the transformers' 80 MVA nameplate (normal) rating) and be unable to meet customer loads.[29] As a result, FBC will not be able to reliably maintain service during peak periods.[30] Based on actual 2022 data, if one of the ASM Transformers had failed and been non-operational through 2022, the remaining transformer would have been overloaded for approximately 23 percent of the year.[31]

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24 Ex. B-1, Application, pp. 2 and 17.
25 Ex. B-1, Application, p. 2.
26 Ex. B-4, FBC Response to BCUC IR1 2.6 and Ex. B-13, FBC Response to BCOAPO 28.1.
27 Ex. B-7, FBC Response to CEC IR1 5.1.
28 Ex. B-1, Application, p. 10.
29 Ex. B-4, FBC Response to BCUC IR1 2.1 and Ex. B-13, FBC Response to BCOAPO 28.1 and 33.1.
30 Ex. B-1, Application, p. 10.
31 Ex. B-4, FBC Response to BCUC IR1 2.1.

### 2. <u>Historical and Forecast Peak Load for the Boundary and Similkameen Areas</u>

30. In preparing its Application, FBC utilized historical data of actual peak loads, and prepared a 1-in-20 peak load forecast. This type of forecast is undertaken for system planning purposes and accounts for possible weather extremes that directly impact winter and summer peak loads, in order to ensure that sufficient capacity is available under adverse conditions.[32] The details of how the 1-in-20 year peak load forecast was prepared is set out in detail in Exhibit B-4, FBC's Response to BCUC IR1 2.8.

31. FBC's use of a 1-in-20 year peak load forecast is consistent with industry practice. The Company has been using this type of forecast for planning purposes since at least 2011. This forecasting method was examined in FBC's Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, and underpins FBC's capital plans, including the 2014-2019 Performance-Based Rates Application and the capital plan filed in the 2020-2024 Multi-Year Rate Plan Application. A 1-in-20 year peak load forecast was also used in FBC's recent Kelowna Bulk Transformer Addition Project CPCN Application, which was approved by the BCUC in Order C-4-20.[33]

32. The historical summer and winter peak loads (2017 through 2022) and the summer and winter peak load forecast (2023 through 2027) for the Boundary and Similkameen Areas are summarized in Tables 3-2 and 3-3 of the Application, as follows:[34]

**Table 3-2: Boundary and Similkameen Areas' Historical Actual Peak Loads, 2017-2022**

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| Summer (MW) | 122 | 121 | 133 | 135 | 148 | 173 |
| Winter (MW)[10] | 128 | 131 | 142 | 145 | 163 | 187 |

**Table 3-3: Boundary and Similkameen Areas' Peak Load Forecast, 2023-2027**

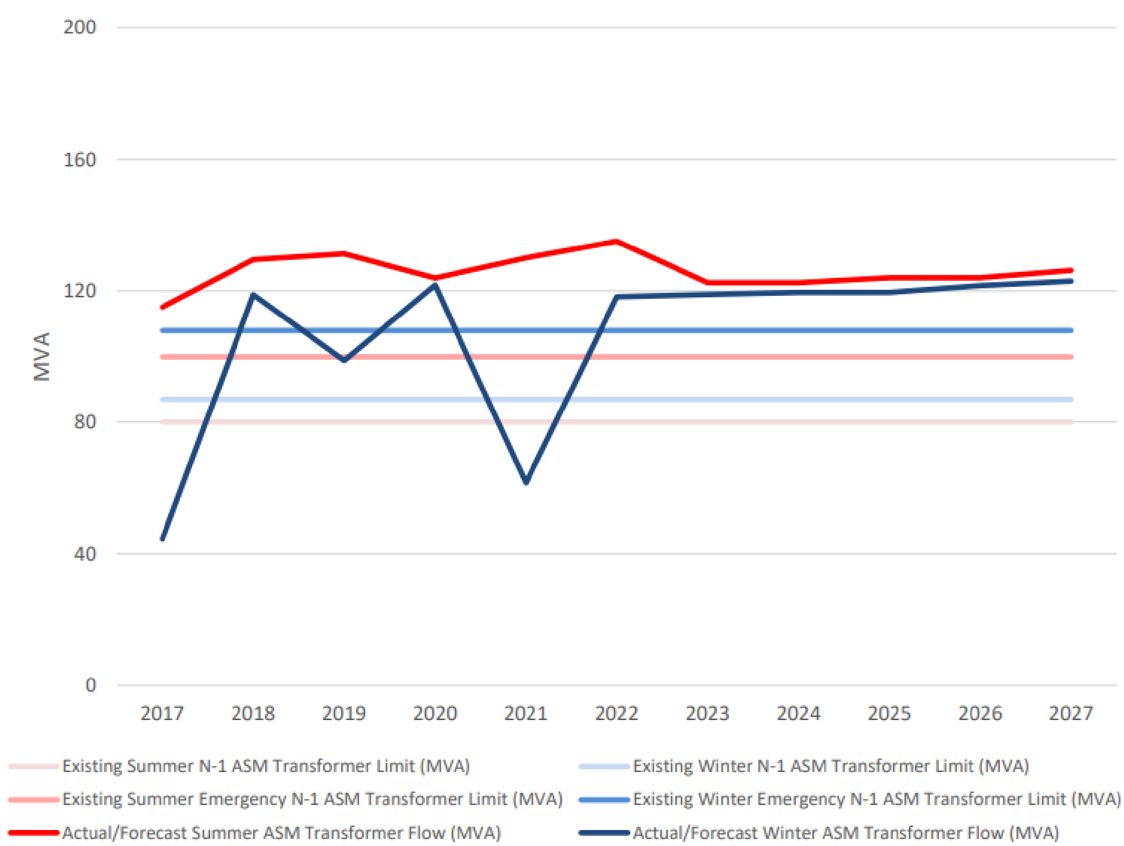
| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Summer (MW) | 163 | 163 | 165 | 165 | 168 |
| Winter (MW)[12] | 177 | 178 | 178 | 181 | 183 |

32 Ex. B-1, Application, p. 17.
33 Ex. B-1, Application, pp. 17-18; Ex. B-7, FBC Response to CEC IR1 6.2.
34 Ex. B-1, Application, p. 18. See also Ex. B-4, FBC Response to BCUC IR1 2.13, for peak load forecasting through 2040.

33. This forecast includes forecast load growth related to electric vehicles (**EVs**) and from one known large capacity customer; however, greater EV adoption and new government policy favouring electrification have the potential to result in increases beyond what is forecast.[35]

34. Figure 3-7 of the Application, included below, depicts the historical and forecast peak load flow through the ASM Transformers specifically (for the period of 2017 through 2027). The load flow through the ASM Transformers is determined by three main factors: (1) the Boundary and Similkameen load (i.e. customer demand), (2) generation dispatch (with generation from the Waneta hydroelectricity facility (**WAN**), which is owned by BC Hydro, having the greatest impact), and (3) system configuration.[36] Figure 3-7 compares the historical and peak load flow to the normal and emergency ratings of a single ASM Transformer (i.e. what would be operating following an N-1 contingency event, which caused an outage or failure of the other ASM Transformer):[37]

**Figure 3-7: ASM Terminal Station's Contribution to the Boundary and Similkameen Areas' Total Load Compared to the N-1 Transformer Limits[13]**




35 Ex. B-1, Application, p. 18.
36 Ex. B-4, FBC Response to BCUC IR1 2.11; Ex. B-12, FBC Response to CEC IR2 38.1.
37 Ex. B-1, Application, p. 19.

35. In an N-1 contingency event, the summer peak load flowing through the ASM Terminal Station has exceeded both the normal and emergency ratings of a single ASM transformer. While winter peak load has historically been more variable (mainly due to fluctuations in generation dispatch from WAN), in recent years FBC has also exceeded N-1 system planning. Peak load is forecast to continue to exceed the normal and emergency ratings of a single ASM Transformer in both the winter and summer going forward.

36. The transformer load at the ASM Terminal Station has been exceeding the existing summer normal and emergency limits in an N-1 situation, since at least 2014.[38] Through an assessment performed in 2019, FBC identified that the potential to exceed the N-1 transformer emergency limits had increased in both frequency and size, due to customer load growth. Further, when this load growth is coupled with the other contributors to the load flow through the ASM Transformers (i.e. generation dispatch and system configuration), the risk of a contingency event has also increased on account of there being more potential for overlap of these contributors on the system. The frequency where these high load situations will occur will only become greater in the future, as customer load continues to grow.[39]

### 3. FBC has Managed Operationally, but this is not a Sustainable Solution

37. To date, FBC has been able to manage customer load through the ASM Transformers operationally. The two most effective options for dealing with potential overloading have been identified as operating the 11 Line path radially or, as a last resort, shedding load.[40]

38. However, these operational changes are not sustainable.[41] They are in violation of FBC's Transmission Planning Criteria, which requires that after the loss of a single, non-radial element, the system shall remain within the emergency ratings and limits, without any loss of load.[42]

39. To the extent the operational procedures require the action of BC Hydro (adjusting generation dispatch from WAN), the procedures are not reliable as BC Hydro is not always in a position to provide such actions. Further, as load continues to increase, even where BC

[38] Ex. B-10, FBC Response to BCUC IR2 28.1.
[39] Ex. B-10, FBC Response to BCUC IR2 28.1.
[40] Ex. B-4, FBC Response to BCUC IR1 2.1; Ex. B-10, FBC Response to BCUC IR2 28.2.
[41] Ex. B-1, Application, p. 19.
[42] Ex. B-4, FBC Response to BCUC IR1 2.21.

Hydro is in a position to provide operational procedures, they may not be sufficient to avoid overloading.[43]

40. Further, to the extent that 11E Line is opened, this causes the Boundary area to be fed radially (i.e. from only one source, the Kootenays). There is no redundancy and this operational change reduces the reliability of supply, as any further contingency would cause a blackout to the entire Boundary area (leaving approximately 4,900 customers without power). Opening 11E Line is not a long-term solution.[44]

41. Finally, with respect to shedding load, this is always used as a last resort, for a safety or extreme emergency situation, when no other option is available. It would not be used under any planned operating conditions.[45]

42. Continuing to use operational changes are not a sustainable or reliable long-term solution.

### 4. Impact of Overloading on Transformer Life

43. Further, overloading one of the existing ASM Transformers is detrimental to the lifespan of the transformer. The normal limits of each of the ASM Transformers is 80 MVA (summer) and 88 MVA (winter), while the emergency limits are 100 MVA (summer) and 108 MVA (winter). FBC's Operating Procedures allow for an ASM Transformer to be operated above the normal limit (but below the emergency limit) for a maximum of six hours. The Operating Procedures allow for no operation over the emergency limit.[46]

44. These limits exist, in part, in order to not significantly reduce the expected remaining lifespan of the transformer.[47] Prolonged loading of a transformer in the emergency range increases the winding hot spot temperature (the temperature in the hottest area in the transformer). As the relationship between temperature and lifespan is exponential, consistent overloading could reduce the average 40-year lifespan of a transformer to less than a year (while lightly loading a transformer can have the opposite impact, of increasing life expectancy).[48]

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43 Ex. B-10, FBC Response to BCUC IR2 28.2.
44 Ex. B-4, FBC Response to BCUC IR1 2.1 and 2.21; Ex. B-13, FBC Response to BCOAPO IR2 23.2.1, 23.3 and 23.5.
45 Ex. B-10, FBC Response to BCUC IR2 28.2; Ex.B-13, FBC Response to BCOAPO IR2 24.2.
46 Ex. B-4, FBC Response to BCUC IR1 2.17.
47 Ex. B-4, FBC Response to BCUC IR1 3.1.
48 Ex. B-1, Application, p. 20.

45. The existing ASM Transformers are extremely important system assets, with replacement lead times in excess of a year. Planned overloading above their nameplate (normal) rating is not an acceptable practice, particularly when coupled with their current condition, discussed next.[49]

## C. THE CONDITION OF THE ASM TRANSFORMERS

46. The deteriorating condition of the ASM Transformers is another factor driving need for the ASM Project. As previously noted, ASM T1 and ASM T2 are 57 and 51 years old, respectively.[50]

47. FBC commissioned Hitachi Energy, a third-party consultant and global leader in power transformers, to perform a comprehensive condition assessment for the ASM Transformers. A copy of Hitachi's complete report (the **Hitachi Report**) is at Appendix B of FBC's Application.

48. The Hitachi Report calculated the probability of failure in any given year of ASM T1 (2.41 percent) and ASM T2 (2.35 percent).[51] The probabilities of failure for each of the ASM Transformers (as assessed by Hitachi) is higher than FBC's accepted failure tolerance of two percent. This tolerance was adopted by FBC, based on CEATI industry findings, for transformers like the ASM Transformers.[52] FBC assesses this risk level as being both "high" (as the probability of failure in any given year is over 2 percent), as well as "unacceptable" (due to the criticality of the ASM Transformers to FBC's system, the lengthy response time caused by the long-lead times for replacement transformers, and the current condition of the ASM Transformers).[53]

49. The Hitachi Report identified the greatest contributor to the risk of failure of the ASM Transformers as the risk of accessory failure. The operation count for the load tap changer (**LTC**) contacts on the ASM Transformers (being the second most failed component for this type of transformer) had exceeded the maximum recommended by the manufacturer for each of the ASM Transformers. While the manufacturer recommends replacement of the

49 Ex. B-1, Application, p. 21.
50 For comparison, according to FBC's available records, the average service life of FBC's other CGE transformers that have operated at the transmission level (like the ASM Transformers) and were retired is 53 years (Ex. B-7, FBC Response to CEC IR1 10.1).
51 Ex. B-1, Application, Appendix B, Hitachi Report, p. 12, Table 2.
52 Ex. B-1, Application, p. 21 and Ex. B-4, FBC Response to BCUC IR1 3.5.
53 Ex. B-13, FBC Response to BCOAPO IR2 39.1.1.

LTC contacts every 80,000 operations, the ASM T1 LTC has undergone approximately 398,183 operations and the ASM T2 LTC has undergone approximately 394,575 operations.[54]

50. The original manufacturer of the LTC equipment used by the ASM Transformers has not been in business since 2004. As a result, while FBC has been able to continue to operate the ASM Transformers because of regular maintenance, in-time oil processing, oil replacement and the use of spare parts procured before the original manufacturer went out of business, it is not able to now refurbish the LTCs, as the necessary equipment cannot be obtained.[55]

51. The risk of failure of one of the ASM Transformers is already above FBC's failure tolerance of 2 percent, and their condition continues to deteriorate with age, with their risk of failure increasing with each year.[56]

## PART 4 - ALTERNATIVE 5 IS THE PREFERRED ALTERNATIVE

### A. THE ALTERNATIVES CONSIDERED

52. The objectives of the ASM Project are: (1) increasing the 161 kV capacity to the Boundary and Similkameen areas (in order to maintain safe and reliable service to customers in these areas), and (2) addressing the aging ASM transformers.

53. FBC identified a variety of alternatives for the ASM Project. A number of the alternatives identified were considered and rejected at a preliminary stage, as they failed to meet the Project's objectives, or were otherwise clearly inferior to other alternatives.[57]

54. Two of the identified alternatives were determined to meet the Project's objectives and to warrant a detailed analysis, specifically:

[54] Ex. B-1, Application, p. 22. See also Ex. B-4, FBC Response to BCUC IR1 3.9 which corrected the error in the number of operations for ASM T1 LTC.

[55] Ex. B-4, FBC Response to BCUC IR1 3.8.1 and 3.8.1.1; Ex. B-6, FBC Response to BCOAPO IR1 17.1.

[56] Ex. B-1, Application, p. 22; Ex. B-4, FBC Response to BCUC IR1 3.6.1; Ex. B-7, FBC Response to CEC IR1 10.5.

[57] See section 4.2 of Ex. B-1, Application for a description of alternatives that were considered and rejected at a preliminary screening stage. These alternatives included Alternative 1 (status quo), Alternative 2 (like-for-like replacement of the ASM transformers), Alternative 4 (building a new terminal station at a greenfield location and demolishing the ASM Terminal Station) and Alternative 6 (retaining the existing ASM Terminal Station and adding a new transformer at WTS). See Ex. B-8, FBC Response to ICG IR1 5.3, for an additional detailed description of why Alternative 6 was eliminated during the pre-screening phase.

a. **Alternative 3 (Rebuild ASM):** Undertake a full rebuild of the existing ASM Terminal Station, in order to replace the existing two ASM Transformers with two new 63/161 kV transformers (each with a rating of 90/120/150 MVA) and upgrade both the 63 kV bus and 161 kV bus; and

b. **Alternative 5 (Expand WTS):** Expand the existing WTS site to add two new 63/161 kV transformers (each with a rating of 90/120/150 MVA), reconfigure the 63 kV ring bus, and install a 161 kV two breaker bus, and then demolish the existing ASM Terminal Station.

55. For each of Alternative 3 and Alternative 5, the transformers to be installed are 63/161 kV transformers, with a rating of 90/120/150 MVA, which is the current industry standard size for transformers in applications of this type.[58] FBC considered four different sizes of transformers (80 MVA, 120 MVA, 150 MVA and 200 MVA). It was determined that the 150 MVA size provided sufficient room for growth, without being too large (the 80 MVA and 120 MVA transformers were not large enough, whilst the 150 MVA transformers had a very similar summer emergency rating as 11E Line, and transformers over 150 MVA were too large, as 11E Line became the limiting factor).[59] FBC anticipates that, under the current forecast, the 150 MVA transformers will be sufficient until 2051 (around the same time as the capacity of 11E Line is expected to be reached).[60]

56. Alternative 3 and 5 are described in detail in sections 4.2.3 and 4.2.5 of the Application, respectively.

## B. EVALUATION CRITERIA

57. FBC completed an in-depth evaluation of Alternative 3 and Alternative 5. In doing so, the following evaluation criteria were considered by FBC:

1) **Infrastructure**: (1.1) system reliability, and (1.2) potential for future expansion;

2) **Safety**: (2.1) personnel safety, (2.2) construction safety, and (2.3) ground grid integrity;

58 Ex. B-1, Application, p. 30.
59 Ex. B-4, FBC Response to BCUC IR1 5.5.
60 Ex. B-10, FBC Response to BCUC IR2 29.1.2.

3) **Environmental**: (3.1) ecological, (3.2) air-quality and GHG reductions, and (3.3) archaeology;

4) **Community and Stakeholder Relations**: (4.1) land use and adjacent infrastructure, (4.2) community impact, and (4.3) economic growth;

5) **Indigenous impact**: (5.1) Indigenous relations;

6) **Technical**: (6.1) land availability, (6.2) constructability and operations accessibility, and (6.3) operability; and

7) **Financial**: (7.1) rate impact.

58. For each non-financial criterion (one through six above), FBC scored each of the Alternatives with a 0 (poor choice), 1 (acceptable choice), 2 (good choice) or 3 (best choice). Each non-financial criterion was also assigned an individual weight, as set out in Table 4-1 of the Application, ranging from 4.0 percent to 8.1 percent.

59. FBC's scoring approach, evaluation criteria and weighting was established through engagement and collaboration of FBC's internal stakeholders, taking into account existing and emerging issues and risks, previous experience from similar projects, specific attributes of the current project, and feedback provided by Indigenous communities, public stakeholders and customers.[61]

60. The results of FBC's evaluation of non-financial criteria for Alternative 3 and Alternative 5 are set out in detail in Table 4-3 of the Application. In summary, the weighted totals for Alternative 3 and Alternative 5 were as follows: [62]

| | **Alternative 3** | **Alternative 5** |
|---|---|---|
| Weighted Total | 1.43 | 2.39 |

61. Based on the non-financial criteria, Alternative 5 is superior to Alternative 3. While FBC relies on the full non-financial evaluation (summarized in section 4.3.3.2 of the Application), it highlights a few points below, based on the questions raised in IRs:

a. For each of the non-financial criteria, Alternative 5 scored the same or better than Alternative 3, with the exception of land availability (criterion 6.1).

[61] Ex. B-4, FBC Response to BCUC IR1 7.1; Ex. B-7, FBC Response to CEC IR1 19.0.
[62] Ex. B-1, Application, p. 39.

b. With respect to land availability, Alternative 3 received a score of 2.5 while Alternative 5 received a score of 2.0. This evaluation included the fact that FBC already owns the ASM Terminal Station land, while the WTS land is owned by Teck Metals Ltd. (with FBC having existing statutory rights-of-way (**SRWs**) at WTS).[63]

c. With respect to the potential for future expansion (criterion 1.2), Alternative 3 received a score of 0 (as the ASM Terminal Station it is unable to accommodate a third 63/161 kV transformer or additional transmission lines at the 63 kV or 161 kV level the future), while Alternative 5 received a score of 2 (as the WTS site has potential to accommodate this type of future expansion).[64]

d. Alternative 5 has better constructability (criterion 6.2) than Alternative 3, with less outages being necessary during construction, lower construction risk, simpler staging and less equipment procurement risk.[65] Alternative 3 has higher construction risk, in part, due to it being a brownfield site in close proximity to energized equipment and requiring complex staging and outage planning for the duration of the Project. In contrast, Alternative 5 would be completed on a greenfield construction site, resulting in simpler outage planning and staging.[66]

62. FBC also performed a financial evaluation, which considered the capital costs of each of Alternative 3 and Alternative 5, as well as incremental O&M expense and the levelized rate impact of each of Alternative 3 and Alternative 5, over a 53-year analysis period.[67]

63. A summary of this evaluation is found in Table 4-4 of the Application, as follows:

**Table 4-4: Financial Evaluation Summary of Alternatives 3 and 5**

| | Alternative 3: Rebuild ASM | Alternative 5: Expand WTS |
|---|---|---|
| Capital Costs, including AFUDC[29], AACE Class 4, As-spent ($ millions) | 43.517 | 28.378 |
| Incremental O&M Expense in 2027, As-spent ($ millions) | 0.014 | 0.002 |
| Total PV of Incremental Revenue Requirement over 53 Years ($ millions) | 57.736 | 37.372 |
| Levelized Rate Impact over 53 Years (%) | 0.82 | 0.53 |

63 Ex. B-1, Application, p. 38.
64 Ex. B-4, FBC Response to BCUC IR1 8.1.
65 Ex. B-1, Application, pp. 38-39; Ex. B-4, FBC Response to BCUC IR1 8.3.
66 Ex. B-4, FBC Response to BCUC IR1 8.4.
67 Ex. B-1, Application, pp. 39-40. The 53-year analysis period is based on a three year construction period (2024-2026) plus a 50-year post-project period running from when all assets are estimated to enter FBC's rate base, in 2027.

64. Key reasons for why the construction costs of Alternative 3 are higher than Alternative 5 (resulting in higher capital costs), include: (a) Alternative 3 includes eight high voltage breakers with associated equipment, whereas Alternative 5 includes three high voltage breakers and associated equipment, (b) Alternative 3 requires the addition of a new control building at the ASM Terminal Station, whereas Alternative 5 uses space in the existing building at WTS for the expansion, (c) Alternative 3 involves rebuilding the ASM Terminal Station, which is mostly brownfield construction staging, whereas Alternative 5 involves expanding WTS with mostly greenfield practices and little construction staging.[68]

65. Overall, Alternative 5 has lower capital costs than Alternative 3, and a lower present value of incremental revenue requirement and, therefore, a lower impact to customer rates over the 53-year analysis period.[69]

## C. ALTERNATIVE 5 IS THE PREFERRED ALTERNATIVE FOR THE PROJECT

66. While both Alternative 3 and Alternative 5 satisfy the objectives of the ASM Project, the preferred solution is Alternative 5.

67. Alternative 5 meets FBC's Transmission System Planning Criteria, improves system reliability, has the potential for future expansion, and delivers the necessary safety performance. It also carries less risk associated with construction and system operation during construction, and it has less long-term maintenance needs. In addition to being superior in terms of the non-financial criterion, Alternative 5 also has lower capital costs than Alternative 3 and a lower rate impact. [70]

# PART 5 - PROJECT DESCRIPTION

68. Alternative 5, the proposed ASM Project, involves the following key components:

    a. Reconfiguring the 63 kV egress at WTS for 34 Line, 9 Line and 10 Line;

    b. Expanding the WTS footprint;

    c. Installing two additional 63/161 kV transformers, reconfiguring the 63 kV ring bus and adding a 161 kV two breaker bus;

[68] Ex. B-6, FBC Response to BCOAPO IR1 14.1.
[69] Ex. B-1, Application, p. 40.
[70] Ex. B-1, Application, p. 40.

d. Converting 34 Line to 161 kV rating, then connecting 11E Line from the ASM Terminal Station to WTS by repurposing 34 Line as an extension to 11E Line; and

e. Demolishing the ASM Terminal Station, above grade.[71]

69. The details of the proposed ASM Project, including Project engineering and design, Project management and resources, Project access and staging, Project schedule and a risk assessment are set out in Part 5 of the Application. In this Argument, FBC highlights a few points with respect to the Project, based on questions raised in IRs.

70. The ASM Project will require certain land modifications. Briefly, WTS facilities are located within an existing SRW (**SRW1**) and the existing transmission connection (34) Line between WTS and the ASM Terminal Station is within another existing SRW (**SRW2**).[72] FBC has entered into an Agreement to Grant with the landowner of the WTS site, Teck Metals Inc. This Agreement provides for the modification of the legal agreements regarding SRW1, in order to allow for substation works of 63 kV to 230 kV. It also provides for an additional SRW, that is necessary for the transmission work. The Agreement to Grant is subject to customary subject conditions,[73] the timing of which are all within FBC's control, other than obtaining BCUC approval for the Project. FBC expects that the SRWs will be modified/registered within two to three months of FBC satisfying the subject conditions in the Agreement to Grant.[74]

71. The ASM Project will also require approvals/permits from the Minister of Transportation and Infrastructure (**MOTI**) and Canada Pacific Rail (**CPR**). FBC will submit a permit application to MOTI, and will begin discussion with CPR, once it has necessary details from the detailed design phase for the Project. FBC does not anticipate any problems with obtaining the necessary approvals and permits.[75]

72. The station modifications necessary as part of the ASM Project are described in section 5.1.2 of the Application. Once the first of the new WTS transformers (**WTS T3**) is put into service, and 11E Line is interconnected to 34 Line to extend back to WTS, the ASM Terminal Station will enter standby mode. This has the advantage of providing a secondary station to

71 Ex. B-1, Application, p. 40.
72 Ex. B-1, Application, pp. 42-43.
73 See Ex. B-10, FBC Response to BCUC IR2 31.2. for these conditions.
74 Ex. B-4, FBC Response to BCUC IR1 11.0; Ex. B-10, FBC Response to BCUC IR2 31.1.
75 Ex. B-4, FBC Response to BCUC IR1 11.0; Ex. B-6, FBC Response to BCOAPO IR1 16.1 and 16.2.

supply 11E Line, in the event that WTS T3 were to experience an early-life failure (within the first three months of operation) before the second new transformer (**WTS T4**) is available. FBC is of the view that the advantages from maintaining this reliability outweighs the O&M expenses that FBC will continue to incur for the ASM Terminal Station while it is in standby, and the increased Project costs to restore the ASM Terminal Station.[76] The existing ASM Terminal Station will be demolished at the end of the Project, following completion of the work at WTS.[77]

## PART 6 - PROJECT COST

73. With respect to Project costs, the total capital cost of the ASM Project is forecast to be \$35.179 million in as-spent dollars. FBC developed this cost estimate to a Class 3 level of definition, as defined by the Association of Advancement of Cost Engineering (**AACE**) recommended practice, and in accordance with the BCUC's CPCN Guidelines.[78]

74. Details of the Project cost estimate is set out in Part 6 of the Application.

75. The Project cost estimate includes a contingency estimate of \$3.318 million in 2022 dollars (or approximately 13.1 percent of the total base capital cost estimate). This contingency amount was determined by applying a contingency of 15 percent to the station construction and removal costs (before materials handling and provincial sales tax), and a contingency of 10 percent for the transmission, distribution and fibre modifications components.[79] The lower contingency for the transmission, distribution and fibre modifications reflects a lower assessed risk and lower potential for specific scope escalation due to better-defined scope; whereas the higher contingency for station construction and removal costs reflects the higher assessed risk and potential for scope escalation.[80]

76. The contingencies used are within the range of contingencies for an AACE Class 3 estimate that are typically applied to FBC's projects, and is consistent with the level or risk and uncertainty associated with the Project.[81]

[76] Ex. B-4, FBC Response to BCUC IR1 10.5.
[77] Ex. B-1, Application, p. 44.
[78] Ex. B-1, Application, p. 55; Order G-20-15, 2015 Certificate of Public Convenience and Necessity Application Guidelines, s. 5(iii).
[79] Ex. B-1, Application, p. 56.
[80] Ex. B-4, FBC Response to BCUC IR1 15.1.
[81] Ex. B-12, FBC Response to CEC IR2 45.1 and 45.2.

77. All new assets related to the Project are expected to be in-service in 2025 and will be transferred to rate base on January 1, 2027, resulting in an incremental rate impact of approximately 0.58 percent in 2027, when compared to the approved 2023 rates. This rate impact is equivalent to approximately $0.707 per MWh when compared to FBC's 2023 approved rates. For an FBC residential customer consuming 11,000 kWh per year, this could equate to a total bill impact of approximately $7.80 in 2027.[82]

## PART 7 – ENVIRONMENTAL & ARCHAEOLOGY

78. With respect to environmental considerations, WTS is an active FBC substation, located within an SRW on a larger parcel owned by Teck Metals Ltd. The WTS is a Contaminated Sites Regulation (**CSR**) Schedule 2 activity.[83]

79. A Stage 1 Preliminary Site Investigation was completed by Bear Environmental Limited for the WTS site in November 2022, which identified three Areas of Potential Environmental Concerns (APECs) with Contaminants of Potential Concern (COPC), including the current substation, fertilizer truck staging area and Teck Wide Area surface soil impacts. The Stage 1 Investigation confirmed that there is no record of substation incidents potentially resulting in a release of contaminants to the environment over and above typical operations, and that further investigation within the substation is not recommended at this time.[84]

80. As there is a likelihood of impacted surface soils within the footprint of the proposed expansion, Teck Metals Ltd. has indicated that their licensed Teck Trail Operations Landfill can be used for soil disposal. This location is proximate to the Project site, and the soil to be excavated during the Project is expected to meet Teck's waste soil requirements. However, if it does not, FBC has identified a facility in Swan Hills, Alberta as the preferred backup location, as it is the closest authorized treatment and disposal facility for hazardous materials contamination in soil. No additional permits or approvals are required for disposing of contaminated soil at the Swan Hills facility.[85]

81. With respect to archaeology considerations, FBC engaged Nupqu Limited Partnership (**Nupqu**) as an archaeological consultant for the Project. Nupqu has obtained the *Heritage Conservation Act* Section 12.2 Multi-assessment Permit 2022-0110, which is applicable to

[82] Ex. B-1, Application, p. 60.
[83] Ex. B-1, Application, p. 61.
[84] Ex. B-1, Application, p. 61.
[85] Ex. B-1, Application, p. 61; Ex. B-10, FBC Response to BCUC IR2 34.3.

undertaking an Archeological Impact Assessment (**AIA**).[86] Nupqu, on behalf of FBC, provided notification and the opportunity to participate in the AIA to 11 different Indigenous communities, and 3 participated in the AIA.[87]

82. Nupqu completed an AIA under this permit in April 2023. No archaeological materials or sites were observed, recorded or otherwise suspected within the location of the Project footprint. Nupqu prepared a Letter of Notice, which recommends that no further archaeological work is required for the Project footprint, but that a chance find / stop work be developed and provided to construction crew members.[88] FBC has a corporate Heritage Resource Management (Chance Finds) procedure, which is applicable to all projects the Company undertakes.[89] An initial draft of Nupqu's AIA results and recommendation report is expected in Q4 2023, and will be sent to impacted Indigenous communities for their review.[90]

## PART 8– CONSULTATION AND ENGAGEMENT

83. Public consultation and communication are integral components of FBC's project development process. Indigenous communities and stakeholders, including local governments, municipalities, local residents and Teck Metals Ltd., have been notified of the proposed Project in order to provide the opportunity to engage on the Project.[91] As is described in more detail in this section, the consultation undertaken by FBC to date with Indigenous communities and stakeholders has been sufficient, and will continue moving forward.

84. Overall, the ASM Project is expected to have minimal impacts on the community: it involves only modest excavation, which will be conducted primarily within existing SRWs and within FBC facilities. As a result, FBC's consultation and engagement activities have been largely targeted towards the Indigenous communities that have been identified as having asserted interests in the territory, as well as local governments and other stakeholders who live or work near the location of the Project.[92] FBC's consultation activities with these groups are described in detail in Part 8 of the Application.

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[86] Ex. B-1, Application, p. 62; Ex. B-4, FBC Response to BCUC IR1 21.1.
[87] Ex. B-4, FBC Response to BCUC IR1 26.1.
[88] Ex. B-4, FBC Response to BCUC IR1 21.3.
[89] Ex. B-10, FBC Response to BCUC IR2 35.3.
[90] Ex. B-10, FBC Response to BCUC IR2 35.2.
[91] Ex. B-1, Application, p. 65.
[92] Ex. B-1, Application, p. 65.

85. With respect to the Local Community, FBC identified the stakeholders potentially affected by the Project (see section 8.2.1 of the Application) and notified them of the Project.[93] FBC received only a small number of inquiries and responses, which are tracked in its Stakeholder Consultation Log (Appendix I-1 of the Application) and summarized in the Application.[94]

86. FBC continues to monitor for feedback from local government and stakeholders, and remains committed to timely, meaningful engagement, should any Project feedback or concerns from local government or stakeholders be received. No issues or concerns have been raised by local government or stakeholders since the filing of the application.[95]

87. Likewise, with respect to Indigenous Communities, FBC identified Indigenous groups potentially affected by the Project (see Table 8-1 of the Application) and sent notification packages.[96] FBC received replies from five Indigenous communities, which are tracked in its Indigenous Engagement Log (Appendix I-1 of the Application) and summarized in section 8.3.3 of the Application. The Penticton Indian Band and Okanagan Indian Band each requested that further engagement be deferred to the Osoyoos Indian Band, which requested an extension of time to consider FBC's notification letter before they responded. This request was granted, and the review period passed without comment. FBC also provided information requested by both the Ktunaxa Nation Council and the Splats'in.[97]

88. FBC maintains consistent working relationships with Indigenous communities in its service area, and will identify potential opportunities for procurement with the Project.[98] Since filing the Application, FBC has engaged with Kakin Resource Corporation, which is fully owned by the Tobacco Plains Indian Band, and discussed an overview of the Project and timelines to identify potential procurement opportunities.[99] FBC continues to monitor for feedback from Indigenous communities, and remains committed to timely, meaningful engagement, should any Project feedback or concerns from Indigenous communities be received. No issues or concerns have been raised by Indigenous communities since the filing of the application.[100]

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93 See Ex. B-1, Application, pp. 65-66.
94 Ex. B-1, Application, p. 66.
95 Ex. B-4, FBC Response to IR1 22.1 and 24.1; Ex. B-10, FBC Response to BCUC IR2 36.4.
96 See Ex. B-1, Application, s. 8.3.1 on pp. 67-68.
97 Ex. B-1, Application, pp. 68-59.
98 Ex. B-4, FBC Response to IR1 27.1.
99 Ex. B-10, FBC Response to BCUC IR2 36.1.
100 Ex. B-6, FBC Response to BCOAPO IR1, 22.1 and Ex. B-10, FBC Response to BCUC IR2 36.2.

## PART 9 - CONCLUSION

89. The need for the ASM Project is driven by load growth in the Boundary and Similkameen areas, which has resulted in the inability for FBC to meet the applicable criteria (N-1, single contingency) in its Transmission System Planning Criteria, triggering potential reliability issues, as well as the deteriorating condition of the ASM Transformers. The ASM Project meets these Project objectives, in a cost effective manner and while minimizing rate impact, and is in the public convenience and necessity.

90. In all the circumstances, FBC requests that the approvals sought in the Application be granted, namely that FBC be granted a CPCN with respect to the ASM Project.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Counsel for FBC:

E Miller

Erica Miller

Dated: September 26, 2023

**BRITISH COLUMBIA UTILITIES COMMISSION**

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

and

FortisBC Inc.'s Application for a Certificate of Public Convenience and Necessity
for the A.S. Mawdsley Terminal Station Project

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# BOOK OF AUTHORITIES OF FORTISBC INC.

**SEPTEMBER 26, 2023**

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**FortisBC Inc.**

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# INDEX

**IN THE MATTER OF**

**BRITISH COLUMBIA TRANSMISSION CORPORATION**

**AN APPLICATION FOR A**
**CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY**
**FOR THE VANCOUVER ISLAND TRANSMISSION**
**REINFORCEMENT PROJECT**

# DECISION

**July 7, 2006**

**Before:**

**Robert H. Hobbs, Chair**
**Nadine F. Nicholls, Commissioner**
**Liisa A. O'Hara, Commissioner**

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## EXECUTIVE SUMMARY

In this Decision the Commission has concluded that VITR is a more cost-effective project to meet the load requirements of Vancouver Island than either VIC or JdF. The appropriate analysis for comparing the costs of the three projects is to compare total direct and indirect costs. For the purposes of comparing the total direct and indirect costs, Sea Breeze and BCTC do not agree on two fundamental aspects of the projects: 1) the system benefits and incremental losses from using HVDC Light® technology to meet the needs of Vancouver Island customers, and 2) how JdF will be used, and therefore the costs of using JdF.

The Commission has concluded that the system benefits of HVDC Light® technology are limited to the reduced need for synchronous condensers on Vancouver Island and VAr compensation on the Lower Mainland and accepts BCTC's calculation of incremental losses. Further, the Commission has concluded that additional firm transmission service must be purchased for the use of JdF in order to meet reliability planning criteria for Vancouver Island. A comparison of the total direct and indirect costs of the three projects turns on these three conclusions. The total direct and indirect costs of VIC and JdF have been found to be approximately $149 million and $126 million, respectively, more than the direct and indirect costs of VITR.

The project alternatives are compared on other project characteristics, including seismic risk, risks of delay, risks of financing, and environmental and health effects. These other project characteristics are not found to be determinative. However, a comparison of the total direct and indirect costs is found to be determinative. Therefore, the Commission has concluded that VITR is a more cost-effective project alternative than either VIC or JdF, and is in the public interest.

In this Decision the Commission has concluded that VITR should be modified, and that Option 1 should replace Option 2 as the route through South Delta. The route options through South Delta and the Gulf Islands are considered and ranked against financial, non-financial and socioeconomic criteria. Although the Commission has approved the least cost route option, the non-financial and socioeconomic criteria are significant considerations relevant to the selection of the preferred route option.

In this Decision non-financial and socioeconomic differences amongst route options are afforded little or no weight where the beneficiaries do not express a preference or the non-financial and socioeconomic differences are in dispute. For example, TRAHVOL does not express a preference for either Option 1 or 2 and views the use restrictions differently than BCTC does. Further, where there are significant financial differences amongst route options and less significant non-financial or socioeconomic differences amongst route options, then the financial differences are afforded considerable weight in this Decision. For example, the aesthetic benefits of undergrounding across the Gulf Islands need to be considered in the context of the significant costs for undergrounding. After considering financial, non-financial and socioeconomic criteria, the Commission has concluded that Option 1 in both South Delta and the Gulf Islands are the preferred route options.

In this Decision a cost control/incentive mechanism is found to be appropriate, in part, because a prudency review and a cost control/incentive mechanism serve different purposes for ratepayers. Further, a cost control/incentive mechanism designed to encourage good management is considered necessary, particularly given the recent management turnover at BCTC.

**Note to Reader:**

All acronyms are defined in the List of Acronyms accompanying the Decision. All dollar values are in nominal dollars, unless otherwise stated. Capital costs that occur over several years are summed in nominal, as spent dollars, unless otherwise stated. The project comparisons in Section 7 of the decision are based on real $2005, unless otherwise stated.

# 1.0 THE CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND THE REGULATORY PROCESS

It has been known for some time that an upgrade to Vancouver Island's electricity supply system is needed. Several solutions to Vancouver Island's supply problem, including both transmission and generation alternatives, have been proposed. This Section sets out some relevant determinations from past Commission decisions and provides a brief description of the solutions now being proposed. This Section closes with a summary of the major steps in the regulatory process that was established to deal with the CPCN applications that were filed with the Commission in this proceeding.

## 1.1 The Need to Reinforce Supply to Vancouver Island

Vancouver Island's electricity needs are currently met by a combination of transmission and on-Island generation. Transmission provides approximately 70 percent of Vancouver Island's peak load, while on-Island generation provides the remaining 30 percent. There are three existing transmission interconnections with the mainland: two 500 kV ac circuits commissioned in 1983 and 1985 between Pender Harbour and Qualicum Bay; two HVDC circuits commissioned in 1969 and 1976 between South Delta and North Cowichan; and two 138 kV ac circuits commissioned in 1956 and 1958, roughly paralleling the HVDC system (Exhibit B1-1, p. 1).

BCTC states that the 500 kV circuits are in excellent condition. However, the ageing HVDC circuits will be de-rated to zero, meaning that they can no longer be relied on to provide dependable capacity for planning purposes, in the fall of 2007. Further, while BCTC considers that the 138 kV cables remain suitable as local supply circuits to serve the southern Gulf Islands, they are no longer used for bulk power transfers to Vancouver Island except during emergencies (Exhibit B1-1, p. 1). These decreases in available transmission capacity mean that Vancouver Island's power supply system will no longer meet applicable reliability criteria after 2007, as described further in Section 4.1.

BCTC based the VITR Application on BC Hydro's October 2004 load forecast (Exhibit B1-1, p. 91), and it used the December 2005 update of that forecast to carry out some EENS studies (e.g., Exhibit B1-47, BCUC 3.186.1, *Expected Energy Not Served (EENS) Study for Vancouver*

*Island Transmission Reinforcement Project—Part I: Reliability Improvements due to VITR*, p. 2). Based on those forecasts, BCTC concludes that there will be a significant shortfall in firm transmission capacity to Vancouver Island beginning when the HVDC system is de-rated, and that the shortfall will grow over time (Exhibit B1-1, pp. 91-93). Participants paid little attention to the load forecast until the Oral Phase of Argument, at which time IRAHVOL brought forward a motion to reopen the record to include the most recent load forecast from BC Hydro's F2007/F2008 Revenue Requirements Application. The motion was denied, in part based on the Commission Panel's finding in Section 2.4 that there is sufficient information on the record regarding the Vancouver Island load forecast. The Commission Panel notes that the most recent load forecast shows a higher Vancouver Island load than was previously indicated.

### 1.2 Previous Commission Decisions

The Commission has addressed the growing supply/demand imbalance and the need for reliable service to Vancouver Island in previous decisions. At page 27 of the VIGP Decision dated September 8, 2003, the Commission accepted that there would be a capacity shortfall on Vancouver Island commencing in the winter of 2007/08. In that Decision, the Commission recognized that a transmission line might become the best reliability option if on-Island generation became prohibitively expensive (p. 57), and it stated that there is a need to move expeditiously to reinforce the electricity supply to Vancouver Island (p. 78). The Commission reiterated its finding that there is a pending capacity shortfall on Vancouver Island at page 3 of the CFT Decision dated March 9, 2005. The Commission Panel notes that the supply contract with the Duke Point Power Plant, which was a subject of the CFT Decision, was subsequently cancelled by BC Hydro.

In August 2005 the Commission Panel encouraged participants to identify, from among the issues that had been considered in previous Commission decisions, any issues that they wanted to have included within the scope of this proceeding (Exhibits A-6 and A-11). BCTC submitted that the following four previously considered issues were relevant to the VITR proceeding (Exhibit B1-16):

1. There is a capacity shortfall on Vancouver Island commencing in the winter of 2007/08 and there is a need to move expeditiously to reinforce electric supply to Vancouver Island (VIGP Decision, p. 78).

2. Implicit in the above finding is that the 2007 zero-rating of the HVDC system for planning purposes is reasonable.

3. BC Hydro's 2004 load forecast accurately predicts what would happen at design day temperature (CFT Decision, p. 21).

4. The Commission does not consider controlled load-shedding an appropriate response to single contingency events in the context of long-term planning for the Vancouver Island transmission system except for radial loads (CFT Decision, p. 81).

The only request to re-open an issue came from TRAHVOL, which requested that the zero rating of the HVDC system for planning purposes be considered (Exhibit C3-12). The Commission Panel denied the TRAHVOL application (Exhibit A-28, p. 2).

## 1.3 Vancouver Island Transmission Reinforcement Project

### 1.3.1 Project Description

By Application dated July 7, 2005, BCTC applied pursuant to Sections 45 and 46 of the *UCA* for a CPCN for VITR to reinforce the transmission system serving Vancouver Island and the southern Gulf Islands. As described in the Application, VITR would consist of replacing one of the existing 138 kV transmission lines between BCTC's ARN Substation in South Delta and BCTC's VIT Substation in North Cowichan with a new 67 km, 230 kV transmission line with a capacity of 600 MW. BCTC proposes building the project entirely within the existing 138 kV ROW. BCTC also proposes to upgrade portions of the other 138 kV line, where prudent, to facilitate the installation of a second 230 kV line in the future (Exhibit B1-1, pp. 2, 3, 28-39).

More specifically, VITR, as proposed by BCTC, would involve the following (Exhibit B1-1, p. 2):

(a) Between ARN Substation in Ladner and Tsawwassen Substation (Segment 1), the two existing 138 kV lines on wooden H-frame structures would be removed and replaced by one new 230 kV double-circuit overhead line on single steel poles.

(b) In Tsawwassen (Segment 2), one of the two existing 138 kV wooden H-frame lines would be removed and replaced by an underground 230 kV line between the Tsawwassen Substation and English Bluff Terminal in the existing ROW. In some areas, a second set of underground conduits would be installed to limit repeated impacts on private property if a second 230 kV circuit is installed in the future. The second 138 kV line would remain in place to continue to serve the southern Gulf Islands.

(c) For the Strait of Georgia and Trincomali Channel submarine crossings (Segments 3 and 5), three of the existing single-phase 138 kV cables would be decommissioned and replaced with three new 230 kV submarine cables. The remaining 138 kV submarine cables (three plus one spare) would continue to supply the southern Gulf Islands through existing substations on Galiano and Salt Spring Islands.

(d) On Galiano and Salt Spring Islands (Segments 4 and 6), the majority of the two existing 138 kV lines on latticed steel structures would be replaced by one new 230 kV double-circuit overhead line on single steel poles. The existing latticed steel structures on the long spans between Galiano and Parker Islands would be modified to carry the new circuits. One of the new circuits will be operated at 138 kV to supply the southern Gulf Islands.

(e) A new 230 kV double-circuit line would replace the existing conductors at approximately the same height across Sansum Narrows between Salt Spring Island and Vancouver Island (Segment 7). New structures would be put in place to accommodate the new conductors.

(f) The two existing 138 kV lines on a combination of wooden H-frames and latticed steel structures between Sansum Narrows and VIT in North Cowichan (Segment 8) would be replaced by one new 230 kV double-circuit overhead line on single steel poles.

The VITR facilities will be owned by BC Hydro and operated and maintained by BCTC. In the Application, BCTC estimates the capital cost of VITR at $245 million and expects that it will be in-service by October 2008 (Exhibit B1-1, p. 3).

Several routing options and project alternatives identified by BCTC and Intervenors were reviewed during the proceeding. The VITR route options focused primarily on alternative routes through South Delta, although there were also several route alternatives considered for the Gulf

Islands. With respect to the South Delta Route Options, the proposal set out in the Application for an underground line on the existing ROW in Tsawwassen is referred to as Option 2. Option 1 refers to a new double-circuit overhead line on the existing ROW in that area, while Option 3 is an underground line in Tsawwassen city streets. Option 4 bypasses Tsawwassen by using the existing Highway 17 corridor. Option 5 bypasses Tsawwassen by paralleling the existing HVDC Pole 2 corridor north of Deltaport Way, while Option 6 bypasses Tsawwassen to the east and south through Boundary Bay using a new ROW through U.S. waters. Option 7 involves accelerating the installation of a second set of 230 kV underground cables using either Option 2 or Option 3, and removing both existing 138 kV overhead lines from Tsawwassen Substation to English Bluff Terminal. Intervenors suggested several modifications to the route options proposed by BCTC, and an option to underground portions of the new 230 kV line on the Gulf Islands was discussed.

### 1.3.2 Applicant

Under the *Transmission Corporation Act* and a number of designated agreements between BCTC and BC Hydro, BCTC is responsible for operating BC Hydro’s transmission system. BCTC is also responsible for planning, constructing and obtaining all regulatory approvals for enhancements, reinforcements, and expansions to that system. This responsibility includes entering into commitments and incurring expenditures for capital investments.

The composition of the VITR Project Team, which was summarized in the Application (Exhibit B1-1, p.20), highlights the continuing affiliation between BCTC and BC Hydro. For further clarification, the organization chart for the Project Team was updated by BCTC during the oral hearing (Exhibit B1-72). BCTC provides the executive oversight and program management using the expertise attained through employee transfers from BC Hydro’s Transmission Line of Business in 2003. BCTC has retained BC Hydro Engineering Services to provide significant engineering support for VITR. For seismic and geotechnical matters, as well as for environmental services, the BC Hydro Engineering Services group has been supplemented with further external expertise. The Project Manager for the engineering and design portion of VITR is also an employee of BC Hydro (T18:3179). Under the Key Agreements between BCTC and

BC Hydro, BC Hydro retains primary responsibility for properties and property rights and for aboriginal relations with respect to transmission system assets, operations, and new capital projects such as VITR (Exhibit B1-1, p.23; Exhibit C6-5, Attachments 5 and 6). All other aspects of VITR are BCTC's responsibility.

### 1.4 Vancouver Island Cable Project

On September 30, 2005, Sea Breeze Pacific Regional Transmission System, Inc. applied pursuant to Sections 45 and 46 of the *UCA* for a CPCN for VIC. By letter dated October 14, 2005 (Exhibit B2-3), the Commission was advised that the project had been assigned to Sea Breeze Victoria Converter Corporation ("Sea Breeze").

VIC would consist of a 540 MW HVDC Light® transmission system between BCTC's Ingledow Substation in Surrey and BCTC's Pike Lake Substation in the Victoria area. The system would consist of HVDC converter stations at the Ingledow and Pike Lake Substations and a combination of underground and submarine cable pairs. The proposed route contains an underground segment from Ingledow to White Rock; a submarine segment across Georgia Strait and south of Saturna, Pender, and Salt Spring Islands to the northern end of the Saanich Peninsula; and an underground segment from there to Pike Lake Substation. In its Application, Sea Breeze estimated that VIC would cost $325 million and that it would be in-service by January, 2008. Once constructed, it would be operated by BCTC (Exhibit B2-1, pp. 3, 45-49, 94, 171, 201).

On March 1, 2006, Sea Breeze withdrew its CPCN application (T25:4783-4784). However, Sea Breeze continues to maintain that an HVDC Light® project constructed by BCTC and owned by BC Hydro is a better long-term solution to Vancouver Island's transmission needs than VITR (Sea Breeze Argument, p. 5). If the Commission grants BCTC a CPCN for such a project, Sea Breeze requests that BCTC be ordered to compensate Sea Breeze for its costs in developing and prosecuting VIC (Sea Breeze Argument, p. 100). The proposed BCTC-built HVDC Light® project became known as the "VIC-like" project during the oral hearing, although unless the context demands otherwise, it will be referred to simply as "VIC" for the remainder of this Decision.

### 1.5 Juan de Fuca ("JdF") Project

In the VIC CPCN Application, Sea Breeze submitted that JdF could also provide a long-term solution to Vancouver Island's transmission needs. JdF has been proposed by Sea Breeze's affiliate, Sea Breeze Pacific Juan de Fuca Cable, L.P. It is an international merchant transmission line consisting of 540 MW HVDC Light® underground and submarine cables from BCTC's Pike Lake Substation to BPA's Port Angeles Substation on the Olympic Peninsula. As an international transmission line, JdF falls under the jurisdiction of the NEB rather than the jurisdiction of the Commission (Exhibit B2-1, pp. 5-6). The Commission Panel has considered JdF as an alternative to VITR or VIC for the purposes of its determinations with respect to BCTC's CPCN Application for VITR.

### 1.6 TRAHVOL Section 25 Complaint

By letter dated November 8, 2005, TRAHVOL complained pursuant to Section 25 of the *UCA* that the continued operation of the existing 138 kV lines through Tsawwassen is unreasonable, unsafe, inadequate or unreasonably discriminatory (Exhibit C3-21). TRAHVOL submits that the Commission should order the removal of the 138 kV lines through Tsawwassen (TRAHVOL Argument, p. 41). The complaint is dealt with in Section 10 of this Decision.

### 1.7 The Regulatory Process

The regulatory process for the review of the VITR Application and the other requests underwent a number of changes and extensions over time, including several to accommodate the filing and withdrawal of the VIC CPCN Application. The more significant procedural milestones are summarized in the following:

- Order No. G-70-05 established a Procedural Conference on August 4, 2005 regarding the regulatory process for the review of the VITR Application (Exhibit A-1).

- Following the August 4, 2005 Procedural Conference, Order No. G-72-05 established a Regulatory Timetable that included a Pre-hearing Conference, Town Hall Meetings, and an Oral Hearing commencing on November 23, 2005. The accompanying letter stated that if Sea Breeze filed a CPCN Application, consolidation of the proceedings to review the BCTC and Sea Breeze CPCN Applications would be considered at the Pre-hearing Conference (Exhibit A-6).

- On September 30, 2005 Sea Breeze Regional Transmission System, Inc. [now Sea Breeze Victoria Converter Corporation ("Sea Breeze")] filed a CPCN application (the "VIC Application") for the Vancouver Island Cable Project (the "VIC") and requested that the Commission confirm the consolidation of the review of its VIC Application with the BCTC VITR proceeding. The Commission issued a separate procedural Order No. G-97-05 to initiate the regulatory review of the Sea Breeze VIC Application.

- Order No. G-96-05 extended the Regulatory Timetable so that the Pre-hearing Conference was scheduled for October 21, 2005 and the Public Hearing was scheduled to start November 28, 2005 (Exhibit A-16).

- Following the October 21, 2005 Pre-hearing Conference, Order No. G-109-05 established a Revised Regulatory Timetable that included a Pre-hearing Conference on November 10, 2005. The Public Hearing was to commence January 23, 2006 (Exhibit A-28).

- At the November 10, 2005 Pre-hearing Conference, the Commission Chair granted the Sea Breeze application for consolidation of the proceedings for review of the VITR and VIC Applications (T3:406).

- Order No. G-141-05 issued a Revised Regulatory Timetable, delaying the start of the Public Hearing to February 6, 2006 (Exhibit A-47).

- Town Hall Meetings were held on Salt Spring Island on January 7, 2006 and in Tsawwassen on January 14, 2006.

- Opening Oral Submissions were heard on January 30, 2006, and the proponent consolidation of the Hearing Issues List was heard on February 1, 2006.

- The Hearing Issues List was issued on February 3, 2006 (Exhibit A-70).

- The Public Hearing commenced on February 6, 2006 in Vancouver.

- Sea Breeze withdrew its VIC CPCN Application on March 1, 2006, and the Commission issued a Revised Hearing Issues List on March 7, 2006 (Exhibit A-71).

- The evidentiary phase of the proceeding closed on March 23, 2006.

- By letter dated March 27, 2006, the Chair approved a request from BCTC to strike evidence from the record due to the withdrawal of Sea Breeze's VIC Application (Exhibit A-72).

- By letter dated April 7, 2006, the Commission amended the Argument and Evidentiary Schedule so that the BCTC report on the cable tenders would be filed by May 4, 2006, and all written submissions in the proceeding would be filed by May 16, 2006 (Exhibit A-76).

- An Oral Phase of Argument was heard on May 30 and 31, 2006.

## 2.0 JURISDICTION AND OTHER LEGAL ISSUES

This Section will consider issues related to the jurisdiction of the Commission pursuant to Sections 45 and 46 of the *UCA* and certain other legal issues raised in Argument, Reply, or in motions brought prior to, and during, the Oral Phase of Argument to draw adverse inferences and to expand the record. Specifically, TRAVHOL raises issues of abuse of the Commission's process, bad faith, and breach of the doctrine of legitimate expectations (TRAVHOL Argument, para. 4, 8-22 and 27-34). BC Hydro argues that the Commission should draw an adverse inference against Sea Breeze for the failure of Sea Breeze to call any direct evidence from BPA or Powerex (BC Hydro Reply, para. 8). Sea Breeze submits that the Commission should draw an adverse inference against BCTC for BCTC's failure to fully respond to its letter to BCTC dated May 1, 2006 (Sea Breeze Cable Tender Submission, May 11, 2006). Delta argues that the Commission should draw an adverse inference against BCTC for not producing the ROW agreement through TFN lands (Delta Argument, para. 198-199). Sea Breeze submits that the Commission should draw an adverse inference against BC Hydro for not calling evidence from Powerex (T42:7863-7865). Finally, in letters dated May 29, 2006 several parties bring motions to re-open the record.

### 2.1 Public Convenience and Necessity and the Public Interest

Sections 45 and 46 of the *UCA* authorize the Commission to issue, refuse to issue, or issue with conditions a CPCN for a project such as VITR.

BCTC submits that "…the public interest to be taken into account in determining whether an applied-for project is in the public convenience and necessity can accommodate a broad range of interests and, in BCTC's opinion, certainly the vast majority, if not all the interests that have been expressed in this proceeding" (BCTC Argument, para. 98-100). In support of this proposition, BCTC refers the Commission Panel to two cases: *Memorial Gardens Assn.(Can.)Ltd. v. Colwood Cemetery Co.* [1958] S.C.R. 353 (WeC)[*Memorial Gardens*] and *Sumas Energy 2 Inc. v. Canada* (National Energy Board ) 2005 FCA 377, 343 N.R. 345 (QL) [*Sumas 2*].

In *Memorial Gardens*, the Supreme Court of Canada stated that it would "…be both impractical and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity…the meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found" (para. 8). The Court continued as follows:

> "As this Court held in the Union Gas case, supra, the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission" (para. 9).

In the VIGP Decision the Commission concluded that "…the test of what constitutes public convenience and necessity is a flexible test" (p. 76).

*Nakina (Township) v. Canadian National Railway Co*., (1986), 69 N.R. 124 (F.C.A.) (WeC) [*Nakina*] was cited with approval by the Federal Court of Appeal in *Sumas 2* (Sea Breeze Argument, para. 395). In *Nakina*, the Court found the Railway Transport Committee erred in its failure to consider certain evidence, which the Court considered formed part of the general totality of the general public interest. The Commission Panel notes that the Court went on to state:

> "For clarity, however, I would emphasise that the error lies simply in the failure to consider. Clearly the weight to be given to such consideration is a matter for the discretion of the Commission, which may, in the exercise of that discretion, quite properly decide that other considerations are of greater importance. What it could not do was preclude any examination of the evidence and submissions as to the adverse economic impact of the proposed changes on the affected community" (para. 10).

BC Hydro accepts the Commission's determination at pages 74-77 of the VIGP Decision (BC Hydro Argument, para. 3). The Commission concluded that, for the purposes of Sections 45 and 46 of the *UCA*, the Applicant had to establish that its project was "...the most cost-effective means to reliably meet Vancouver Island power needs." In that decision, the Commission defined "cost-effective" to include "…considerations of project characteristics such as reliability, dispatchability, timing, and location as well as cost or price, in the case of an EPA" (p. 77).

BC Hydro further submits that:

> "The considerations specifically itemized in the VIGP Decision can be adjusted to the specific context of this case by consideration of the rate impact of competing proposals, capacity (both firm and non-firm), reliability (including physical, financial, performance standards and institutional framework), schedule and timing (including consideration of timing of regulatory approvals, financing arrangements, construction period and commissioning), and, finally, consideration of the key risks associated with project completion (including First Nations, non-BCUC approvals, the need for transmission by others, and the scope of public opposition)" (BC Hydro Argument, para. 3).

Several Intervenors submit that the Commission should be concerned with achieving equity among private interests (Sea Breeze Argument, para. 391-402; IRAHVOL Argument, pp. 79-80; Delta Argument, para. 47; Campbell Argument, para. 6; SDSS PAC Argument, para. 12). BCTC submits that the Commission should be concerned about questions of equity in considering the issue of public convenience and necessity. However, it qualifies its response with the comment that "…concerns about questions of equity should always be tempered by the realization that equity can never be fully achieved and that this is never more true than when the Commission is addressing private interests" (BCTC Argument, para. 101). The CEC argues that the Commission has the discretion to determine whether private interests should be included in the consideration of public convenience and necessity and if it does include them, then it "…should consider questions of equity among private interests" (CEC Argument, para. 35).

BC Hydro, on the other hand, submits that the Commission correctly determined in the VIGP Decision that its focus should be on the public interest, as opposed to achieving equity amongst competing private interests was correct. To support its argument, BC Hydro relies on two cases and quotes from the case of *Re Hamilton*, [1937] 1 DLR 807 (N.S.S.C., en banc) to the effect that it is the public convenience and necessity which is to be considered and not that of private individuals. BC Hydro does acknowledge that other matters may be relevant where two proposals are equally cost-effective, but argues that before considering secondary factors, "…the Commission should first determine whether it has a cost-effective proposal before it at all" (BC Hydro Argument, para. 4 and 5).

In response to an observation from the Chair that the interests defined as public interests in paragraphs 4 and 5 of BC Hydro's Argument are narrower than the definitions suggested by any of the other parties in this proceeding, counsel for BC Hydro comments that he was not certain that such was the case. He also submits that on the issue of jurisdiction simpliciter, he would now use *ATCO Gas & Pipelines Ltd v. Alberta* (Energy & Utilities Board), 2006 SCC 4 [*ATCO*] rather than *Re Hamilton* (T41:7592-7593). On the issue of the analogy between the facts in *Re Hamilton* and those in the Application, he submits that the interest of the hotel owner in that case was analogous with those of the residents of Tsawwassen, namely "…a localized interest, affected not with respect to the ratemaking jurisdiction or any of the general powers that are being exercised, but rather with the specifics of the asset being installed or constructed" (T41:7594).

None of the other parties who commented agree that *Re Hamilton* applied to the facts before the Commission. The principal reason given by the parties on this issue was that more recent case law including *Sumas 2, Nakina* and *Memorial Gardens* all provide for a much broader concept of the public interest (BCTC, T41:7609; TRAHVOL, T41:7615-7616;7618-7619;7621-7622; Sea Breeze, T41:7624-7626; SDSS PAC, T41:7634; Delta, T41:7636). Counsel for IRAHVOL relies on *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission),* [1996] B.C.J. No. 379 (C.A.) in his submission that *Re Hamilton* no longer reflects the law (T41:7626-7627). In that decision, Mr. Justice Goldie stated:

> "It has been evident for some years now that the environmental considerations are important in the formulation of the opinion represented by the phrase 'public convenience and necessity'" (para. 35).

The other parties who commented also sought to distinguish *ATCO* as inapplicable to the facts before the Commission Panel (BCTC, T41:7609-7610; Sea Breeze, T41:7625-7626; IRAHVOL, T41:7628-7629).

Counsel for TRAHVOL submits that based on the case law "…everything has to go into the hopper…" in the Commission's determination of the public interest and necessity, but that the Commission Panel has the discretion to determine the weight to be attached to any one factor. He also emphasizes that his clients were also ratepayers (T41:7618-7622).

Counsel for BC Hydro accepts that "…the public interest is the talisman…" and characterizes the issue as one of the breadth of the public interest (T42:7687). He refers to pages 77 and 78 of the VIGP Decision on the issue of "cost-effective" and includes as a reference the statement at page 77 of that decision:

> "Safety, reliability and other impacts are relevant factors [in the determination of what is the most cost-effective project], along with the cost to ratepayers and the impact on the financial ability of the utility."

He acknowledges that the Commission needs to consider issues of the safety of the transmission lines and EMF. However, he seeks to exclude the issue of property values as a factor falling within the definition of "cost-effective" based apparently on *Re Hamilton, ATCO* and the VIGP Decision at page 78 (T42:7690-7692). The Commission in that decision commented as follows:

> "The Commission Panel agrees with VIEC [Vancouver Island Energy Corporation] that it is not concerned with achieving equity among competing private interests or even among competing utilities in its determination of the Application. In this Decision, the responsibility of the Commission Panel is to consider whether VIGP is the best resource solution for the needs of BC Hydro's customers" (p. 78).

Counsel for BC Hydro acknowledges that the Commission, in determining the public convenience and necessity, can hear evidence on private impacts and pointed out that BC Hydro did not object to the relevance of such evidence during the hearing. He submits that while the Commission could have regard to the existence of private impacts, the focus is on the best resource addition for the needs of BC Hydro's customers (T42:7693-7694).

He agrees with counsel for Sea Breeze that the cases need to be considered in the context of their own statute and facts. He seeks to distinguish *Nakina* on its facts as being a Railway Act case and continues to rely on *ATCO*. He concludes with the submission that the position of BC Hydro "…is on all fours with the Commission's decision in VIGP" (T42:7694-7696).

**Commission Determination**

The Commission Panel accepts the submissions of BCTC that there is a broad range of interests that should be considered in determining whether an applied-for project is in the public convenience and necessity. The Commission Panel concludes, as is stated in *Memorial Gardens,* that it is both impractical and undesirable to attempt a precise definition of general application as to what constitutes public convenience and necessity. As the Commission concluded in the VIGP Decision, the test of what constitutes public convenience and necessity is a flexible test. Because the facilities are high voltage transmission lines and in the backyards of residents, the Commission Panel concludes that private interests should be considered in the circumstances of this Decision, although such interests may not be afforded the same weight as the interests of Vancouver Island customers in receiving adequate and reliable power.

The task before the Commission Panel is to select amongst competing project alternatives, and amongst route options and designs for VITR. As stated in the previous paragraph, private interests are to be considered in this Decision. The description of "cost-effective" as described in the VIGP Decision provides further clarification of the appropriate considerations. . The task is not to select the least cost project, but to select the most cost-effective project. Therefore, as suggested by BC Hydro, reliability, safety, schedule, financing arrangements and other factors itemized in the VIGP Decision and revised by BC Hydro are also relevant to the task before the Commission Panel. In this regard, the Commission Panel accepts BC Hydro's view of the considerations that can be included in the definition of cost-effective.

**Given the need for a project to provide adequate and reliable power to Vancouver Island customers, the Commission Panel concludes that it is in the public interest that the most cost-effective alternative be selected from amongst the competing alternatives. Further delay in finding a solution for Vancouver Island customers is not an option that is in the public interest. Moreover, all the alternative solutions for Vancouver Island customers have adverse impacts. The alternatives, including VITR with its several route options, VIC, and JdF, need to be compared to determine the best, most cost-effective means of supplying power to Vancouver Island. Each alternative has different impacts on interests; some of those interests may be considered public interests and others are private interests. The Commission Panel is of the opinion that both public and private interests should be considered in selecting the project alternative and route option that is in the public interest, although the relative weight placed on the different interests may vary.**

### 2.2 Abuse of Process and Procedural Fairness

In Argument, BCTC proposes that the Commission give it 90 days from the date of the Commission's CPCN Order to negotiate an exchange of rights with a majority of the landowners whose properties would be directly impacted by Option 2 through South Delta, and that in the event BCTC cannot secure an agreement to exchange rights with a majority of landowners in that time, the Commission's order should provide for overhead construction on the existing ROW (the "51 Percent Proposal") (BCTC Argument, para. 3). TRAHVOL raises issues of abuse of process, and procedural fairness and contravention of the doctrine of legitimate expectations in response to the 51 Percent Proposal (TRAHVOL Argument, para. 8-22). It submits that the Commission must reject both Options 1 and 2 and BCTC should be directed to fully indemnify TRAHVOL for all costs incurred in connection with its participation in this proceeding (TRAHVOL Argument, para. 4).

TRAHVOL argues that throughout the oral hearing BCTC maintained that Option 2 was the preferred route through South Delta and points to the evidence of Ms. Peverett, the President and Chief Executive Officer of BCTC (T16:2712-2714). It also notes BCTC's evidence in cross-examination that it would not "renege" on "our promise" not to recommend Option 1 unless it was not prudent or economically or technically feasible to proceed with Option 2 (T18:3198). TRAHVOL emphasizes that:

> "Moreover, BCTC <u>never</u> indicated <u>at any point</u> during the seven week hearing that a certain level of "community support" or "manageable risk" were prerequisites to Option 2 being in the public interest and that Option 1 was the default …" [emphasis in the original] (TRAHVOL Argument, para. 16).

TRAHVOL argues that there is nothing in BCTC's Argument that provides highly persuasive reasons for departing from the "serious commitment" made to MLA Val Roddick, Mayor Jackson and Delta Council and Tsawwassen residents. It submits that a basis for approval of Option 2 that depends on 51 percent of the landowners along the ROW being prepared to negotiate does not amount to a highly persuasive reason to revert to Option 1 if the 51 percent requirement is not met. It further submits that such a proposal serves simply as a "tactic" to allow BCTC to "retreat" to Option 1, since BCTC is well aware of the likely outcome of the negotiations (TRAHVOL Argument, para. 20). Alternatively, TRAHVOL argues that if BCTC is sincere in its submission that Option 2 remains the preferred route through South Delta, then BCTC is seeking to use "its broken promise" to leverage the ROW residents into handing over their underground rights to facilitate Option 2 (TRAHVOL Argument, para. 21).

TRAHVOL submits that further cross-examination of Ms. Peverett is now necessary and appropriate to determine, as an example, the "highly persuasive" reasons justifying BCTC breaking its "serious commitment" and its new preference for Option 1. It argues that Commission approval of Option 1 in the absence of an opportunity for cross-examination would be a significant breach of the rules of natural justice and that the promise or serious commitment made by BCTC created a legitimate expectation on the part of Tsawwassen residents that BCTC would not recommend Option 1, thereby precluding the Commission from considering Option 1 and estopping BCTC from making such a recommendation (TRAHVOL Argument, para. 18).

In support of its position, TRAHVOL relies on two cases: *Apotex Inc. v. Canada(Attorney General*), [2000] 4 F.C. 264 (C.A.) (QL) at paragraphs 21-25, 99-127 [*Apotex*] and *Mount Sinai Hospital Center v. Quebec (Minister of Health and Social Services)*, [2001] 2. S.C.R. 281, 2001 SCC 41 at paragraphs 22-38, 90-95 [*Mount Sinai*]. TRAHVOL considers BCTC's conduct in this respect to be “not only abusive”, but “highly dishonourable” and, having regard to its status as a Crown corporation, “particularly deserving of rebuke” (TRAHVOL Argument, para. 22). TRAHVOL further discusses the issue of bad faith in connection with BCTC and Provincial Government correspondence and associated media coverage (TRAHVOL Argument, para. 27-34). TRAHVOL suggests the correspondence and media coverage would have allowed Tsawwassen residents to reasonably conclude “…that they had achieved a significant victory and that BCTC was in the process of looking at ‘options’ other than putting transmission lines along the ROW, <u>either above or below ground</u>” [emphasis in the original].

Delta also expresses concerns about BCTC’s proposal to use Option 1 as a default route (Delta Argument, para. 18-29). It refers to both BCTC correspondence and the evidence of Ms. Peverett and questions what has changed to justify BCTC’s return to Option 1. It says that neither the evidence nor BCTC’s argument “…reveal persuasive reasons for recommending Option 1” and that “…there is no substantive change in conditions between the time the application was filed, and the date BCTC filed its final argument.” It argues that “…BCTC either knew or should have known that local residents and others believed Option 1 was off the table.” Delta also submits that the 51 Percent Proposal is contrary to the public interest and convenience test, since it is tantamount to saying that Option 2 is not in the public interest and convenience if a property exchange threshold cannot be met. Delta further submits that there are practical issues relating to the negotiation proposal, since it does not require good faith negotiations on the part of BCTC.

SDSS PAC’s submissions on BCTC’s alternative relief request are, in part, based on procedural fairness grounds. SDSS PAC submits that it proceeded throughout the hearing on the basis that BCTC would not recommend Option 1 and that the late change in position allowed for no opportunity to properly cross-examine BCTC on its new position. It urges the Commission to dismiss the 51 Percent Proposal (SDSS PAC Argument, para. 6-9). SDSS PAC also refers to correspondence, media coverage and the evidence of Ms. Peverett to support its submissions that BCTC has misrepresented the BCTC position to the community. It, too, argues that BCTC has provided no “highly persuasive reasons” during the seven week hearing that would support a return to the overhead proposal (SDSS PAC Argument, para. 16-20).

Mr. Campbell also submits that BCTC made a commitment to Tsawwassen residents not to proceed with Option 1 (Campbell Argument, para. 8).

In its Reply to Intervenor Arguments, Sea Breeze states that, in addition to the procedural fairness and legitimate expectation issues raised by TRAHVOL, it was also apparent from the Arguments of TRAHVOL and SDSS PAC that they relied upon BCTC's position throughout the hearing that it would be recommending Option 2. Sea Breeze submits that unfairness may have resulted from BCTC's recommendation of Option 1 if it does not get support for Option 2 from at least 51 percent of the landowners along the ROW (Sea Breeze Reply, para. 88).

BCTC submits that it has neither changed its position, reneged on its commitment not to recommend Option 1 through Tsawwassen, nor dealt with stakeholders in bad faith (BCTC Reply, para. 80-86). It says it met its commitment to not recommend overhead construction through Segment 2 in Tsawwassen by filing its Application seeking underground construction on Segment 2.

BCTC further submits that parties should have been aware both from the Application and from BCTC's responses to information requests that the second best route option would become the preferred route option if Option 2 reached a point where it was not in the public interest (Exhibit B1-1, p. 109; Exhibit B1-11, Holmsen 1.31.6, TRAHVOL 1.92.4 and 1.92.5). BCTC also submits that it presented the route options and considered and measured them against Option 1, the baseline route option. It further argues that it did take steps to correct any impressions left by the media that the ROW would not be used (BCTC Argument, para. 86).

BCTC returns to the issues of bad faith, procedural fairness, abuse of the Commission's process in its Reply (para. 111-120). BCTC says that it is still requesting approval for Option 2 underground construction on Segment 2 through Tsawwassen and while this request is conditional on obtaining a threshold level of underground rights, the request is consistent with its commitment. It explains the reason for the condition on the basis that it alone was recommending Option 2, the Customer Class Group apparently favours Option 1 and the affected landowners express no preference.

BCTC submits that TRAHVOL's positions on the limitation of cross-examination and the need for further cross-examination are without merit for the following reasons:

(a) "TRAHVOL was advised prior to cross-examination of Ms. Peverett that cross-examination would be limited;

(b) TRAHVOL did not ask the Commission to reconsider its decision prior to the commencement of its cross-examination of Ms. Peverett;

(c) TRAHVOL only complained about the time it was allotted at the conclusion of its cross-examination and after an extension of its time by the Chair;

(d) TRAHVOL had full, unlimited opportunity to cross-examine other BCTC witnesses, including BCTC's Policy witness and its VITR Program witness;

(e) TRAHVOL cites no authority for its proposition that the rules of natural justice would be breached if the Commission adopted Option 1;

(f) it has always been clear that the Commission has the jurisdiction to approve Option 1;

(g) the Commission advised TRAHVOL it would be considering Option 1; and

(h) TRAHVOL had the full opportunity to cross-examine and lead evidence on the relative merits of Options 1 and 2 and did so."

On the doctrine of legitimate expectations, BCTC also submits the TRAHVOL position is without merit. It refers to *Apotex* at paragraph 18 and to *Treaty Eight First Nations v. Canada (Attorney General)*, 2003 FCT 782, [2003] 4 C.N.L.R. 349, 236 F.T.R. 65 (QL) at paragraphs 86-87 [*TEFN*] as authorities for the proposition that the doctrine only arises where a party is, or is in a position to bind, the decision maker in question. According to BCTC neither circumstance applies on the facts. Additionally, BCTC argues that when the Commission Panel provided TRAHVOL the opportunity to make submissions on whether the Commission Panel was precluded from considering Option 1, TRAHVOL indicated it would not be taking a contrary position (T8:998-999).

On TRAHVOL's suggestion that BCTC is acting in bad faith and its proposal constitutes an abuse of the Commission's process, BCTC denies it is attempting to use negotiations as a tactic. BCTC submits it will undertake good faith efforts to acquire the rights in question and hopes to obtain the level of support it requires. However, it does not believe proceeding with Option 2 is prudent if the support is not there.

In reply to the SDSS PAC position that it "very reasonably assumed" that BCTC would not recommend Option 1, BCTC points out that the SDSS PAC asked questions of both BCTC Panel 1 and 3 on Option 1 and says if the SDSS PAC assumed the Commission could not approve Option 1, that assumption was unreasonable. Further, it submits the Commission also expressly confirmed that it had the power to approve Option 1 in ruling on TRAHVOL's proposed additions to the Hearing Issues List (T8:996).

BCTC denies that its proposal to exchange overhead for underground rights is insincere as alleged by Mr. Holmsen and Delta and says it has no motivation to conduct negotiations in bad faith. In addition, in response to Delta's submissions that BCTC knew going into the hearing that there was no local support for Option 2 and agreement with the property owners was never a requirement of BCTC's original proposal, BCTC says Delta has not provided references to support such allegations and the evidence is to the contrary.

On the issues of bad faith and abuse of process, the JIESC says such accusations "…should only be raised where the evidence of such conduct is beyond question and where the behaviour of the party raising the issues is beyond reproach." The JIESC submits that the facts do not support such allegations. It argues that BCTC's suggestion that the Commission choose Option 1 if BCTC cannot obtain sufficient support for Option 2 "…is not bad faith or an abuse of process, it is good sense." It further argues that if the residents will not say that pursuing Option 2 at the cost of an extra $14 million, and possibly much more if expropriation is necessary, for the benefit of 102 homes is not an improvement, "…they cannot complain when BCTC and others cannot justify the expenditure." The JIESC also considers TRAHVOL's suggestion that BCTC is acting in an abusive manner and in bad faith when it is acting in a manner forced upon it by the conduct of TRAHVOL's own members to be in itself offensive (JIESC Reply, para. 2-7).

The JIESC submits there would be no breach of the rules of natural justice should the Commission approve BCTC's new proposal. It argues there is no merit to TRAHVOL's argument that BCTC is precluded from presenting Option 1 or that the Commission is somehow estopped from considering BCTC's proposal because BCTC created a legitimate expectation among Tsawwassen residents that it would not proceed with Option 1.

The JIESC distinguishes both *Apotex* and *Mount Sinai* on the basis that both involved the ultimate decision-maker. Both cases dealt with Ministerial discretion, in the case of *Apotex* to enact regulations and in the case of *Mount Sinai* to issue a permit. Like BCTC, the JIESC points out that BCTC is not the decision-maker.

Quite apart from the issue of legitimate expectations, the JIESC says that TRAHVOL cannot argue estoppel, since TRAHVOL cannot establish that it relied on BCTC to its detriment and the facts are to the contrary. The JIESC submits TRAHVOL (JIESC Reply, para. 7):

- "knew precisely what the application was from the start of this proceeding;
- attended these proceedings knowing that this Commission had seven (7) alternative options available to it and that BCTC could not bind the Commission by agreeing not to recommend Option 1. Clearly, even if Option 1 was not available to it, the Commission could have approved Option 2 without an underground section if it decided that was appropriate;
- created the conditions under which it became difficult for BCTC to rationally continue to support Option 2; and
- participated fully as an Intervenor with legal counsel in the entire proceeding which legal counsel cross-examined BCTC's representatives, including BCTC's President and CEO, on the nature and extent of its qualified decision not to recommend Option 1."

In the submission of the JIESC, the Commission can choose any one of Options 1 through 7 through South Delta.

**Commission Determination**

In Section 6, the Commission Panel concludes that the BCTC recommendation for Option 2 cannot be justified, and that BCTC should have recommended Option 1. Nevertheless, the Commission Panel does not accept the submissions of Mr. Holmsen and Delta that the BCTC exchange proposal is insincere. BCTC should have considered the likelihood of support for its proposal, and should have concluded that the likelihood of support was so low that there was no basis for making the proposal. However, in the opinion of the Commission Panel the proposal was sincere and made in good faith, although the likely response was not fully or adequately considered by BCTC.

BCTC's proposal is, as stated in Section 6, an unfortunate attempt to obtain some support for a recommendation that very clearly has none. BCTC should not have made this attempt, but the attempt does not support a claim for abuse of process, procedural unfairness, or contravention of the doctrine of legitimate expectations. The Commission Panel believes that the two cases referred to by TRAHVOL regarding the doctrine of legitimate expectations can be distinguished on the basis that both involved the ultimate decision-maker. In this case, the Commission Panel ensured, by the Hearing Issues List and through consideration of TRAHVOL's two requests regarding Option 1, that Option 1 was within the scope of this proceeding, and would be considered on its merits (T8:996). The Commission Panel accepts the submissions of the JIESC on the issues of bad faith and abuse of process that such accusations should only be raised where the evidence of such conduct is beyond question. That is not the case here.

The Commission Panel does not accept the submissions of TRAHVOL that further cross-examination of Ms. Peverett is now necessary because of the introduction of the 51 Percent Proposal by BCTC. In Section 3.1, the Commission Panel finds that there is an adequate record to approve Option 1. The 51 Percent Proposal does not change the record, nor is it relevant to the Commission Panel's finding as to the adequacy of the record. Therefore, further cross-examination of Ms. Peverett is unnecessary and would not be helpful to the matters to be decided in this proceeding.

The Commission Panel finds that TRAHVOL's request for costs needs to be considered after the filing of a Participant Assistance/Cost Award application by TRAHVOL, and in accordance with the Participant Assistance/Cost Award Guidelines.

### 2.3 Adverse Inferences against Sea Breeze, BC Hydro and BCTC

The issue of an adverse inference has been raised in four instances. In the first, BC Hydro invites the Commission Panel to draw an adverse inference against Sea Breeze from its use of hearsay evidence and its failure to obtain direct evidence from either BPA or Powerex on matters relating to JdF (BC Hydro Reply, para. 8).

BC Hydro submits that Sea Breeze relied on hearsay evidence regarding matters that were significant to the JdF proposal instead of making any effort to adduce direct evidence from Powerex and BPA (BC Hydro Reply, para. 8; T42:7883). BC Hydro argues that Sea Breeze's testimony is not reliable and that not much weight should be given to it (T42:7886-87).

Sea Breeze responds that it was not within its power to produce BPA as a witness because BPA is outside this jurisdiction (T42:7891-92) and that BPA was equally available to either party in this proceeding to call as a witness (T42:7897). With respect to Powerex, Sea Breeze contends that Powerex could not be expected to provide unbiased evidence and therefore no adverse inference can be drawn against Sea Breeze for not calling them as a witness (T42:7897).

In the second instance Sea Breeze submits that the Commission Panel should draw an adverse inference against BCTC for its failure to produce information about the cable tenders requested in Sea Breeze's May 1, 2006 letter to BCTC (Sea Breeze Cable Tender Submission, May 11, 2006, para. 40-41).

BCTC submits that Sea Breeze's request that the Commission Panel draw an adverse inference is "completely unwarranted." It further submits that it has fully answered the undertaking to the Commission Panel to provide a report on the cable tender (BCTC Reply Submissions on Cable Tender, May 16, 2006, p. 3).

In the third instance Delta asks that the Commission draw an adverse inference against BCTC for not producing the ROW agreement through TFN lands despite Delta's request that it do so (Delta Argument, para. 198-199). Delta submits that BCTC is relying on the hearsay evidence of its witnesses regarding BCTC's legal rights to build a new transmission line through TFN lands.

BCTC provides several reasons why no adverse inference should be drawn. BCTC interpreted its undertaking narrowly and consequently did not feel obliged to produce the document but rather, "to reach an accommodation" with Delta (T42A:7928, 7935-36). BCTC believed, on the basis of Delta's testimony, that Delta had the ROW agreement and that, alternatively, it could have been obtained from the Indian Registry (T42A:7925). Nonetheless, BCTC attempted to accommodate Delta by providing its counsel with an opportunity to read the document (T42A:7935). BCTC further submits that its witnesses provided clear, uncontested testimony regarding BCTC's rights to build on TFN lands during cross-examination (T42A:7927-30).

In the fourth instance, Sea Breeze submits that the Commission should draw an adverse inference against BC Hydro for not calling evidence from Powerex (T42:7863). Sea Breeze submits that BC Hydro should have been proactive in providing evidence regarding potential power supply to JdF (T42:7865).

BC Hydro submits that there is no onus on it to provide evidence on all the options to supply power to JdF and notes that Sea Breeze raised the issue of export revenues very late in this proceeding (T42:7872). Regarding the DSBs, BC Hydro considers the record to be uncontradicted and does not believe that BC Hydro needed to call additional evidence to "bolster the facts" (T42:7878-79).

**Commission Determination**

**The Commission Panel concludes that no adverse inferences should be drawn in this proceeding.** The Commission Panel notes that the drawing of an adverse inference is discretionary and finds that, in the cases under consideration, counsel have provided adequate explanations for not calling the evidence in question. While the Commission Panel finds insufficient grounds to draw any adverse inferences, the parties' reliance on hearsay evidence will, in some instances, affect the weight given to that testimony.

In the first case, Sea Breeze chose not to submit information requests to BC Hydro regarding Powerex despite the opportunity afforded by the regulatory schedule (Exhibit A-28), and did not attempt to have a BPA witness appear to support Sea Breeze's testimony. The Commission Panel concludes that, while direct evidence would have added weight to Sea Breeze's testimony, an adverse inference need not be drawn against Sea Breeze.

In the second case, the Commission Panel finds that sufficient cable tender information was filed by BCTC in Exhibit B1-135 to meet its undertaking to the Commission Panel, and concludes that it should not draw an adverse inference against BCTC for failing to meet Sea Breeze's expectations regarding the scope and content of the report.

In the third case, the Commission Panel is concerned about BCTC's narrow interpretation of its undertaking but accepts that BCTC believes that it fulfilled its obligations. The Commission Panel also finds that Delta played a role in the confusion that contributed to the document not being produced. The Commission Panel accepts BCTC's explanation of events and draws no adverse inference against BCTC.

In the final case, the Commission Panel concludes that there was no onus on BC Hydro to call Powerex to strengthen the testimony already on the record regarding DSBs or to call evidence about trade possibilities for JdF, and therefore draws no adverse inference against BC Hydro.

### 2.4 Expansion of the Record

In letters dated May 29, 2006 several parties bring motions to re-open the record. At the beginning of the Oral Phase of Argument a number of the motions were dismissed, and further submissions were heard on the remaining motions. These are dealt with below.

IRAHVOL seeks to have the February 2006 load forecast that is included in Section 3.2.1.1 of BC Hydro's F2007/2008 RRA filed in this proceeding because it shows a significant increase compared to BC Hydro's previous revenue requirements application.

BCTC and BC Hydro opposed the motion. BCTC submits that the February 2006 load forecast was available during the evidentiary phase of this proceeding but IRAHVOL did not ask to have it filed (T41:7562). BCTC also notes that the EENS Study which was filed as Exhibit B1-47 was based on a December 2005 Vancouver Island load forecast which is very similar to the February 2006 forecast (T41:7563). Both BCTC and BC Hydro questioned the probative value of the February 2006 forecast as it does not specifically deal with Vancouver Island (T41:7559, 7563).

**The Commission Panel concludes there is already sufficient evidence on the record regarding the Vancouver Island load forecast and that the February 2006 forecast was available when the record was open. The Commission Panel therefore dismisses the motion.**

IRAHVOL also made a submission regarding Mr. Morris' evidence, but did not seek to re-open the record (T41:7557). **Since IRAHVOL did not seek to reopen the record, there is no need for the Commission Panel to make a decision to dismiss.**

TRAHVOL and SDSS PAC both seek to have an email (which both Intervenors had attached to their Arguments) from the ICNIRP Scientific Secretary included in the record. Although the email was received after the evidentiary phase of the hearing, the inquiry to ICNIRP could have been made earlier. However, BCTC responds to the evidence in its Reply (BCTC Reply, para. 37). **Therefore, the Commission Panel will accept the email, and BCTC's Reply comments concerning it, as part of the record.**

TRAHVOL also asks to have a newspaper article that it had attached to its Reply admitted to the record. As the Chair noted in dismissing SDSS PAC's motion to have two articles admitted, the record would never close, nor could a decision be made, if the record were opened for every such item. **The Commission Panel dismisses TRAHVOL's second motion.**

TRAHVOL and Delta School Board seek to have letters concerning CEC's membership and representation included in the record. TRAHVOL submits that CEC's representative had not made it clear during the hearing that, in this proceeding, CEC represents just a few small businesses rather than the broader commercial customer sector. TRAHVOL seeks to have evidence that includes its letter of May 4, 2006 to CEC and CEC's May 9, 2006 response admitted to the record. Delta School Board asks that the record be re-opened to include its letter dated May 15, 2006 to CEC outlining concerns of misrepresentation and conflict of interest.

**The Commission Panel accepts that the exchange of letters regarding CEC membership occurred as a result of information that became publicly available on April 29, 2006 and that the evidence in question was therefore unavailable during the evidentiary portion of the hearing. The Commission Panel considers the evidence concerning CEC relevant as to weight and will accept the letters as part of the record.**

Delta brings a motion to have BCTC produce the ROW agreement through TFN lands in addition to its motion for an adverse inference concerning non-production of the document (Counsel for Delta letter, May 29, 2006). During the hearing, Delta had requested production of TFN agreements that may be relevant to VITR (T17:3019). The Chair directed BCTC to try to reach some accommodation with Delta and, if unsuccessful, to "bring it back to me" (T17:3018). On April 12, 2006 BCTC advised that it was unable to reach an accommodation with Delta regarding the production of agreements (Exhibit B1-134).

BCTC's testimony was that an additional agreement from TFN is required for VITR and that BC Hydro provided that opinion to BCTC (T17:3016). Further, BCTC confirms that it does have the agreement (T42A:7925). Delta counsel advises that the testimony of the witness for Delta was inaccurate (T22:4172), and that the ROW agreement across TFN lands had not been reviewed by Delta (T42A:7914).

Mr. Holmsen supports Delta's application, submitting that it is very important that the ROW agreement be produced (T42A:7965).

The Commission Panel concludes that Delta could have pursued the matter with the Commission Panel earlier, following the filing of B1-134, as contemplated by the Chair. **Moreover, the Commission Panel finds that there is little probative value in the documents requested because the record concerning the requirement for an additional ROW through TFN lands is adequate. The motion is dismissed.**

## 3.0 BCTC PROJECT SELECTION AND CONSULTATION PROCESS

Questions were raised during the proceeding regarding BCTC's general consideration of project alternatives and route options, the treatment of socioeconomic and other non-financial considerations in the project selection process, BCTC's public consultation process, and BCTC's obligation to consult and accommodate First Nations. This Section of the Decision reviews these issues.

### 3.1 Applicant's Obligation to Study Alternatives

Several Intervenors submit that BCTC's consideration and investigation of alternative technologies, projects, and routes was inadequate and that in some cases BCTC either ignored or was dismissive of alternatives, particularly those proposed by other stakeholders (Sea Breeze Argument, para 10; Delta Argument, para. 4; TRAHVOL Argument, para. 2; Holmsen Argument, p. 2). Sea Breeze submits that in the absence of a proper examination of alternatives, the Commission cannot approve BCTC's CPCN Application (Sea Breeze Argument, para. 9).

TRAHVOL submits that it is difficult to take BCTC at its word that a thorough examination of alternative routes was undertaken, and that it was not predisposed to using the existing ROW (TRAHVOL Argument, para. 134). TRAHVOL submits that there is sufficient evidence to make a determination that both Options 1 and 2 through South Delta are not in the public interest, and also submits that there is insufficient evidence to conclude that Option 4 through South Delta is in the public interest (TRAHVOL Argument, para. 6 and 128). TRAHVOL further submits that there is insufficient evidence to issue a modified CPCN as requested by BCTC in Argument, paragraph 3(d) (TRAHVOL, Argument, para. 6)

Sea Breeze submits that BCTC did not adequately consider JdF as an alternative to VITR, and that as an independent entity responsible for transmission in B.C., BCTC should have proactively and objectively considered all reasonable alternatives for meeting the needs of Vancouver Island (Sea Breeze Argument, para. 54). In Sea Breeze's submission, BCTC's consideration of JdF was "cursory and superficial at best" (Sea Breeze Argument, para. 60).

Mr. Holmsen submits that BCTC has not conducted adequate due diligence and cost estimates for alternative routes and technologies. Moreover, Mr. Holmsen submits that BCTC's cost estimates are excessively biased in favour of Options 1 and 2 through South Delta, and Mr. Holmsen alleges that BCTC and its executives have consistently misled the public with regard to the cost of alternatives, attributes of these alternatives, and feasibility of construction (Holmsen Argument, pp. 2-3).

IRAHVOL also submits that BCTC did not adequately investigate project alternatives and route options. Specifically, IRAHVOL argues that BCTC did not fully investigate and consider the risks of VITR compared to other alternatives, including seismic risks at the ARN Substation and rockslides near the Maracaibo terminal (IRAHVOL Argument, pp. iv-v). IRAHVOL further submits that BCTC did not appropriately consider the visual, socioeconomic, and environmental benefit of the removal of the 138 kV facilities on the Gulf Islands and that BCTC's property expert never visited the Gulf Islands (IRAHVOL Argument p. vi). IRAHVOL submits that a multiple account evaluation should have been included in BCTC's review of all alternatives (IRAHVOL Argument, p. 5).

Delta submits that BCTC undertook a superficial and non-transparent examination of route options and project alternatives, and that it came to this process with a closed mind and determined to follow its agenda only, producing route options with obvious, yet easily corrected, defects. Delta further submits that BCTC has been unresponsive to or dismissive of suggested alternatives, whether project alternative proposed by Sea Breeze such as VIC or JdF, or route alternatives proposed by Delta or Holmsen (Delta Argument, para. 4). Delta further submits that BCTC's approach regarding Options 1 and 2 "…reinforces doubts about the bona fides it has brought to its consideration of VITR alternatives" (Delta Argument, para. 26).

The JIESC submits that BCTC has fully considered all reasonable project alternatives and route options and that it employed an appropriate process to review and evaluate reasonable alternatives. The JIESC suggests that while BCTC has a duty to test all alternatives to a reasonable degree, that does not mean it should do the same level of examination of every possible alternative, but rather it should examine all alternatives only to the extent necessary to determine whether they are viable (JIESC Reply, para. 11).

In response to the concerns raised by TRAHVOL, Mr. Holmsen, IRAHVOL, Delta and Sea Breeze, BCTC submits that the appropriate method of studying alternatives is to start with a wide array of alternatives and then eliminate some as clearly preferable ones emerge. BCTC submits that detailed, and costly, examination only needs to take place where this is necessary to distinguish between alternatives (BCTC Reply, para. 14; Exhibit B1-11, IRAHVOL 1.13.1). BCTC submits that the assessment process that it undertook was appropriate and this assessment has been at a level of detail sufficient for the Commission to reach a determination on this Application (BCTC Reply, para. 22). Finally, BCTC submits Delta not only opposed but actively frustrated BCTC's efforts to investigate alternatives (BCTC Reply, para. 17).

**Commission Determination**

The Commission Panel agrees that the utility has an obligation to conduct an objective and balanced assessment of alternatives, which should include consideration of investigation costs, prior investigation results, and the impacts on all of the utility's stakeholders. The Commission Panel accepts the concept of a staged assessment of alternatives, starting first with a screening assessment of available alternatives and proceeding to successively more detailed investigations only for those alternatives that are considered feasible or for which there is evidence that a more detailed and costly assessment should be undertaken prior to eliminating an alternative completely. However, the utility's decision to limit the investigation of certain alternatives or to eliminate alternatives from further investigation in its selection process should not be influenced by undisclosed and untested preferences for a project. Further, a utility's decision to limit the investigation of alternatives or eliminate alternatives from further investigation should not be influenced by prior commitments, particularly where such commitments will require regulatory approval. The Commission Panel considers factors such as technical infeasibility, significant legal impediments, and high costs may be sufficient reasons to eliminate alternatives during the screening process in order to limit the range of alternatives requiring more detailed assessment. However, the weight of each of these considerations may vary depending upon the planning context and the full range of alternatives under consideration. Further, in the case of a project requiring regulatory approval, an applicant needs to continue to consider and compare other alternatives to the recommended alternative until the evidentiary phase of a regulatory proceeding closes, as such consideration might lead to a change in the applicant's recommended alternative.

The Commission Panel endorses the general approach to project alternatives and route options set forth by BCTC in Exhibit B1-11, IRAHVOL 1.13.1, and concludes that BCTC's investigation of alternatives, with the exception of route options through South Delta, was appropriate. The Commission Panel is concerned that BCTC's investigation of route options through South Delta was influenced by either undisclosed and untested preferences or commitments that were made for reasons that were not disclosed in this proceeding. For similar reasons, the Commission Panel is concerned that BCTC did not follow the evaluation approach in Exhibit B1-11, IRAHVOL 1.13.1 with respect to route options through South Delta. The Commission Panel is also of the view that Option 3 may not have received adequate advance evaluation due primarily to the lack of cooperation from Delta and not the investigation approach of BCTC. These limitations aside, the Commission Panel is able to make determinations regarding Option 3 based on the record in this proceeding. These issues are discussed further in the Commission Panel's detailed review of the VITR route options found in Section 6 of this Decision.

The Commission Panel accepts that the record in this proceeding is adequate to select a project and route option from the alternatives and to conclude that the selected project and route option is in the public interest.

### 3.2 Treatment of Socioeconomic and Other Non-Financial Considerations

During the proceeding, there was some discussion of the appropriate treatment of socioeconomic and other non-financial impacts in BCTC's evaluation of alternatives, and in the Commission Panel's deliberations regarding whether VITR is in the public interest.

The Application contained several tables that ranked alternative technologies and route options using a suite of financial, non-financial and socioeconomic criteria, including cost, reliability, community impacts, environmental effects, First Nations impacts, implementation risk, and regulatory risk (e.g., Exhibit B1-1, Table 4-2, p. 102). For each criterion, BCTC used a seven-point scale and professional judgment to rate the relative performance of each alternative. An overall rating was also developed based on a general assessment of each alternative. In response to BCUC 4.204.0 (Exhibit B1-61), BCTC refined its evaluation framework and added comparisons of other route alternatives and VIC. At the request of the Commission, the revised evaluation framework included an overall ranking of alternatives based on an explicit weighting and aggregation of the ratings for individual evaluation criteria.

In its Application, BCTC indicated that it considered environmental and socioeconomic issues would be dealt with as part of the comprehensive environmental review and approval process that would be required, and indicated it did not intend to submit more detailed information on potential environmental effects as part of its CPCN Application. Specifically, BCTC noted:

> "The VITR Project is subject to detailed environmental assessment and approval processes (including the review and approval of socioeconomic effects) under the British *Columbia Environmental Assessment Act* (BCEAA), the *Canadian Environmental Assessment Act* (CEAA), the US federal National *Environmental Policy Act* (NEPA), and the Washington State *Environmental Policy Act* (SEPA). BCTC has identified the environmental and socio-economic issues raised as part of the public consultation process in this Application. However, given the comprehensive environmental review and approval processes that BCTC must satisfy, BCTC is not submitting detailed information on the potential environmental effects of the Project as part of this Application. BCTC anticipates that any CPCN for the VITR Project will be conditional upon receipt of the permits and regulatory approvals necessary to satisfy Canadian and US environmental assessment and protection requirements" (Exhibit B1-1, p. 75).

Part of IRAHVOL's filed evidence contained a so-called multiple account evaluation of the alternatives (Exhibit C34-6). During the Pre-hearing Conference, IRAHVOL also noted the importance of a multiple account evaluation for the Commission process (T2:247-257). In Argument, IRAHVOL again submits that a multiple account evaluation should have been included in BCTC's review of alternatives (IRAHVOL Argument, p. 5).

In the Pre-hearing Conference, Delta also suggested that environmental and socioeconomic matters are clearly of concern to parties in the proceeding, and there is concern amongst some parties about what is the most appropriate process for dealing with those. Delta suggested there should be an opportunity for evidence and cross-examination on environmental and socioeconomic impacts of the projects, regardless of the outcome, "…rather than relying solely on the somewhat less transparent process within the environmental review process in British Columbia, which deals more with consultation and where you don't have clear mechanisms for challenged cross-examination and things of that nature" (T2:284).

In the Pre-hearing Conference, counsel for Sea Breeze also suggested that "…to the extent that there are material differences between, say, the VIC and/or Juan de Fuca projects and the VITR project in terms of their environmental and/or socioeconomic impact, which I guess represent relative benefits or advantages of one project over the other, or others, from the perspective as we've heard of local residents or other stakeholders for that matter, Sea Breeze submits that the Commission can and should consider the effects of those material differences and take them into account in effectively globally assessing the relative merits of the competing proposals" (T2:290).

The Islands Trust and the Tsawwassen Homeowners Association both agreed with the comments of IRAHVOL and Sea Breeze. The HTG submitted "…whether or not we state that we are in favour of the Panel reviewing socioeconomic and environmental issues, we are in fact basically saying those are issues that the Panel is going to have to consider at least through the aboriginal lens" (T2:293).

In response, BCTC indicated it would strongly prefer that that the issue not be characterized as a matter of Commission jurisdiction, but rather as a determination of what is appropriate in terms of Commission practice and procedure in this particular instance given that there will be a detailed review of a full range of socioeconomic and environmental issues under the BC CEA process (T2:296).

**Commission Determination**

The Commission Panel concurs that socioeconomic and other non-financial considerations may be relevant issues in its determination of the public interest. The Revised Hearing Issues List (Exhibit A-71) included several questions related to the relative socioeconomic impacts of VITR, VIC and JdF, including safety, reliability, health, aesthetic, recreation, habitat, First Nations and construction impacts (e.g., Issues 4.2, 7.2, and 9.3).

Given the comprehensive environmental review and approval processes that BCTC must satisfy, the Commission Panel agrees with BCTC that a detailed examination of socioeconomic impacts is not necessary for the Commission's review, and is potentially duplicative of other regulatory processes. However, a high-level review of the relative socioeconomic impacts of project alternatives is still necessary for the Commission to determine whether a particular project is in the public interest. This review is required for four reasons. First, the Commission Panel must be satisfied that BCTC has reasonably considered other alternatives that may have similar financial costs for ratepayers but lower socioeconomic impacts or better non-financial performance. Second, the Commission Panel may be required to make determinations among projects with similar costs but different kinds of non-financial and socioeconomic impacts. For example, two projects may have similar costs, but one may perform better in terms of environmental impacts while the other performs better in terms of aesthetic impacts. Such considerations may be relevant to the Commission's determination of the overall public interest. Third, the Commission Panel must be assured that the recommended alternative is likely to receive environmental approvals in a timely fashion and that expected compensation or mitigation costs would not render the alternative more costly than another viable alternative. Finally, the Commission Panel could consider modest increases to the project costs in order to reduce socioeconomic impacts and provide other non-financial benefits that may reduce financial or schedule risks associated with the project.

In terms of the form of the evaluation, the Commission Panel agrees with IRAHVOL that some form of multiple account presentation of key socioeconomic and other non-financial impacts can be a useful tool, both during BCTC's selection and consultation process, as well as during the review process before the Commission. The Commission Panel notes that a multiple account evaluation is simply a presentation of different kinds of impacts and the types of impacts and manner in which they are presented may reasonably vary depending upon the context and available information.

The Commission Panel does not consider a detailed examination of each account as necessary in all situations. Further, impacts may reasonably be evaluated using a combination of quantitative inputs and subjective assessments. Performance may also be characterized using summary scales for ease of presentation and comparison. This approach can be very useful for screening and for determining whether more detailed evaluation of certain impacts is required in order to make a final selection among alternatives. To that end, the Commission Panel accepts Table 4-2 found at page 102 of BCTC's Application is a type of multiple account evaluation. The Commission Panel also finds the refinements made in response to BCUC 4.204.0 (Exhibit B1-61) were useful in its deliberations.

The Commission Panel encourages BCTC to consider improvements to its evaluation process for future CPCN Applications. Specifically, as suggested in BCUC 4.204.0 (Exhibit B-61), the Commission Panel considers it important for BCTC to develop and use more explicit definitions of evaluation criteria, and to take special care to eliminate potential double counting among criteria. In addition, while the Commission Panel supports the use of summary scales or scores for representing individual impacts, the Commission Panel also notes the importance of clearly defining scales, whether these are based solely on subjective assessments or on underlying quantitative information. Finally, the Commission Panel considers the presentation of overall scores based on a formal weighting and aggregation of the performance on individual criteria is a useful input for decision making. The Commission Panel acknowledges that the weighting and aggregation of individual impacts may involve judgment and other methodological challenges but still finds this useful in order to understand the proponent's views of the relative importance of different impacts. The Commission Panel also notes that these evaluation techniques can be very useful in consultation processes. The Commission Panel is aware that there is extensive literature on these evaluation techniques and that many similar techniques have been employed by BC Hydro as part of its IEP and water use planning processes.

### 3.3 Public Consultation Process

The Commission Panel considers many of the Intervenor comments regarding BCTC's consideration of alternatives and treatment of socioeconomic and other non-financial considerations are closely related to the public consultation process employed by BCTC.

Section 5 of the Application summarized BCTC's consultation activities related to VITR. In its Application, BCTC states:

> "… [it] has engaged in public consultation on the VITR Project to ensure that all interested parties and potential stakeholders were provided with the opportunity to hear about, gather information, ask questions, and to express any concerns to BCTC about the Project prior to the final project design and the CPCN Application being filed. BCTC's goal was to engage the public in a process of communication and consultation to build a strong body of informed public opinion, leading to a project proposal that meets the technical requirements but that has also been informed by public and First Nations involvement, is cost effective and balances the competing interests of affected stakeholders" (Exhibit B1-1, p. 112).

**Commission Determination**

The Commission Panel notes that the consultation activities of BCTC seemed to centre on its preferred route option, rather than a broad exploration of project alternatives with the public. The Commission Panel accepts that a broad exploration of project alternatives may not have been appropriate with a very general audience (e.g., public open houses) but could have been useful at an early stage with a limited group of opinion leaders and key stakeholders such as the Corporation of Delta. The Commission Panel finds no evidence of such consultations in the Application. Further, the Commission Panel considers that some of the issues explored in the hearing process could have been avoided had BCTC engaged key stakeholders in a more open discussion of project alternatives. In particular, the Commission Panel believes that some of the project alternatives identified during the hearing process could have been identified and evaluated by BCTC prior to the CPCN Application and hearing process.

The Commission Panel also notes that BCTC's consultation process focused almost exclusively on local stakeholders that would be directly affected by the project. While local residents are a key set of stakeholders, the Commission Panel believes that in the case of a large project such as VITR with considerable financial implications for provincial ratepayers, some exploration of general ratepayer perspectives on reliability issues and underground route options should also have been undertaken prior to the CPCN Application and hearing process. For example, BCTC's Transmission Planning Advisory Committee or a similar group may have been a useful forum for BCTC to discuss some of the broader principles and policy issues associated with VITR prior to submitting its CPCN Application.

All route options for VITR, including those proposed by Intervenors in this proceeding, will have adverse impacts, although the form and distribution of impacts may vary across route options. Most of the route options supported by Intervenors, including the preferred route option of TRAHVOL, will have adverse impacts on some residents. The task of approving a project would be much easier if the alternatives included at least one alternative with no adverse impacts. That is not the case. For that reason, providing reliable supply to Vancouver Island may not be possible without some adverse impacts. This must be the starting point and the end point for consideration of route options through South Delta.

BCTC ought to have reached a similar conclusion prior to its commitment to the residents along the ROW in Tsawwassen (Letter from Mr. Costello dated March 17, 2005, Exhibit B1-1, App. D. The letter from Mr. Costello suggests that BCTC anticipated that an alternative route could be found that did not impact residents. However, BCTC should have known by that time in its investigation of alternative routes that no such alternative was available for it to select. Moreover, it should also have anticipated the reaction of the residents along the ROW through Tsawwassen to any use of that ROW. It did not, and in fact seems to have poorly understood the concerns of the residents along the ROW through Tsawwassen even after the conclusion of this proceeding and in Argument.

BCTC acknowledges that all route options have impacts on others, and submits that proponents do not offer an explanation as to why it is more in the public convenience and necessity to benefit people in Tsawwassen, and particularly people who purchased homes with the ROW in place, at the expense of others (BCTC Reply, para. 138). That may be true, but a more significant acknowledgement by BCTC would have been an acknowledgement of the shortcomings of its consultation with the residents of Tsawwassen. Its consultation should have reflected a better understanding of, and sensitivity to, the concerns of the residents along the ROW. For example, Mr. Barrett's hand delivery of the March 17, 2005 letter (Exhibit B1-1, App. D) to Mr. Dunn communicated by action and words much more than BCTC contemplated. This should have been foreseen by BCTC. Further, BCTC's efforts to correct misunderstandings that arose from this communication were either completely absent or were wholly inadequate. BCTC's consultation process did no more than aggravate and antagonize the residents along the ROW. BCTC ought to have fully explained its limited options to the residents along the ROW. The earliest this was done was sometime in May 2005. By that time, residents along the ROW believed that the transmission line would be removed from the existing ROW through Segment 2. This was a fundamental flaw in the consultation and investigation process of BCTC that it should have avoided.

One of the consequences of BCTC's poor understanding of route options and the misunderstanding of residents along the ROW in Tsawwassen was a lack of cooperation by all stakeholder groups in Tsawwassen, particularly TRAHVOL and Delta. All the route options through South Delta, Options 1, 2 and 3, suffer from a lack of meaningful consultation with those most concerned. The evidence in this proceeding regarding Options 1, 2, and 3, particularly regarding the preferences of those most immediately impacted, should have been more fully developed, prior to the Application being filed, than was possible given BCTC's approach to consultation.

The Commission Panel concludes that a better designed and executed consultation process may have resulted in greater cooperation from stakeholders and a fuller investigation of alternatives prior to the Application. Although a better consultation process may have provided more support for the Application and helped to focus the Commission's process, the Commission

Panel also concludes that the issues raised by stakeholders have been adequately explored in this proceeding in order for it to make a determination regarding BCTC's CPCN Application.

### 3.4 First Nations - Obligation to Consult and Accommodate

The HTG, the Sencot'en Alliance and the Songhees First Nation all intervened in the proceedings. TFN appeared at the Tsawwassen Town Hall Meeting and said it did not support Option 4 (T5:653; Exhibit E-59). With the exception of the HTG, none of the First Nations filed argument; nor did any of the First Nations participate in the oral evidentiary phase of the hearing or appear by counsel or by agent during that phase other than for the appearance of Mr. Bak on behalf of TFN at the Tsawwassen Town Hall Meeting.

In Exhibit A-40, the Commission Panel addressed certain requests from the HTG that the Commission Panel characterized as Advance Orders. It concluded that it should only consider those issues arising from the Advance Orders that required consideration at that time. In concluding that the Advance Orders sought by the HTG should not be granted at that time, the Commission Panel stated that it preferred to provide reasons with respect to the matters addressed in Exhibit A-40 with the CPCN Decision and allowed the participants to address both the matters discussed in Exhibit A-40 and other issues raised in the proceedings in argument.

In denying the request by the HTG that the Commission Panel revise the regulatory timetable to establish "a separate, distinct or additional process" for First Nations claims, the Commission Panel noted that "…an obligation to consult and, if necessary, to accommodate may still be borne by BC Hydro and BCTC at the conclusion of this proceeding, and it is open to the HTG in argument to argue that the obligation was not met and that a 'separate, distinct or additional process' was necessary to meet that obligation" (Exhibit A-40, p. 2).

In the Hearing Issues List (Exhibit A-71), the Commission Panel identified the issue of consultation with First Nations in Section 2.3. At T40:7542-7543, the Chair invited counsel for the Applicant and for Intervenors to consider in argument whether BC Hydro met the obligation to consult with First Nations in regard to each of the VITR route options, and whether BC Hydro has an obligation to accommodate First Nations and when does the obligation arise.

The HTG filed Argument in answer to the above questions, as did BCTC, BC Hydro, Delta and CEC.

After stating it continues to rely upon its submissions in Exhibit B1-31, BCTC submits that "…the Crown's obligation to consult First Nations regarding the VITR Project does not need to be satisfied until a final decision is rendered allowing the Project to proceed" (BCTC Argument, para. 102). It argues that the Commission only needs to be satisfied that a process is in place for consultation, and if necessary, accommodation. It further submits that: "Given the consultation that has taken place, and the process that has been established, it is too soon to determine whether any accommodation will be necessary and, if so, what that accommodation might be" (BCTC Argument, para. 102). It concludes its submission with the comment that VITR cannot proceed without an EAC.

Delta and CEC agree with and adopt BCTC's position (Delta Argument, para. 47; CEC Argument, para. 37).

BC Hydro provides its answers to the questions at paragraphs 33-49 of its Argument, ultimately submitting that all obligations to First Nations have been discharged "to the extent appropriate" at this stage. Pursuant to the Key Agreements, as between BCTC and BC Hydro, BC Hydro has the responsibility for consultation with First Nations (Exhibit C6-5, Attachments 5 and 6). BC Hydro submits that based on Supreme Court of Canada case law the duty to consult and, if necessary, accommodate rests with the Crown, not third party project proponents and references *Haida First Nation v. British Columbia (Minister of Forests)*, [2004] 3 S.C.R. 511, 2004 SCC 73 [*Haida First Nation*].

BC Hydro submits that it undertook a lengthy consultation process with numerous First Nations and that close coordination took place and continues to take place between BC Hydro, BCTC and the EAO (BC Hydro Argument, para. 36). BC Hydro notes that its consultation process and the separate EAO process are ongoing and that there will be further consultation opportunities.

It submits that the BCUC: "…can ensure the successful continuation and conclusion of this consultation program by making any CPCN approval subject to the outcome of the assessment being conducted under the *BCEAA* [*B.C. Environmental Assessment Act*]" (BC Hydro Argument, para. 45). BC Hydro also notes that the various First Nations that registered as Intervenors chose not to exercise their full procedural rights during this proceeding (BC Hydro Argument, para. 42-43).

On the issue of accommodation, BC Hydro submits that accommodation does not arise in every case where a duty to consult exists and further that accommodation can take many forms. It also submits that given the uncertainty over route options, it "…is not a reasonable expectation for BC Hydro to have negotiated final and binding right-of-way agreements with the TFN." It further submits that a separate and distinct process is not required by law (BC Hydro Argument, para. 47).

The HTG submits that the Provincial Crown, represented by BCTC and BC Hydro, owe a duty to consult and, if necessary, accommodate First Nations in relation to aboriginal rights and title. It submits that the Crown had not discharged those duties to the HTG and the Chemainus, Lyackson, Halalat, Penelakut, Cowichan and Lake Cowichan First Nations (HTG Argument, para. 1 and 2). It requests that the Commission make the following rulings (HTG Argument, para. 3):

> "(a) it is in the public interest for the Crown to meet its legal duties to First Nations,
>
> (b) the Crown has not met its legal duties to the First Nations that are members of the Hul'qumi'num Treaty Group,
>
> (c) there is no guarantee the Crown will meet its legal duties to First Nations in Environmental Assessments or other processes outside the control of the Commission in regards to this matter,
>
> (d) a certificate of public convenience and necessity should not be granted and the project should not proceed to the next level of authorizations until the Crown has fully discharged its legal duties to the First Nations, and

(e) the Proponent should reimburse the reasonable costs incurred by HTG and the member First Nations in relation to the Commission process."

The HTG urges the Commission to "…reject BCTC's and BC Hydro's narrow and technical interpretations designed to delay any decisions on consultation by the Commission" (HTG Argument, para. 8). The HTG argues that in *Haida First Nation*, the Supreme Court of Canada rejected arguments similar to those made by BCTC at paragraph 102 of its Argument and the Commission should therefore reject the BCTC submission on this issue (HTG Argument, para. 10-14).

Additionally, the HTG submits that the Commission "…ought to be very cautious about placing any faith in the Environmental Assessment process…." firstly, because the Commission has no control over the EA process and secondly, because the present EAO process is very different from that discussed by the Supreme Court of Canada in *Taku River Tlingit v. British Columbia***,** [2004] 3 S.C.R. 550, 2004 S.C.C. 74 *[Taku River]* (HTG Argument, para. 15-17)**.** The HTG submits that since the decision in *Taku River***,** the *EAA* has been amended and there is no longer the requirement for First Nations to have a seat on Project Committees that design and carry out the environmental assessments. The result is that First Nations have a much lesser role, at the discretion of provincial officials.

The HTG submits that the Crown owes a duty to consult in a proactive manner before decisions are made. It argues that "…[a] mere invitation to participate in a public process like the Commission hearing does not necessarily discharge the crown's duty…." and relies upon *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, [2005] 3 S.C.R. 388, 2005 S.C.C. 69 at paragraphs 65 and 66 *[Mikisew Cree]*. It submits that BCTC and BC Hydro have provided some potential evidence of consultation that has or may have taken place in relation to the EAO process, but no such evidence with respect to the Commission process (HTG Argument, para. 18-19).

The HTG further submits that the Commission should take into account the poverty of First Nations, their lack of funding, and their attempts to participate despite serious limitations. It submits that the First Nations have provided evidence of their rights and title and potential infringements and any evaluation of the sufficiency of the information should weigh in favour of the First Nations.

Finally, the HTG submits that the Commission has the legal responsibility to take into account the Constitution of Canada when making decisions (HTG Argument, para. 20-21).

BCTC submits that the HTG has provided no authority to support their "…compartmentalized view of consultation or their submissions on when this process needs to be completed, particularly given that BCTC is expressly prohibited from proceeding with VITR until it has received an environmental approval certificate under the *Environmental Assessment Act.*" BCTC also relies upon the submissions in BC Hydro's Argument and those found at paragraphs 30 to 35 of BC Hydro's Reply (BCTC Reply, para. 207-08).

BC Hydro agrees that the Crown cannot hide behind a Crown Corporation to avoid its legal duties to First Nations, but says there is no evidence of the Crown seeking to do so with respect to VITR. BC Hydro indicates it has undertaken consultations as the Crown's delegate to First Nations on behalf of the Crown and further consultation and, if necessary, accommodation can occur during the EAO process (BC Hydro Reply, para. 30-35).

BC Hydro also submits that the argument that full and final consultation and accommodation on the entire project must be completed as part of the Commission's process is not supported by case law. It submits that in *Taku River*, the Supreme Court of Canada expressly determined that it was not necessary for consultation regarding the entire project to be complete before concluding a particular step in the review process and found that a presumption in favour of ongoing consultation is appropriate *[Taku River, para. 45-46]*. BC Hydro further submits that concerns with respect to future consultations can be resolved by making the CPCN subject to obtaining an EAC.

BC Hydro accepts that there is an onus on the HTG to put forward evidence to demonstrate its rights and an infringement of those rights, but says the HTG has failed to discharge that onus. According to BC Hydro, that failure cannot be justified on the Commission's failure to vary its normal rules and order advance funding. BC Hydro submits that the request for funding must be addressed directly to the Crown for consideration in the context of the overall consultation effort.

On the obligation to consult, the HTG submits that in *Taku River*, the Supreme Court of Canada contemplated that consultation with First Nations be undertaken parallel to the decision being made. It further submits that there is a difference in substance and inquiry between the Commission and EAO process (HTG Reply, para. 2-4).

The HTG also distinguishes the work BC Hydro did with TFN and says similar work was not undertaken with the HTG (HTG Reply, para. 7). In other words, there has been no consultation with the HTG according to the HTG. The HTG says BC Hydro has submitted no such evidence (HTG Reply, para. 13). Further, consultation through Intervenor participation is not consultation in the submission of the HTG (HTG Reply, para. 10).

By letter dated January 10, 2006, the Project Assessment Director of the EAO forwarded to the Commission Secretary a copy of the environmental procedural order (Section 11 Order) for VITR (Exhibit B1-42). Section 14 and section 16 of the Section 11 Order set forth the requirements regarding First Nations consultation. Schedule B of the Section 11 Order identifies all the members of the HTG. By letter dated January 20, 2006, BCTC forwarded the final Terms of Reference for VITR to the Project Assessment Officer that were prepared pursuant to the Section 11 Order. Section 7.10 of the Terms of Reference require BCTC in consultation with First Nations to identify and evaluate potential effects of the Project on Aboriginal interests and, if necessary, to accommodate the effects of the Project on traditional uses and aboriginal interests along the submarine cable corridor and at each of the cable terminals (Exhibit B1-44, Sea Breeze 2.67.2, *Vancouver Island Transmission Reinforcement Project, Approved Terms of Reference for an Environmental Assessment Certificate Application*, pp. 76-77).

During the Oral Phase of Argument, BCTC and BC Hydro submit that in this decision the Commission Panel needs to be satisfied that a process (e.g., the EAO process) is in place for this consultation and, if necessary, accommodation to take place (T41:7650). Further, BCTC and BC Hydro submit that the Commission Panel need not evaluate consultation nor the adequacy of the EAO process regarding the Crown's obligation to consult and, if necessary, accommodate. This submission by BC Hydro needs to be contrasted with submissions by BC Hydro in Exhibit C6-5, which the Commission Panel accepted in Exhibit A-40.

The HTG submits that the EAO will not make changes to the Commission decision, and it follows that consultation at the EAO cannot be adequate consultation if the EAO will not make changes to the Commission decision (T41:7660). Further, if the Commission relies on the EAO process, then the First Nations will never have been consulted relative to the project and the decision being made by the Commission (T41:7662).

**Commission Determination**

The duty to consult with the HTG is accepted by BCTC and BC Hydro. The first issue for consideration by the Commission Panel in this proceeding is whether or not, as BCTC and BC Hydro submit, the Commission need only be satisfied that another process is in place for consultation and, if necessary, accommodation. It follows that if the Commission Panel can rely on the EAO process, then there is no legal duty to consult and accommodate at this stage, that is, for the purposes of the Commission process.

McLachlin C.J. said in the *Haida First Nation* case at paragraph 51:

> "It is open to governments to set up regulatory schemes to address the procedural requirements appropriate to different problems at different stages, thereby strengthening the reconciliation process and reducing recourse to the courts. … It should be observed that, since October 2002, British Columbia has had a Provincial Policy for Consultation with First Nations to direct the terms of provincial ministries' and agencies' operational guidelines. Such a policy, while falling short of a regulatory scheme, may guard against unstructured discretion and provide a guide for decision-makers."

The government has legislated regulatory approvals that must be obtained before VITR proceeds. Pursuant to Section 8 of the EAA, BCTC requires an EAC for VITR. Given the Section 11 Order and the Terms of Reference for VITR, the Commission Panel is satisfied that a process is in place for consultation and, if necessary, accommodation. In the circumstances of VITR, the EAO approval, if granted, will follow sometime after this decision. Through this legislation, the government has ensured that the project will not proceed until consultation and, if necessary, accommodation has also concluded. The Commission Panel concludes that it should not look beyond, and can rely on, this regulatory scheme established by the government.

On this issue, the Commission Panel notes that it is difficult to reconcile the positions stated by BC Hydro in Exhibit C6-5 and in Argument with those stated by BC Hydro during the Oral Phase of Argument. In Exhibit C6-5, BC Hydro stated:

> "To properly apply the public convenience and necessity test, the Commission will require evidence of on-going efforts made by BC Hydro and BCTC to meet concerns expressed by First Nations to the extent practicable, and of any Crown consultation that has occurred and will occur" (Exhibit C6-5, p. 2).

This issue is complicated by the Commission's acceptance of BC Hydro's position in Exhibit C6-5 quoted above. In Exhibit A-40, the Commission Panel said:

> "The Commission Panel concludes that it should only consider those issues arising from the Advance Orders sought by HTG that need to be considered at this time in this proceeding. … However, the issues considered in this letter and other issues raised in the submissions may be interrelated. Therefore, participants may in final argument address both the matters addressed in this letter and other issues raised in submissions."

Therefore, the Commission Panel concludes that it should acknowledge, given the conclusion regarding reliance on the EAO process, that it is not necessary for the Commission to require evidence of on-going efforts made by BC Hydro and BCTC to meet concerns expressed by First Nations as stated in Exhibit A-40 and quoted above.

The Commission Panel concluded in Exhibit A-40 that it is not necessary to alter the Commission processes for consultation with First Nations and stated that the reasons would be provided with this decision.  The Commission Panel now provides the following reason.  Given the conclusion above that the Commission can rely on the EAO process, it necessarily follows that the Commission need not alter its processes for First Nations consultation and, if necessary, accommodation as requested by the HTG application for the Advance Orders.

The Commission Panel notes that the submissions of TFN have been awarded considerable weight with respect to consideration of Option 4.  Similar evidence arising from consultation might also be considered by the Commission in future proceedings.

## 4.0 NEED AND PLANNING CRITERIA

The requirement for additional supply capacity to Vancouver Island arises in part from the inability of the transmission system supplying Vancouver Island to meet certain planning standards following the zero-rating of the existing HVDC system in 2007. This Section of the Decision discusses those standards and the bridging measures that will allow BCTC to meet them between 2007 and the time a new transmission interconnection to Vancouver Island is energized. This Section also examines seismic standards and some of the seismic evidence provided during the proceeding, and discusses the implications for the comparison of project alternatives and route options.

### 4.1 Planning Criteria and Processes

BCTC's planning standards are based on the *Reliability Standards for the Bulk Electric Systems of North America,* which have been established and adopted by NERC and WECC. The NERC/WECC Planning Standards define reliability as the combination of two elements (*NERC/WECC Planning Standards—Definitions*, Exhibit B1-44, Sea Breeze 2.7.6):

(i) "Adequacy: The ability of a bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

(ii) Security: The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits, unanticipated loss of system components, or switching operations."

Three stages of analysis are used to evaluate project and system performance against adequacy standards for worst-case loading conditions. The first stage establishes the capability of the project from an "all-elements-in-service" (N-0) condition. Once a project has been found to meet the N-0 criterion, the analysis proceeds to the second stage, which is the deterministic identification of the loading on system elements under the following conditions: (a) a single-element outage (N-1); (b) a single-element outage when another is already out (N-1-1); and (c) a two-element outage (N-2). Table I, Category B of the NERC/WECC Planning Standards (Exhibit B1-44, Sea Breeze 2.7.6) specifies that there will be no load-shedding or cascading outages under N-1 conditions. An exception to the rule is that the planned or controlled interruption of radial loads and/or network loads supplied by the affected element is allowed, provided there is no impact to the overall security of the interconnected transmission system. Load-shedding is permissible for N-2 conditions, while system performance for three or more elements out-of-service is not broadly evaluated.

Following the second-stage deterministic analysis, a probabilistic evaluation is used to quantitatively compare different projects that meet the deterministic criterion. In connection with the VITR Application, the probabilistic evaluations consisted of several EENS studies. EENS is a reliability index that measures the "expected energy not served" under a specified set of operating conditions, and it is widely used to compare different planning alternatives. Some conclusions from the EENS studies regarding bridging mechanisms and the potential for schedule delays are discussed in Section 4.2, and some conclusions regarding the relative reliability of project alternatives are discussed in Section 7.2. Once a project has satisfied reliability criteria from an adequacy perspective, it may be necessary to evaluate it from a security perspective (T37:7193-7194). A security evaluation, which involves significant computational effort, investigates power system stability following worst-case outages.

BCTC notes that achievement of the planning criteria for Vancouver Island is not strictly required under the NERC standards or under the *Reliability Management System* agreements between WECC and BCTC. The reason is that the Vancouver Island transmission circuits are not interconnected bulk transmission paths, and failures thereon do not affect neighbouring utilities (Exhibit B1-6, BCUC 1.18.1, 1.18.6). Nevertheless, the BCTC planning standard requiring adherence to the N-1 criterion would be in compliance with the *Reliability Management System* agreements.

As noted above, one of the drivers of VITR is the fact that the N-1 criterion will be violated in the winter of 2007/08 after the existing HVDC system is zero-rated for planning purposes in 2007 (Exhibit B1-1, p. 1). Once that zero-rating occurs, the N-1 transmission capacity to Vancouver Island will fall from its current value of 1540 MW - 1300 MW from the two 500 kV circuits and 240 MW from the existing HVDC Pole 2 - to 1300 MW (Exhibit B1-1, pp. 90-91).

Based on BC Hydro's 2004 electricity load forecast, the result will be a significant shortfall (about 300 MW) in firm transmission capacity to Vancouver Island. As illustrated in Figure 4.2 on page 91 of the Application (Exhibit B1-1, the shortfall is expected to grow in subsequent years.

No party opposed the need to reinforce transmission to Vancouver Island.

### 4.2 Schedule and Bridging Mechanisms

BCTC's schedule for VITR calls for the line to be in-service in October 2008, in time for the 2008/09 winter peak. However, as noted previously, a capacity shortfall is expected over the 2007/08 winter peak as a result of the zero-rating of the HVDC system. To bridge the gap between 2007/08 and 2008/09, BCTC developed the bridging measures described in the Application (Exhibit B1-1, pp. 91-92, App. L) and in response to information requests (Exhibit B1-6, BCUC 1.19.4, 1.30.1 and 1.36.1). BCTC states that its bridging mechanisms consist of:

- developing the Transmission Emergency Constraint Management Process, which is a plan developed by BCTC and BC Hydro to maximize supply capacity for dealing with potential Vancouver Island resource deficit situations;
- upgrading the 500 kV circuit rating through real-time measurement;
- making operational reliability improvements to the existing HVDC system through replacement of ageing components and targeted usage;
- supplying the Gulf Islands from the Lower Mainland through the reconstructed 138 kV circuit some time during the winter of 2007/08;
- implementing additional remedial action schemes, including emergency load shedding, to maintain supply/demand balance and system stability;
- implementing contingency plans to speed service restoration if necessary;
- using demand side management, in which one or more customers would voluntarily shed load to restore supply/demand balance.

BCTC states that it will continue to rely on bridging measures to accommodate any delays to VITR, but submits that such measures have declining reliability and are not a preferred or permanent solution to the capacity shortfall on Vancouver Island (BCTC Argument, para. 20). In support of its submission regarding declining reliability, BCTC prepared EENS studies from which the following table is derived (*Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project—Part I: Reliability Improvements due to VITR,* Table 1, Exhibit B1-47, BCUC 3.186.1; Exhibit B1-65, Tables 5, 6, and 7). The studies leading to these results did not account for the bridging measures.

**Table 4-1: Vancouver Island EENS (MW.h/year)**

| Year | No 230 kV, no HVDC | Existing HVDC, no enhancement | Existing HVDC with enhancement | 230 kV, no HVDC | 230 kV with Existing HVDC |
|---|---|---|---|---|---|
| 2007 | 13,839 | 5,655 | 5,002 | N/A | N/A |
| 2008 | 14,998 | 6,667 | 5,858 | 2,870 | 1,140 |
| 2009 | 14,542 | 7,261 | 6,207 | 2,779 | 1,271 |
| 2010 | 16,268 | 8,809 | 7,478 | 2,969 | 1,542 |

BCTC submits that the EENS studies lead to the following conclusions (Exhibit B1-65, p. 3):

- "If the 230 kV line is delayed the existing HVDC system must remain in-service, though this will result in a much higher risk for Vancouver Island power supply than using the 230 kV line.
- Replacing the HVDC Pole 2 reactor at Vancouver Island Terminal and using the old one as an on-site spare (the "enhancement" referred to in the table) is a short-term measure that can improve the availability of the HVDC system and thus Vancouver Island reliability. However, the effect of this enhancement is limited and is only equivalent to delaying deterioration in Vancouver Island power supply reliability by one year."

As noted above, there was no opposition to the need to reinforce the transmission system to Vancouver Island. There was, however, some disagreement over timing requirements. BC Hydro and the JIESC submit that there is considerable urgency in the need for reinforcement (BC Hydro Reply, p. 10; JIESC Argument, para. 93-96). On the other hand, CEC submits that it would be prudent to rely on the bridging measures after 2007/08 if the Commission determined that JdF is a better alternative and if a suitable time frame for completion of the project were established (CEC Argument, p. 6). Sea Breeze argues that the Commission's decision should be driven by the public interest rather than by the urgency argued by BCTC and BC Hydro (Sea Breeze Argument, para. 118).

**Commission Determination**

The Commission Panel concludes that the bridging measures that BCTC has available, including the existing HVDC system, should provide adequate reliability for 2007/08. **The Commission Panel also concludes that, while a one-year delay in the October 2008 in-service date is not likely to cause critical problems, BCTC should move expeditiously to reinforce the power supply to Vancouver Island.**

## 4.3 Seismic Planning Criteria

There was considerable discussion during this proceeding of seismic planning criteria and the differences in seismic stability between the routes that could be used by VITR, VIC, and JdF. BCTC provided significant evidence on seismic considerations in Appendix F of its Application (Exhibit B1-1), Delta provided the evidence of Mr. Laprade (Exhibit C5-6), and Sea Breeze provided the evidence of Mr. Christian (Exhibit C31-20). The general conclusions that the Commission Panel has reached based on the seismic evidence follow. Conclusions related to specific project alternatives and route options are dealt with in Section 7.2.

### 4.3.1 Reliability Implications

To establish the weight to be given to any differences in seismic stability among VITR, VIC, and JdF, and among the different VITR route options, the Commission Panel has reviewed the effect of seismic events on submarine cable forced outage rates and EENS. While the following analysis is more qualitative than quantitative, the Commission Panel accepts that it is sufficiently robust to support its determinations regarding seismic risk. The analysis is based on the VITR circuit, but it is easily extended to VIC and JdF.

At the bottom of page 18 of Exhibit B1-65, BCTC presents a calculation of the FOR for the submarine portion of the proposed 230 kV line based on a failure frequency of once in 10 years and an average repair time of three months (2190 hours). The result is 0.025, which is close to the value of 0.0293 reported in the table on page 18 for single-circuit outages on the existing 500 kV transmission path. To estimate the effect of seismic events on the new submarine cable's FOR, it may be assumed that the cable will definitely be damaged by any event having a return period of 1000 years or longer, but will definitely not be damaged by an event having a shorter return period. The resulting failure probability of once in 1000 years is likely to be a pessimistic estimate given BCTC's comment that it is attempting to get better cable performance than that (T19:3359). Since the cable repair time following a seismic event is expected to be three months (T19:3378-3379) - the same as the repair time used in the original FOR calculation - it follows, upon comparing the 1in 10 non-seismic failure rate with the 1 in 1000 seismic failure rate, that seismic events add only one percent to the FOR value.

To see the effect of seismic vulnerability on EENS, consider a scenario in which an earthquake damages the southern (230 kV) submarine cable. If at least one northern (500 kV) circuit remains operational following the loss of the 230 kV cable, the EENS value is zero because no Vancouver Island load goes unserved. The reason is that the 500 kV cables are normally loaded to 600 MW each and, if one fails, the other is loaded to 1200 MW, so the normal 500 kV operating limit is the same whether one or two 500 kV circuits are available (T10:1580-1583). Consequently, a non-zero EENS value requires a double circuit outage on the 500 kV system. Note that, consistent with the assumption made in BCTC's EENS study (Exhibit B1-65, p. 7), the possibility that an on-Island transmission contingency results in unserved energy is not being considered here.

The simultaneous loss of both 500 kV circuits can result from seismic events or from more "normal" events such as lightning strikes. Given that the material upon which the 500 kV cables rest is more than 30,000 years old and has not failed during many megathrust earthquakes (T21:3831), the Commission Panel accepts that the probability that the northern circuits will suffer seismic damage while the southern circuit is out due to a seismically induced failure is negligibly small. With respect to non-seismic failures of the northern circuits, the table on the top of page 18 of Exhibit B1-65 shows that the common-cause failure of the two 500 kV lines has an FOR of 0.0004, which means that, on average, the 500 kV circuits would be simultaneously out-of-service for 0.0004 × 2190 = 0.876 hours in any expected three-month repair period. Given VITR's 600 MW capacity, it follows that the EENS due to a seismic event is less than 600 MW.h. Factoring in the small annual probability of a seismic failure shows that the EENS due to seismic events is a negligible fraction of the 2,870 MW.h of EENS in the first year of VITR operation (see Table 4.1 above).

**Commission Determination**

Given that the impact of seismic events on the FOR and EENS values for VITR is very small and the statement by BCTC that the route selection has not nearly as much impact on EENS as project capacity differences (T14:2367), it follows that seismic considerations should carry little weight in project or route selection.

Based on the foregoing analysis, the Commission Panel determines that the seismic differences between VITR, JdF, and VIC are too small to affect the choice of project, so the choice can safely and properly be made on other factors. The Commission Panel further determines that, while it is prudent to choose the most seismically stable route from among the options when other factors are roughly equivalent, it is not appropriate to make large capital expenditures to facilitate incremental improvements in seismic stability. In making this determination, the Commission Panel is not diminishing in any way the importance of restoring service to Vancouver Island as quickly as possible after a seismic event or of making prudent and cost-effective design and construction decisions. Finally, the Commission Panel finds that the evidence with respect to the seismic characteristics of the project alternatives and route option is sufficient to allow the Commission Panel to render a decision regarding the VITR Application.

### 4.3.2 Seismic Performance Criteria

Sea Breeze submits that BCTC did not determine what level of risk it would consider appropriate for a submarine cable failure on VITR due to a major seismic event (Sea Breeze Argument, para. 243-251). In Sea Breeze's view, BCTC could not say that the submarine cable for VITR would, with any degree of certainty, survive a 1:1000 seismic event; nor could BCTC say what it considered to be an acceptable level of risk of cable failure in such an event. When certain questions deferred by BCTC's engineering panel were put to its seismic panel, Dr. Atukorala suggested that they could best be answered by BCTC's engineering panel. Sea Breeze submits that, in light of these exchanges with the engineering and seismic panels, there is no evidence before the Commission that BCTC ever actually assessed what level of cable failure risk should be considered acceptable, so it is therefore entirely up to the Commission to make a determination. It further submits that the Commission should, at a minimum, assess VITR against the standards contained in Appendix G to *Guidelines for Ranking Seismic Upgrade Projects* (Exhibit B1-47, Sea Breeze 2.47.5), which would mean that the cables (a) should suffer no damage, and should be restorable in 2 hours, following 1:475 seismic events; (b) may suffer partial damage, but should be restorable within 72 hours, following 1:1000 seismic events; and (c) may suffer severe damage, require extensive repairs or replacement, and cause significant loss of load for events with an annual probability of exceedance of less than 1:1000.

IRAHVOL raises similar concerns, stating that it is extremely difficult to determine what, if any, seismic standard BCTC consistently applied to VITR. IRAHVOL, however, focused more on the fact that Options 1 and 2 of VITR would not be in compliance with IEEE Standard 693, *Recommended Practice for Seismic Design of Substations*, in particular because the VITR transmission path will be a mix of new and existing infrastructure (IRAHVOL Argument, p. 11).

**Commission Determination**

IEEE Standard 693 specifies three seismic qualification categories for equipment: high, moderate, and low. Given a likely PGA of 0.59 g during a 1:2475 event in the VITR area (Exhibit B1-1, App. F, p. 10), the application of IEEE 693 suggests that VITR's substation equipment meets the requirements of the "high" classification. As BCTC points out, the standard is recommended, not mandatory, and is not applicable to the cables (Exhibit B1-17, BCUC 2.124.1).

To achieve a "high" seismic qualification under the IEEE standard, a manufacturer must demonstrate that, under test conditions, its equipment is capable of withstanding certain ground motions. For the purposes of this decision, this can be taken to mean that high-rated equipment is designed and built so that it does not fail under the PGAs associated with 1:2475 events. However, meeting this design and construction standard does not guarantee that the equipment will not fail during an actual event. Nor does knowing the equipment's design capability allow one to readily determine the probability of failure under real-world conditions. That probability depends on, among other things, the equipment's interaction with other infrastructure and the ground motions encountered at the site during an event.

The Commission Panel notes that BCTC has specified that all electrical equipment supplied under the cable tender shall meet the requirements for the "high seismic qualification level" as specified in IEEE 693 (Exhibit B2-58A, p. 7.5-3). Consequently, it accepts BCTC's statement that it is attempting to get better performance than 1:1000 from its cable (T19:3359), and interprets that statement to mean simply that BCTC has based the required qualification level for the VITR cable system on a 1:2475 PGA as suggested by the IEEE standard. Finally, given that BCTC has established seismic performance requirements for the VITR cable system, the Commission Panel does not accept Sea Breeze's view that the Commission must establish what level of risk of cable failure should be considered acceptable. In the Commission Panel's view, design specifications have been established by the appropriate entity.

### 4.3.3 Cable Repair Times

Sea Breeze states that the submarine cable will not be restorable within the 72 hours contemplated by the seismic design criterion included in the reports by Dr. Morgenstern with respect to damage caused by a 1:1000 event (Sea Breeze Argument, para. 272-274).

**Commission Determination**

If a submarine cable is damaged, it is necessary to secure the cable (e.g., prevent further loss of fluid in the case of fluid-filled cables), and to then locate the fault, hire the appropriate vessel, lift the cable, splice it or effect the necessary repairs, and replace it on the sea floor. The time taken to do the work will depend on many factors, including vessel availability and the weather. While the Commission Panel expects that BCTC would carry out the necessary work expeditiously, and that it will continually monitor and update its maintenance practices, it is not reasonable to assume that those tasks could be accomplished within 72 hours. Nor did Sea Breeze propose a mechanism for doing so. Consequently, the Commission Panel sees no reason to impose a specific cable repair time.

### 4.3.4 The Relative and Subjective Nature of BCTC's Risk Assessment

Sea Breeze submits that the Golder's event tree analysis was based on "subjective probabilities", a term defined by the International Geotechnical Commission (Sea Breeze Argument, para. 252-257). It claims, therefore, that the Golder analysis is only applicable to the choice between the routes Golder studied, and is not applicable to a comparison between VITR and JdF. Nevertheless, Sea Breeze goes on to associate probabilities and conditional probabilities of roughly 3 percent in 50 years (or, equivalently, return periods of roughly 1650 years) with certain events, and it submits that these levels are unacceptable (Sea Breeze Argument, para. 256).

One of BCTC's seismic witnesses, Dr. Atukorala, agreed with Sea Breeze that the probabilities were subjective (T20:3652). However, BCTC states that a significant portion of the event tree probabilities are based on non-subjective probabilities, and that the event probabilities were designed to approach the likely risk of cable failure (BCTC Reply, para. 72). BCTC further states that, while the event tree analysis is subjective, a significant portion is based on non-subjective probability. In addition, BCTC submits that it would be extremely difficult to establish "absolute" risks of failure for cables located within geological materials comprising a mixture of solids, liquids, and gases, and which are subject to complex, naturally occurring processes (BCTC Reply, para. 71).

**Commission Determination**

The Commission Panel accepts the submission of Sea Breeze that the probabilities provided are relative, and therefore not strictly applicable to a comparison between projects (as opposed to comparisons between route options for VITR). However, the Commission Panel also accepts BCTC's view that the probabilities were designed to approach actual probabilities. In addition, the Commission Panel notes that there is very limited local data for events that have never occurred (e.g., a 1:2475 earthquake affecting an electric power system on the Lower Mainland), and that the data is limited even globally, which means that "absolute" probabilities would be virtually impossible to develop (T20:3651-3655). The Commission Panel therefore accepts that the probabilities developed by Golder are adequate for the purposes of comparing route options and for assuring the Commission Panel that the seismic risks associated with VITR are small enough that they are not determinative of the project or route selection.

As noted in Section 4.3.1, the reliability impact (as measured by forced outages rates or EENS) of a 1:1000 event is extremely small. It follows that the risks associated with a 1:1650 seismic event are even smaller. The Commission Panel therefore does not agree with Sea Breeze that such an outage probability is unacceptable. Even if a project other than VITR along the approved route could handle a seismic event having double the return period, the EENS and FOR differences would be negligible.

## 5.0 SOCIOECONOMIC IMPACTS

This Section of the Decision first addresses two key health and safety issues raised by Intervenors: the risk of transmission lines falling in the case of a seismic event, and health concerns associated with EMF exposure from both the existing and proposed lines. The impact of transmission lines, and of VITR in particular, on property values is then discussed. The final two parts of this Section consider environmental and archaeological impacts.

### 5.1 Overhead Line Safety

During the hearing, the SDSS PAC raised a concern about the possibility that a downed transmission line on the existing ROW near the high school could create an electrical hazard for students attempting to exit the school during a significant seismic event. SDSS PAC suggested to Dr. Atukorala that the proposed 32 m high transmission structures, if they fell toward the emergency exits, could put conductors on the ground within 9 m of the school (T20:3577). The SDSS PAC submits that, under such conditions, the use of the high school's seven northwest exits would violate the first of BCTC's own Seven Steps to Electrical Safety (Exhibit C41-7), which states: "Stay back at least 10 metres from any fallen power line or exposed underground cable."

In Exhibit B1-83 BCTC stated that steel poles can be designed to limit the affected radius during failure by designing a collapse point in the upper portion of the pole with greater strength in the lower section, so that the circuits will remain suspended with the upper portion of the pole while the lower portion of the pole remains intact. In the SDSS PAC's view, this does not constitute a guarantee of safety (SDSS PAC Argument, para. 25). BCTC confirmed that it was not providing a guarantee when it stated:

> "As far as giving a guarantee, I don't think anyone could get a guarantee, but they will be designed—if there were new overhead structures put there, which we're not proposing, they would be designed such to withstand these kinds of events" (T9:1250-51).

SDSS PAC goes on to state that if the transmission poles and/or circuits are compromised, staff and students may be forced to exit through emergency doors at the far side of the building, and that Delta's Fire Marshall has already alerted the school principal to this recommendation. SDSS PAC also states that it has recently become aware that blocking the emergency exits would not meet provincial school safety practices, nor does it appear to be in keeping with the government's earthquake preparedness plan for schools (SDSS PAC Argument, para. 27-28).

TRAHVOL echoes the concerns expressed by SDSS PAC regarding the possibility of overhead lines falling in close proximity to the exits from the school, and extends the issue to include exits from private homes (TRAHVOL Argument, para. 115(f)).

BCTC submits that the evidence does not support the concern of SDSS PAC and TRAHVOL regarding the seismic integrity of Option 1 because the portion of Tsawwassen where the SDSS is located is not particularly vulnerable to seismic events, overhead transmission lines are not particularly vulnerable to seismic events, the line will be designed to withstand ice and wind loading that generally exceeds seismic forces, and the lines can be designed such that, if they fail, the upper portion remains suspended (BCTC Reply, para. 100).

**Commission Determination**

Based on the evidence before it, the Commission Panel finds that the likelihood of the overhead line near SDSS failing in such a way as to compromise the usability of the school's emergency exits or the exits from private homes is extremely low. **Therefore, costly measures such as removing the line completely from the area are not warranted. However, the Commission Panel notes that there may be cases in which seismic loading can exceed ice/wind loading, and directs BCTC to specifically address this possibility in the design of the overhead segments of VITR.** Further, the Commission Panel suggests that BCTC meet with the appropriate stakeholders to ensure that any valid concerns with respect to the design of the line near the school are addressed.

## 5.2 EMF

Electric and magnetic fields surround any electrical device, including power lines. Health issues raised during this proceeding focused on the magnetic fields associated with ac transmission lines. Therefore, in this Decision the term EMF usually refers to magnetic fields with a frequency of 60 Hz, measured in milligauss (mG).

### 5.2.1 Current EMF Exposure Guidelines

In Canada, there are no national standards limiting residential or occupational exposure to extremely low frequency fields based on health effects. Health Canada monitors the scientific research on EMF and human health and has concluded that "…the scientific evidence is not strong enough to conclude that typical exposures cause health problems" (Exhibit B1-37, p. 27).

ICNIRP is the organization responsible for developing safety guidance for non-ionizing radiation for the World Health Organization, the International Labour Organization and the European Union. ICNIRP monitors the literature related to EMF and publishes independent reviews on the potential adverse health effects, most recently in 2003 (Exhibit B1-37, p. 21). ICNIRP recommends a residential exposure limit of 833 mG and an occupational exposure limit of 4200 mG, but has concluded that there is insufficient evidence to support the development of standards to address concerns about possible health effects from long-term exposure (Exhibit B1-37, p. 27).

The Commission has addressed the issue of health concerns from EMF exposure in several previous decisions (Exhibits A2-1 through A2-7) and concluded that the scientific evidence regarding EMF effects is inconclusive and does not support the theory that power line EMF is a health hazard. In view of the lingering uncertainty and until science is able to provide more definitive evidence, the Commission has previously concluded that a strategy of prudent avoidance and low cost attenuation where possible is appropriate (Exhibit A2-6, p. 4), and has expressed an intention to keep itself apprised of EMF research (Exhibits A2-3, p.5; A2-4, p. 17).

### 5.2.2 BCTC's EMF Practice/Policy

BCTC and BC Hydro monitor the on-going research on EMF exposure, and rely on the recommendations of regulatory and policy-making bodies such as Health Canada and the World Health Organization (Exhibit B1-11, IRAHVOL 1.87.1). BCTC constructs transmission facilities in compliance with the ICNIRP guidelines for EMF exposure levels and, where practical, applies low cost measures to reduce EMF levels such as raising the height of structures and modifying the configuration of the lines (Exhibit B1-11, IRAHVOL 1.78.2).

### 5.2.3 EMF Levels with Existing Line and with VITR Options 1, 2, and 3

BCTC produced a number of different tables and graphs that calculated EMF levels for various scenarios. In particular, BCTC calculated the EMF levels for its existing lines and proposed Option 2 facilities for typical locations in East Ladner, Tsawwassen, Galiano Island, Salt Spring Island and North Cowichan. These levels, shown in Table 3-6 of its Application, were calculated for maximum loading conditions at one metre above the ground at various locations across the ROW according to IEEE Standard 644-1994 (Exhibit B1-1, p.86; Exhibit B1-2; Exhibit B1-17, TRAHVOL 1.25.8).

BCTC also produced EMF calculations for the following scenarios through several segments of the line:

a) existing two 138 kV overhead lines;

b) proposed one existing 138 kV overhead line and one underground 230 kV line;

c) double circuit 230 kV overhead lines on single poles, with one circuit operating at 138 kV (similar to the Arnott to Tsawwassen section); and

d) double circuit 230 kV overhead lines on single poles, with both circuits operating at 230 kV.

These EMF levels are reproduced below for the two VITR segments that generated the most interest and concern during this proceeding:

**Table 5-1: EMF Levels for Segment 2 - Tsawwassen**

| **STAGE** | **East Edge of ROW*** | **Below/Above Conductors** | **West Edge of ROW*** |
|---|---|---|---|
| a) Existing two 138 kV | 25 mG | 59 mG | 18 mG |
| b) One existing 138 kV line and one underground 230 kV line | 22 mG | 194 mG | 5.6 mG |
| c) Double circuit 230 kV lines on single poles with one circuit operating at 138 kV | 26 mG | 149 mG | 15 mG |
| d) Double circuit 230 kV line on single poles ;with both circuits operating at 230kV | 10 mG | 147 mG | 10 mG |

* For locations south of 8th Avenue, the values will be reversed.
Source: Exhibit B1-6 BCUC 1.104.1, as amended by T27:5124

**Table 5-2: EMF Levels for Segment 6 – Salt Spring Island**

| **STAGE** | **South Edge of ROW** | **Below/Above Conductors** | **North Edge of ROW** |
|---|---|---|---|
| a) Existing two 138 kV | 13 mG | 83 mG | 0.6 mG |
| b) One existing 138 kV line and one underground 230 kV line | N/A | N/A | N/A |
| c) Double circuit 230 kV lines on single poles with one circuit operating at 138 kV | 4.6 mG | 181 mG | 5.1 mG |
| d) Double circuit 230 kV line on single poles with both circuits operating at 230kV | 1.4 mG | 188 mG | 1.1 mG |

Source: Exhibit B1-6, BCUC 1.104.3

In addition to raising concerns about the EMF levels on and near the ROW, some Intervenors questioned BCTC's method for calculating the EMF levels. Mr. Holmsen said that he had measured EMF near the existing line through Tsawwassen and found levels to be higher than BCTC's calculations (Exhibit C1-17, BCTC 1.8.1) and a TRAHVOL member also testified that he had measured high levels of EMF in his house (T23:4373-75). TRAHVOL, Mr. Holmsen and SDSS PAC suggested that EMF from underground lines should be measured at ground level.

In response to information requests BCTC calculated EMF levels for the following conditions:

- At ground level for the duct banks through Tsawwassen buried with 1 metre of cover (at peak loads and average loads and at various stages of development) (Exhibit B1-17, TRAHVOL 1.25.8: Exhibit B1-77 Undertaking at T14:2391);
- At ground level for two duct banks through Tsawwassen buried at 1 and 2 metres and at various distances from the centre line at peak loads (Exhibit B1-17, Holmsen 1.26.9);
- At 1 metre above ground for duct banks in the streets of Tsawwassen for 1, 2, and 3 metres of burial for various times and seasons of the year (Exhibit B1-125, Undertaking T28:5343);
- On Galiano Island for two new high capacity 25 kV feeders (Exhibit B1-47, BCUC 3.172.8);
- For present and future stages of VITR (Option 2) at typical levels during the day and night, on weekends and during the week, and for April, July, and September (Exhibit B1-101, Undertaking T15:2499).

BCTC did not calculate EMF profiles for underground cables through Tsawwassen streets as contemplated for Option 3 (T28:5314-16). However, Delta provided evidence that Tsawwassen road allowances are on average about 20 metres wide (T21:3915), which, after adding a typical setback, enables a rough comparison with Option 2 located on a ROW 175 feet (or approximately 53 metres) wide.

The evidence shows that the maximum levels of EMF increase from the present values for all route options directly under/over the line but remain approximately the same or decrease at the edge of the ROW. This is acknowledged in BCTC's Argument (BCTC Argument, para.143) and in various Intervenor Arguments. BCTC argues that none of the levels calculated were greater than the maximum recommended limits set down by ICNIRP at 833 mG.

### 5.2.4 Possible Mitigation Measures

BCTC states that it has selected support structures and optimal conductor configuration that reduce EMF as much as practical (Exhibit B1-1, p. 86; Exhibit B1-2; Exhibit B1-17, Delta 1.12.0). With respect to the cable portion of Option 2, BCTC states that it has designed the duct banks with a delta configuration and positioned the cables close together, to reduce the levels as much as practical (T15:2596-97).

BCTC states that a number of additional measures could be taken to reduce EMF from the underground cables, as outlined in Exhibit B1-111. However, they would result in additional expenditures and may result in the de-rating of the cables (T16:2794-2802). These extra measures include deeper burial, reduced phase spacing, inducing current in the cable shielding sheath, passive shielding loops, and passive shielding plates (Exhibit B1-111). BCTC has calculated the additional cost of deeper burial to be approximately $0.7 million (at $200/metre) for a 2 metre burial and approximately $2.1 million (at $600/metre) for a 3 metre burial. It has calculated that inducing sheath currents could cost an additional $7 million for the addition of two additional cables (to restore lost capacity). Various other forms of shielding could cost an additional $1.4 to $2.0 million (Exhibit B1-111).

BCTC states that it could also take additional measures to reduce EMF levels near the overhead portions of the line, primarily by increasing the height of the poles, although doing so involves trade-offs with the visual impacts (BCTC Argument, para. 127).

### 5.2.5 Intervenor Views

A number of Intervenors including TRAHVOL, Delta, SDSS PAC, IRAHVOL, Holmsen, Campbell and Sea Breeze, as well as many speakers at the Town Hall Meetings, voiced concerns about possible adverse health effects caused by exposure to EMF associated with ac transmission lines. Some argue that, given the scientific uncertainty about health impacts, the safety of transmission line EMF could not be assured and that VITR should therefore not be located on the existing ROW.

Several Intervenors challenge BCTC's use of the ICNIRP guidelines, arguing that the guidelines do not address the levels and duration of EMF exposure encountered by people living close to transmission lines (TRAHVOL Argument para. 64-65 ; Delta Argument, para. 70; SDSS PAC Argument, para. 34) and that reliance on only the ICNIRP guidelines is insufficient (Sea Breeze Argument, para. 219-220). TRAHVOL argues that the international organizations that establish guidelines are not keeping up with the science (TRAHVOL Argument, para. 67). TRAHVOL's expert witness, Dr. Havas, stated that "…it is clear that these outdated [ICNIRP/Health Canada] guidelines need to be reviewed based on recent scientific studies" (Exhibit C3-19, App. A, Evidence of Magda Havas, p. 9).

At TRAHVOL's request Dr. Havas prepared a report for this proceeding in which she reviewed and summarized the literature regarding adverse health effects associated with EMF exposure and other negative health effects from transmission lines (Exhibit C3-19, App. A, Evidence of Magda Havas). Dr. Havas' EMF review was based on her first work in the area, which was published in 2000 and referred to during this proceeding as "Havas 2000" (T27:4984). Dr. Havas did not review the research conducted on EMF exposure since Havas 2000 (T27:5035-37), although she had read some recent studies and reports which she selectively referenced in her testimony.

Dr. Havas disagreed with the conclusions of the IARC, ICNIRP, the National Health Radiological Board, Health Canada and the World Health Organization (T27:5118-20). She suggested that scientific studies and expert panel conclusions that do not conform to the established view "are often delayed or suppressed" (Exhibit C3-34, p. 5; T27:4994-95). However, she was unable to provide evidence to support that allegation or to conclude that the IARC, ICNIRP and National Radiological Protection Board reviews are biased (T27:5045).

Dr. Havas testified that, in her opinion, magnetic fields associated with high voltage transmission lines are a cancer promoter (T27:4982). She acknowledged that the scientific study findings are inconsistent but that, given the possible association between EMF levels and cancer and a number of other health problems, "…power lines should not be built in residential areas, near schools or near play areas unless peak exposures for the entire lifetime of the line can be guaranteed to be under 2 mG (and preferably under 1 mG) at the edge of the [ROW]…" and where prolonged human exposure is likely (Exhibit C3-19, App. A, Evidence of Magda Havas, p. 5).

Several parties advocated use of the precautionary principle, whereby low cost measures would be taken to reduce EMF exposure. On the issue of what constitutes "low cost", TRAHVOL suggested that an amount equal to 4 percent of project costs be used for mitigation measures, as has been done in some California cases (Exhibit C3-51), and that Option 3 could be considered as a mitigation measure (TRAHVOL Argument, para. 73-76).

#### 5.2.6 Dr. Erdreich's Testimony

BCTC's expert witness, Dr. Erdreich, prepared a rebuttal of Dr. Havas's testimony. Dr. Erdreich stated that Dr. Havas did not follow appropriate scientific methods for reaching conclusions from scientific evidence, failed to acknowledge the efforts of independent scientific panels to evaluate the status of scientific research, and presented her conclusions without considering all of the evidence that has become available since her 2000 report (Exhibit B1-37, Evidence of Linda Erdreich, p. 4).

Dr. Erdreich's testimony included a summary of the conclusions of expert panels that have reviewed the scientific research. Dr. Erdreich also reviewed the research published between 2001 and 2005 in order to determine whether the recent findings are consistent with the ICNIRP and IARC conclusions. She concluded that "…the totality of the evidence (including recent studies and research conducted prior to 2001) does not support the idea that exposure to EMF is a cause of leukemia, nervous system tumors, breast cancer or miscarriage." Dr. Erdreich testified that studies have found a weak statistical association between long-term exposure to average magnetic field levels greater than 3-4 mG and childhood leukemia, but the scientific consensus is that there is not a cause-and-effect relationship between magnetic field exposure and childhood leukemia (Exhibit B1-37, Evidence of Linda Erdreich, pp. 45-46).

Dr. Erdreich acknowledged that there is scientific uncertainty concerning the health effects of EMF. She concluded that "[s]cience cannot prove the absence of an effect-but it can determine through extensive testing that, with the continued failure to substantiate the occurrence of adverse effects, the possibility of a real risk becomes very small" (Exhibit B1-37, Evidence of Linda Erdreich, p. 46). In reference to the ICNIRP guidelines, Dr. Erdreich noted that the exposure limits are conservative and incorporate safety factors to account for potential sources of uncertainty (Exhibit B1-37, Evidence of Linda Erdreich, p. 27).

**Commission Determination**

The Commission Panel concludes that the EMF exposure guidelines established by organizations such as the World Health Organization, ICNIRP, and Health Canada provide a relevant and useful reference point for considering the safety of EMF levels from the existing transmission lines and the proposed VITR. The Commission Panel notes that the current guidelines are based on broad reviews of the scientific studies and that the absence of a guideline for long-term exposure is based on reviews that have concluded that the scientific research does not support the need for such a guideline.

The Commission Panel also accepts that a standardized methodology for calculating and comparing EMF levels is necessary and that the IEEE Standard 644-1994 used by BCTC is the appropriate standard for these calculations. The Commission Panel accepts BCTC's calculations of the EMF profiles and finds that the EMF levels associated with the existing and proposed lines are well below the established exposure guidelines.

The Commission Panel recognizes that EMF levels in the homes and yards along the ROW may be higher than average but does not accept TRAHVOL's characterization of them as uniquely high, given the number of transmission lines located in residential areas of the Lower Mainland.

The Commission Panel notes that the residents living along the ROW purchased their homes after the existing lines were installed and that the benefits of large lots and/or low prices were weighed against the presence of the transmission lines (Exhibit C3-19, App. A, Affidavits). The Commission Panel recognizes that individual residents living along the ROW will have different exposure levels depending on the distance from the lines to their homes and on the relative amount of time spent in the houses and backyards. However, because VITR will reduce EMF levels at the edge of the ROW in many locations, some residents will experience reduced overall exposure with VITR relative to the existing lines.

The Commission Panel acknowledges that the EMF-related health concerns described by Intervenors living near the existing transmission line may be causing stress and anxiety in some residents, but concludes that the science does not support their fears. The Commission Panel finds Dr. Havas's evidence to be selective and her opinions unconvincing. Dr. Havas conducted one comprehensive study of the pre-2000 research but did not review the more recent scientific research and therefore could not support her position that recent scientific research indicated a need for lower exposure guidelines. **In the absence of convincing new evidence that indicates that change is warranted and/or imminent, the Commission Panel concludes that it should not impose lower EMF exposure standards on VITR.**

The Commission Panel finds that terms such as "the precautionary principle" and "prudent avoidance" are open to a range of interpretations, and is therefore not adopting either term in its determinations. Consistent with previous Commission decisions, the Commission Panel supports efforts to reduce EMF levels where mitigation costs are not significant or where the benefits clearly exceed the cost of mitigation measures. In this proceeding, the evidence does not show that the additional reductions attainable through shielding, deeper burial or taller poles would have positive health impacts and therefore the Commission Panel concludes that the costs of additional mitigation measures to further reduce EMF exposure along the existing ROW are not justified. Mitigation measures may reduce the level of concern and worry experienced by nearby residents. However, while this benefit is not insignificant, **the Commission Panel concludes that it does not warrant actions beyond the very low cost measures that BCTC**

**has included in its VITR design.**

Regarding TRAHVOL's suggestion that a different VITR route through Tsawwassen streets would mitigate EMF exposure, the Commission Panel notes that an ac transmission line will create EMF regardless of its location so any impact will simply be transferred to a different location. In the case of Option 3 a different, and possibly larger, group of Tsawwassen residents would experience increased EMF exposure. Further, the Commission Panel notes residents along a new ROW would have purchased their properties prior to the new lines and would therefore not have benefited from the combination of lower prices and larger lot sizes experienced by the majority of homeowners along the current ROW.

In several previous decisions the Commission indicated that it would monitor the science associated with EMF health effects. Given the limited capacity of the Commission to monitor science on a regular basis, and given the existing efforts by BCTC to monitor this issue, **the Commission Panel directs BCTC to file a public report with the Commission every two years, or sooner if there are major developments in the field, that summarizes the latest results of EMF risk assessments and any changes in guidelines developed by the World Health Organization, ICNIRP, Health Canada and others where relevant.** This directive is intended to help the Commission fulfill its commitment to monitor the science and will allow residents to keep abreast of major developments in the field, hopefully alleviating some of the anxiety they may feel. The Commission Panel also expects the reports will provide a common foundation for evaluating any EMF issues associated with future transmission projects in the province.

### 5.3 Property Value Impacts

Evidence regarding the effects on property values of transmission lines in general, and VITR in particular, was provided by several parties. This Section first considers the evidence related to the reasons why transmission lines can affect property values. It then reviews the potential impact of replacing BCTC's existing lines with VITR.

### 5.3.1 How Transmission Lines Affect Property Values

Delta's expert witness, Dr. Gregory, filed evidence on how transmission lines can affect property values. He reviewed the literature on impacts of electric power lines on property values, and found that from 1979 on, competent studies have been conducted (Exhibit C5-6, Evidence of Robin Gregory, para. A5). The literature identifies several reasons why transmission lines might affect property values, including possible EMF-related health effects, visual impact, noise, ecological effects, and construction-related impacts (Exhibit C5-6, Evidence of Robin Gregory, para. A6).

Based on his review of the literature, Dr. Gregory concluded that there was a likely decline in the value of properties adjacent to high-voltage transmission lines of about 5 to 10 percent and that the fear of EMF-related health effects plays a major role in this decline. He also notes a 2004 study in which the authors conclude that property value reductions varied from 1 to 20 percent, with a base case value of 10 percent that was half due to EMF effects and half due to non-EMF effects (Exhibit C5-6, Evidence of Robin Gregory, para. A8).

Dr. Gregory explained that there can be discrepancies between public and expert views of risks, that stigma refers to an unusually high level of fear based on public perceptions of risks, and that it can occur even in the absence of demonstrated physical impacts (Exhibit C5-6, Evidence of Robin Gregory, para. A7). Therefore, although the scientific evidence may not support a conclusion that transmission lines create EMF-related health problems, the presence of EMF may create stigma.

Dr. Gregory submitted that stigma is a social construct, relating to risk perceptions at a particular time and place, and that it can vary over time and by market. Perceptions of risk can be affected by media coverage, new research results, recent events or other factors (Exhibit C5-10, BCTC 1.19.3). Stigma will generally increase when there is widespread concern in the media, especially if the coverage is one-sided or focused on inflammatory evidence (T23:4283).

Mr. Dybvig, who appeared for BCTC, took a different approach from Dr. Gregory and reached different conclusions. He disagreed with Dr. Gregory's reliance on attitudinal studies, which he considers inferior to direct market evidence (Exhibit B1-37, Evidence of Larry Dybvig, p. 50). He did not separately address EMF impacts and focused instead on visual impacts and actual sales data. He stated that the ability to see overhead poles is a primary predictor of negative value effects, that there is positive effect when lines are put underground and that the average effect of converting from old-style wood poles to fewer but taller steel poles is a modest increase in the value for properties containing the ROW (Exhibit B1-37, Evidence of Larry Dybvig, pp. 41 and 43).

Mr. Campbell challenges Mr. Dybvig's analysis and his conclusions, noting that Mr. Dybvig had neglected to mention a study that discussed a situation in California where transmission lines crossing residential properties were upgraded (Campbell Argument, para. 11-12).

### 5.3.2 The Impact of VITR on Property Values

BCTC submitted that there would be an improvement in property values if underground construction were used on the Tsawwassen ROW (Exhibit B1-1, App. R, p. 4) because of the reduction in both visual impacts and EMF levels at the edge of the ROW (Exhibit B1.6, BCUC 1.41.2).

Mr. Dybvig concluded that an overhead VITR would, on average, have a modest positive impact on the value of properties on the ROW but that there would be site-specific impacts on property values depending on the locations of the new poles and their visibility (Exhibit B1-37, Evidence of Larry Dybvig, pp. 41, 46). Mr. Dybvig testified that the impact of a change in the capacity of the line, as is the case for VITR, would at most be a modest negative value effect, and that any effect would diminish or disappear over time (Exhibit B1-37, Evidence of Larry Dybvig, p. 48; T24:4617-19).

Dr. Gregory submitted that VITR is likely to negatively impact the value of properties adjacent to the line for reasons that include EMF fears and asymmetry of benefits (Exhibit C5-6, Evidence of Robin Gregory, para. A10). However, he was unable to quantify the impact without further study and better information (Exhibit C5-10, BCTC 1.19.6).

Maracaibo submitted that the ROW on Salt Spring Island has had, and will continue to have, a negative effect on the value of properties along the ROW (Exhibits C25-3, C25-8), and provided evidence that the value of lots fronting on the ROW had increased much less than had the other lots since 1980 (Exhibit C 25-6, BCTC 1.5.2). It appears that Maracaibo may have been referring to the dc ROW in its analysis because its witness later stated that there is, at most, one resident along the ac ROW (T22:4096). Maracaibo submitted that VITR would have an additional negative impact on property values because its thicker cables and more closely spaced poles, as well as the removal of some trees, would make the new line more visible (Exhibit C25-8).

TRAHVOL's Property Impact Panel included an employee of the BCAA. The BCAA has historically used an adjustment factor of 10 percent for properties, such as those on the Tsawwassen ROW, that are encumbered with a transmission line. In light of the publicity, controversy and uncertainty associated with VITR, the BCAA decided to reassess properties along the Tsawwassen ROW. Based on its analysis, the BCAA concluded that 20 percent was a reasonable estimate of the impact, as of July 1, 2005 of the transmission line on the Tsawwassen properties containing the ROW (Exhibit C3-41, para. 4-13).

TRAHVOL's Property Impact Panel presented an analysis of property assessment data and submitted that the reduced assessments for properties along the ROW for 2006 reflected a property value loss associated with VITR. A TRAHVOL witness testified that the announcement in July 2005 of the VITR underground route option through Tsawwassen is the only factor which reasonably accounts for the change in the power line adjustment between the 2005 and 2006 assessments, and that BCAA's reassessments followed the announcement of Option 2 (Exhibit C3-40, para. 12; T23:4428).

Mr. Holmsen also submitted evidence showing that assessment for ROW-encumbered properties had declined in 2006 and increased only slightly for properties adjacent to the ROW, while other property assessments in Tsawwassen had increased by 12.6 percent (Exhibit C1-25).

Mr. Dybvig testified that he did not believe that the assessed values for the properties along the ROW accurately reflect the market value trend for those properties in recent years (T24:4574). He submitted that assessment data is prepared for property tax purposes, whereas his analysis considered properties that had actually sold or been listed recently in the local market (T24:4575). His analysis did not find any evidence that the value of properties along the ROW had fallen at all (T24:4571).

TRAHVOL does not question the fact that the residents had purchased their properties knowing that there were transmission lines on them, but argues that they were not fully informed purchasers (TRAHVOL Reply, para. 14). TRAHVOL also argues that the record is clear that residents knew little or nothing of the possible risks associated with EMF (TRAHVOL Reply, para. 14). However, some of the affidavits submitted by TRAHVOL make it clear that some residents were aware of the EMF concerns but purchased their properties because of the price or the large yard (Exhibit C3-19, App. A, Affidavits).

IRAHVOL submits that the proposed changes to the transmission lines will further adversely impact property values for which BCTC should provide compensation. It also submits that more tower sites and/or higher transmission towers near Maracaibo Estates and other locations in the Gulf Islands will diminish property values (IRAHVOL Argument, p. 60).

**Commission Determination**

The Commission Panel concludes that EMF concerns can result in stigma which can, in turn, negatively affect property values. It also accepts that the presence of a transmission line on a property reduces its value and that this has been the case for many years. As Dr. Gregory testified, studies on the impact of transmission lines on property values have been conducted for about 30 years.

VITR does not involve the addition of a transmission line in an area where there is currently no line, but instead involves the replacement of an existing line. Because all but one of the Tsawwassen and Maracaibo property owners purchased their properties after the existing lines were installed, the current owners realized the benefit of the reduced cost of their properties when they purchased them. The Commission Panel also finds that any evidence that the properties owners were not informed purchasers is outweighed by the ROW agreements that are registered against their property titles.

**The Commission Panel concludes that the evidence of the impacts of VITR on property values in Tsawwassen and the Gulf Islands supports a finding that the approved VITR will have no significant incremental impact on average property values over the long-term. If there are any short-term impacts, the Commission Panel concludes that they will decline over time and should be afforded little or no weight in this Decision.**

The evidence of TRAHVOL's Property Impacts Panel centred on property assessments that were adjusted downward to reflect the controversy surrounding BCTC's proposal to build Option 2 through South Delta. The Commission Panel concludes that the reassessments are related to an option that it is not approving and, moreover, that the assessments do not accurately reflect property sales values.

### 5.4 Environmental Assessment

In its description of the evaluation process for project alternatives, BCTC states that one of the primary considerations is an assessment of environmental effects (Exhibit B1-11, IRAHVOL 1.13.1; BCTC Argument, para. 23). Project alternatives are removed from further consideration at this level if a large deficiency or if an effect that cannot be mitigated is encountered. Detailed studies and analysis only take place to the extent required to arrive at a final preferred route option. Once a preferred solution is determined, further refinements such as alignment adjustments are still considered during environmental assessment.

BCTC performed a comparison of the effects on marine habitat, terrestrial habitat, parks and recreational resources, and aesthetic values of the VITR route options through South Delta against one another, as well as VITR (with Option 2 through South Delta) against VIC (Exhibit B1-61, BCUC 4.204.0; Exhibit B1-68). BCTC's assessment was that VITR has less effect on marine habitats than VIC, which has more than twice the length of marine corridor than VITR and requires an entirely new route not presently occupied by high-voltage cables (Exhibit B1-61, BCUC 4.204.2). In addition, VIC passes through a greater length of the area proposed by Parks Canada for a National Marine Conservation Area south of Active Pass and Salt Spring Island to the U.S. border. HVDC alternatives suggested to bypass the Gulf Islands would also create new corridors and pass through or adjacent to protected marine habitats. They would also require the development of new cable landing sites, including terminal stations and chaseways.

With respect to the terrestrial habitat, BCTC observes that VITR would be entirely within an existing, previously disturbed terrestrial corridor, and is therefore expected to have the least potential effects on freshwater and terrestrial resources and habitats, relative to other alternatives. It will have little, if any, additional permanent impacts compared to the existing facilities that it will replace. BCTC also observes that VIC would require new excavation for a distance of more than 50 kilometres, including traversing underground cables through wetlands, crossings of the Serpentine and Nicomekl Rivers and their protective dykes, plus the Serpentine Fen Bird Sanctuary, all of which are within the Boundary Bay Wildlife Management Area. Furthermore, BCTC submits that each of the HVDC Light® alternatives would require some new corridor, and a relatively large amount of excavation compared to VITR.

BCTC states that VITR will have little permanent effect on existing parks and recreational resources because although the existing corridor crosses parks, tennis courts and walking trails, little of this will change by replacing the existing overhead lines. On the other hand, BCTC claims VIC would create no changes to the existing corridor, but would have effects on recreational resources in South Surrey and on the Saanich Peninsula including the Serpentine Fen Bird Sanctuary and Nature Trails Park and the Mount Work Regional Park.

BCTC's assessment of the best performing alternative from an aesthetic perspective is VITR with Option 2 through Segment 2 and the option of burying a portion of the 230 kV ac line in developed areas on the Gulf Islands. In both of these segments, there would be improved aesthetics by removing the existing wood pole H-frame lines and installing underground circuits. All of the HVDC Light® alternatives would have no effect on the existing corridor and would require development of new corridors and the construction of two large converter stations. All of them would also require development of new cable terminal stations or landing sites.

Delta submits that the severity of the environmental concerns suggested by BCTC for Option 4 through South Delta, as proposed by Mr. Laprade (Exhibit C5-10, BCTC 1.7.1), is not supported by the evidence (Delta Argument, para. 208). BCTC replies that whether the loss of eel-grass and other environmental issues associated with a modified Option 4 could be mitigated or not, or whether these impacts would be acceptable to the relevant provincial and federal agencies does not change the fact that these impacts would be greater than for Options 1, 2 and 3 (BCTC Reply, para. 141). Mr. Holmsen advances the notion that Option 1 has no less environmental impact than a Highway 17 option (Option 4) (Holmsen Reply, para. 16).

Sea Breeze claims that because VITR uses fluid-filled cables, this presents a significant environmental risk in the event of a fluid leak. Sea Breeze observes that VITR traverses a substantial area of eel-grass, and claims BCTC has made inadequate provision for environmental mitigation (Sea Breeze Argument, para. 189, 235). Sea Breeze also proposes that JdF is the most environmentally friendly alternative to meet the Vancouver Island reliable transmission capacity needs because JdF, like VIC, does not use fluid-filled cables and avoids significant eel-grass areas. Sea Breeze states that it would employ HDD where necessary in the construction of JdF in order to mitigate environmental impact.

BCTC states that the probability of fluid leaks from the cable is low, and state-of-art leak detection and flow-limiting systems will be specified to alert system operators to presence of a leak and lower fluid pressure to reduce any leakage until repairs can be completed. BCTC further submits that the fluid will be specified to have good biodegradability characteristics (Exhibit B1-39, p. 9). While good biodegradability characteristics do not guarantee that there would be zero impact on sea life in the vicinity of a leak, BCTC submits that the use of such biodegradable fluids minimizes any impacts in the event of a leak (Exhibit B1-44, BCUC 3.187.5).

The JIESC believes that Options 4, 5, 6 and 7 are all infeasible for various reasons (JIESC Argument, para. 75).

**Commission Determination**

The Commission Panel concludes that BCTC's evaluation process has accurately assessed that some route options for VITR would not be precluded from construction based on insurmountable environmental impacts. Specifically, the Commission Panel finds that Options 1, 2 and 3 through South Delta have the lowest environmental impact of all the feasible route options considered, and that all three of these route options are environmentally acceptable. Option 1 through South Delta and the proposed configuration on the Gulf Islands are improvements on the existing aesthetics because the existing wood pole H-frame lines are removed and replaced with a narrow profile double-circuit line in the center of the ROW. The Commission Panel makes its determination with respect to the Gulf Islands preferred route option in Section 6.3.

The Commission Panel accepts that the environmental impacts associated with VIC are greater than those for VITR with Options 1, 2 or 3 for Segment 2. The evidentiary record on the environmental characteristics of JdF is not sufficiently complete to allow a full comparison against either VITR or VIC, or to determine whether or not JdF will cause insurmountable environmental impacts. However, the Commission Panel does not consider the environmental characteristics of JdF determinative in this Decision.

### 5.5 Archaeological Assessment

The archaeological concerns addressed during the hearing focused primarily on the effects of Option 4 through South Delta. BCTC's evaluation was that Option 4 through South Delta had a potential fatal flaw in that in addition to passing through known archaeological sites, there was a high chance of encountering previously undiscovered archaeological resources or human remains on the route, thereby triggering project rejection or massive costs to excavate, protect or relocate artifacts and human remains (Exhibit B1-61, BCUC 4.204.2; Exhibit B1-57, Attachment 1, p. iii). In support of its claim, BCTC entered into evidence a portion of a communication from the Archaeological Branch of the Ministry of Environment:

> "The Archaeological Branch supports the recommendation that Route 4 not be selected over the preferred Option 2 route presented at their meetings",

and,

> "If the findings of the AIA support the AOA, as is likely, refusal to issue an alteration permit to BCTC to allow activities will -- which would disturb such a major part is a real possibility" (T10:1490).

BCOAPO, CEC, and TFN all state that they shared these concerns over Option 4 through South Delta (BCOAPO Argument, p. 8; CEC Argument, para. 207; Exhibit E-59).

Several Intervenors point out that BCTC's own archaeological assessment (Exhibit B1-57, Attachments 1, 2) identified that Option 2 through South Delta would impact a greater area with archaeological potential than Option 4 (Holmsen Argument, p. 8; Delta Argument, para. 193). BCTC addresses these concerns by again claiming that in addition to having more known archaeological sites, there is a "much higher probability" of identifying more new archaeological sites along the route for Option 4 compared to Option 2 (BCTC Argument, para. 161-163).

**Commission Determination**

The Commission Panel concurs with BCTC's assessment that Option 4 through South Delta has the highest probability of negative project consequences as a result of encountering both known and previously undiscovered archaeological sites once construction begins, and further concludes that Options 1, 2, and 3 can be reasonably expected to avoid such negative consequences.

# 6.0 VITR ROUTE OPTIONS

This Section of the Decision first addresses issues that affect one or more route options. The first Section addresses general concerns about transmission lines in residential properties or near schools. The second Section deals with the various route options through South Delta, including construction impacts associated with Options 1, 2 and 3. The remaining Sections consider route options across the Gulf Islands, the cost of the overhead options and Stage 2 preparatory work, the ROW agreements, and restoration costs.

## 6.1 Transmission Lines in Residential Properties and Near Schools

The subject of high voltage power lines in residential properties surfaced on numerous occasions during the proceeding. The issues that this subject matter relates to include: EMF concerns, safety, aesthetics, impact on property values, access to the ROW, restrictions on the use of property and uniqueness of the Tsawwassen ROW. This Section summarizes different perspectives presented on this topic and explains the finding of the Commission Panel.

### 6.1.1 Intervenor Concerns Regarding Transmission Line Routing

TRAHVOL's purpose and stated objective is to first prevent upgrades on the existing ROW and next to remove the existing lines from the ROW. The focus of TRAHVOL's concerns in this proceeding relate to EMF and associated health effects, restrictions regarding the use of the ROW, property value impacts, and construction impacts. During this proceeding, TRAHVOL's concerns were most intensely expressed during the presentations at the Town Hall Meetings and by Ms. Broadfoot in her opening statement when she said: "I want to be clear that we will not cooperate with this plan and will continue with litigation and further action" (Exhibit C3-45, p. 5). Mr. Campbell said: "I submit that options 1 and 2 as proposed by BCTC would impose undue hardship on homeowners along the right of way" (Campbell Argument, para. 8). The Commission Panel notes the submissions of SDSS PAC that the life of even one child, "…put at risk necessarily because of location of their school, is more important than any of these other issues, especially in light of the existence of alternative routes and technologies that would keep these very children out of harm's way" (SSDSS PAC Argument, para. 11).

The Islands Trust believes that a 21st century solution to the current transmission problem is a solution which provides the safest, healthiest and least environmentally disruptive transmission, particularly if that alternative offers the possibility of restoring the province's natural aesthetic beauty along the existing transmission corridor (Islands Trust Argument, para. 6). Similarly, Mr. Campbell submits that in Canada, in the 21st century, we should be holding ourselves to a higher standard than we did fifty years ago, not a lower one (Campbell Argument, para. 7). He further argues that transmission infrastructure does not belong in privately owned residential backyards and that it is fundamentally incompatible with densely populated residential areas when other viable, affordable route options are available (Campbell Reply, para. 1).

BCTC notes that all things being equal, if BCTC had both a non-residential and a residential option, BCTC might elect to choose the non-residential option because it would be less disruptive (T9:1269, 1306). However, dealing with economic realities BCTC submits that transmission lines are not an anomaly on the existing ROW in Tsawwassen and the Southern Gulf Islands. The nature of BC's geography, and the cost associated with new transmission facilities, simply does not allow for the luxury of abandoning the existing ROW (BCTC Reply, para. 8-9).

Delta submits high voltage electric transmission lines should be recognized as a land use that is fundamentally incompatible with residential uses, and as such, should be located in utility or infrastructure corridors that are separate from residential and other areas with non-compatible uses (Delta Argument, para. 8). Delta further suggests the Commission Panel should begin its deliberations about VITR route options by asking whether, in this day and age, the existing Tsawwassen ROW is an appropriate location for a high voltage transmission facility (Delta Argument, para. 49). Finally, Delta highlights a summary of current "best practices" for electric utilities and regulators found in the article from *Transmission Watch* introduced by Sea Breeze (Exhibit B2-45). The article notes how transmission planning and regulatory practices are changing to address, among other things, community opposition and local concerns about transmission lines. This may entail the use of higher cost, non-traditional approaches to transmission line siting, such as undergrounding, use of alternative technologies, and changes to routes to avoid sensitive areas (Exhibit B2-45, pp. 10-16).

BCOAPO argues that opposition of Tsawwassen residents and groups, such as TRAHVOL and the SDSS PAC, is not so much to VITR as it is to the very existence of the ROW through their properties. BCOAPO further submits the fundamental approach of these Intervenors was that any alternative to serve Vancouver Island that did not involve the use of the existing ROW was preferable, regardless of costs to ratepayers – a classic case of the NIMBY phenomenon (BCOAPO Argument, p. 3).

TRAHVOL does not believe that it is in the public interest to put high voltage transmission lines in the backyards of any residents in British Columbia. For that reason, TRAHVOL has consistently advocated for a proper examination of route options that would avoid placing lines directly over or under residential properties (TRAHVOL Reply, para. 11).

With regard to the reality of the existing ROW, recognized as a very significant public asset by BCTC, TRAHVOL first states that clearly if the ROW did not exist it would not be in the public interest to put 230 kV transmission lines directly in 150 private backyards. It then rationalizes that such a project cannot become in the public interest simply because there is an existing ROW and urges the Commission Panel to question whether, in 2006, it is in the public convenience and necessity to put high voltage transmission lines directly through residential properties (TRAHVOL Reply, para. 13).

The JIESC argues that the Tsawwassen ROW situation is not unique, believing there are likely many other neighbourhoods in B.C. with similar circumstances, and expresses concern over a potential BCUC decision that could set a costly and unwanted precedent (JIESC Argument, para. 33).

The potential uniqueness of Tsawwassen was tested first by way of information requests and subsequently through cross-examination of BCTC witness panels. The Application refers to Tsawwassen as an area where many homes adjacent to the ROW have been built with their foundations literally on the ROW boundary. While this is the case in a few locations elsewhere on the BCTC transmission ROW, in no case is it so widespread or confining to system operations (Exhibit B1-1, p. 104).

BCTC is not aware of any other existing high-voltage transmission corridor within the transmission system that is directly comparable to Tsawwassen. While the width of the existing ROW in Tsawwassen is ample for a conventional overhead double circuit 230 kV line, the corridor has been totally enclosed by buildings, fences and other barriers. BCTC and BC Hydro have had some difficulties accessing the existing 138 kV lines for vegetation management and other maintenance for years (Exhibit B1-6, BCUC 1.84.1).

There are existing 138 kV, 230 kV and 500 kV overhead lines throughout suburban communities in the Lower Mainland and in a few places elsewhere in the province. This includes North Vancouver, Coquitlam, Pitt Meadows, Burnaby, New Westminster, Surrey and Delta among others (Exhibit B1-6, BCUC 1.84.1; T11:1729; T15:2511). BCTC considers the existing ROW as a permanent and valuable asset, required for the future benefit of all of B.C. Acquisition of a new ROW is certain to become increasingly difficult and costly as economic and population growth continues in the province (Exhibit B1-6, BCUC 1.84.1).

It should be noted that there were no overhead transmission circuits (138 kV or 230 kV) built in the last 20 plus years in the Lower Mainland except short spans to loop supply substations (Exhibit B1-17, BCUC 2.129.1).

Dr. Erdreich acknowledged that in the United States residential properties are adjacent to the ROW and not in the ROW (T28:5304).

The cross-examination process narrowed the potential uniqueness of the Tsawwassen ROW to the issues of EMF, access and use restrictions. BCTC testimony indicates that in terms of EMF Tsawwassen is not unique. What is unique is the way the ROW within the residential properties is entirely enclosed and the way barriers have been allowed to be built (T15:2506-2507). The JIESC submits that the unique access problems BCTC faces have been created by the property owners in violation of the terms and conditions of the ROW agreements (JIESC Argument, para. 35). After reviewing the testimony, the JIESC concludes that the Tsawwassen situation is not unique enough to justify removal of overhead lines at ratepayers' cost. Moreover, the BCUC should not set a precedent that rewards, and thus by implication encourages, non-conforming improvements within the existing ROW (JIESC Argument, para. 39).

#### 6.1.2 Restrictions on the Use of Private Property

TRAHVOL submits Option 2 through South Delta will significantly restrict the use of private property along the ROW. The residents will not be able to build swimming pools, ponds or any structures with foundations, which severely affects the use and enjoyment of their backyards. Similarly, any trees with deep rooting systems are not allowed and the height of trees is restricted due to the remaining overhead line (TRAHVOL Argument, para. 101-104).

BCTC submits that, compared to Option 2, Option 1 would result in greater restrictions on the type of vegetation that could be planted on the ROW and would require BCTC to continue to access properties along the ROW on an ongoing basis to conduct vegetation management and occasional facilities maintenance (BCTC Argument, para. 106)

With regard to permitted uses of properties with Option 2, BCTC notes that while deep, tap-rooted trees would not be permitted to be planted within 5 metres of the centre line of either duct bank, on balance, a greater variety of species could be planted and maintained than with the existing 138kV lines or if Option 1 was in place (BCTC Argument, para. 142).

The JIESC submits that notwithstanding that BCTC argues Option 1 would have the greatest impact during the operation phase of the project, there is no evidence before the Commission to support such a conclusion, in fact, the evidence supports a contrary conclusion because Option 2 retains one of the existing overhead lines (JIESC Argument, para. 52). While supporting Option 1, the JIESC argues that BCTC will also have the added burden with Option 2 to ensure that the public is made aware of the danger of invisible underground lines given the extensive digging and gardening (JIESC Argument, para. 58).

**Commission Determination**

As concluded in Section 5.1, the safety risks inherent in transmission lines can be fully mitigated or reduced to extremely low levels. Simply stated, the submissions of SDSS PAC assume safety risks that are not supported by the evidence in this proceeding. Further, for the reasons stated in Section 5.2, the Commission Panel concludes that it should give little or no weight to concerns arising from EMF. Nevertheless, the Commission Panel would approve a route option other than Option 1, 2 or 3 through South Delta if there was an option that impacted neither residential properties nor First Nation interests and was comparable on cost and reliability criteria. However, the Commission Panel concludes that the task before it is to approve one of Option 1, 2 or 3 because, as discussed in Section 6.2 of this Decision, the financial, non-financial and socioeconomic ratings of Options 1, 2 and 3 set them apart from the other route options.

The Commission Panel finds that Option 1 and Option 2 cannot be distinguished with respect to differences related to use restrictions. BCTC submits that Option 1 will result in greater restrictions on the use of the property than Option 2, and TRAHVOL and the JIESC submit that the converse is true.

In consideration of the evidence presented regarding the uniqueness of the Tsawwassen ROW and restrictions on the use of private property, the Commission Panel concludes that the Tsawwassen circumstances are only unique in terms of access. Even in this regard, the Commission Panel observes that BC Hydro and BCTC have managed the access issues to date and expect to be able to manage them in the future. Further, the existing ROW agreements provide the necessary rights of access to the facilities on the ROW (T15:2508). Moreover, as described in Section 5.3, the long-term effect of Option 1 on property values would likely be modest relative to the existing lines.

In view of all quantitative and qualitative aspects concerning route selection, locating high voltage transmission lines in infrastructure corridors away from residential areas is a preference but not essential. Consistent with this principle, the Commission Panel agrees with BCTC that in the case of a new transmission line on a new ROW, a non-residential route would be, in most circumstances, preferred to a residential route. In the case of an existing ROW, a significant effort should be made to find a cost-effective route away from residential neighborhoods. If no cost-effective solution is found, then it is reasonable for an existing ROW to be used for both new and existing lines.

## 6.2 South Delta Route Options

### 6.2.1 Options 1, 2, and 3

#### 6.2.1.1 Option 1

As described in Section 1.3, Option 1 through South Delta would involve the removal and replacement of all the existing 138 kV wooden H-frame transmission lines with a new 230 kV double-circuit line on single pole steel structures. The new line would be within the existing ROW and a new ROW agreement is unnecessary. Therefore, Option 1 is also the route option with the least risk of delay, and is also the least cost route option (BCTC Argument, para. 105; Exhibit B1-113).

Option 1 was used by BCTC as the base case. BCTC recommended Option 2 because in its view Option 1 would have the greatest impact once it has been built and is providing service. BCTC believes that Option 1 would have the greatest impact from a visual perspective, and submits that the initial opposition to new transmission lines arose from concerns about the visual impact of new overhead transmission lines (BCTC Argument, para. 108-09).

The Commission Panel finds that in the absence of evidence from residents of Tsawwassen, other than from residents along the ROW, the incremental visual impact of the new overhead transmission line on residents off the ROW will detract only modestly from the aesthetics of the community. For the same reason, the Commission Panel finds it should give little or no weight to the evidence of the BCTC witnesses regarding concerns expressed about the visual impacts of new overhead transmission lines. The Commission Panel does accept the evidence of the BCTC witnesses that there was initially broader opposition to new transmission lines and that this opposition included concerns about visual impacts. However, the Commission Panel is unable to conclude from that evidence that the residents of Tsawwassen off the ROW were primarily concerned with the visual impacts of the new steel pole structures. Given the consultation process commented on in Section 3.3, the Commission Panel is not confident that BCTC's capacity to assess stakeholder interests and concerns is sufficiently discerning so as to rely on their evidence in this regard.

Having concluded that the visual impacts to residents of Tsawwassen, other than from residents along the ROW, should be given little or no weight, then it follows that the only Intervenor interests to be considered in a comparison of Option 1 and Option 2 are TRAHVOL and the Customer Class Group.

#### 6.2.1.2 Option 2

Option 2 removes and replaces one of the existing 138 kV lines with a new underground 230 kV cable circuit. BCTC submits that Option 2 is the next lowest cost route option and is estimated to cost $13.8 million more than Option 1 (Exhibit B1-61, BCUC 4.203.1). However, given confidence levels of the estimates, Option 2 and Option 3 (Option 3 without consideration of the costs of the second circuit) are not distinguishable (T18:3195).

BCTC's estimate for Option 2 includes an amount for legal, survey and other costs to effect an exchange of overheard for underground rights. BCTC acknowledges that the costs of acquiring these rights could be much greater than the amount allocated (BCTC Argument, para. 137). The JIESC submits that there is a fundamental flaw in BCTC's reasoning with regard to what it characterizes as an "exchange" of ROW rights with property owners (JIESC Argument, para. 25).

BCTC attempts to limit the potential for significant delay arising from the "exchange" by proposing to seek further direction from the Commission if it appeared that there were unexpected potential delays or costs associated with proceeding with Option 2 (BCTC

Argument, para. 199).

All of the Customer Class Group opposes Option 2. The JIESC submits that the cost of changes to the base case to benefit a special interest group should be borne by the parties requesting and receiving the benefit of the changes (JIESC Argument, para. 32). The JIESC further submits that the impact of Option 1 is certainly not significantly "greater" than the existing status quo to justify this Commission granting a CPCN for Option 2 over Option 1 (JIESC Argument para. 55). CEC submits that BCTC's promise to avoid Option 1 was not well considered internally and does not stand the test of being cost justified versus the benefits (CEC Argument, para. 218). BCOAPO submits that given the strong opposition from the Tsawwassen residents and their refusal to give the Commission any indication of their priorities with respect to Option 1 and Option 2, the Commission should not require BCTC to incur additional capital expenditures for a proposal that was meant to respond to those residents' concerns (BCOAPO Argument, p. 15).

BC Hydro submits that there is a need to make subjective judgments in these types of circumstances and accepts that relatively minor cost increases may be justified where significant public acceptance issues are in play (BC Hydro Argument, para. 20). BC Hydro further submits that BCTC should only be permitted to proceed with Option 2 if the Commission is satisfied that the option can be built in accordance with the schedule identified by BCTC (BC Hydro Argument, para. 22).

#### 6.2.1.3 Option 3

Option 3 is the removal of one of the existing overhead lines in Segment 2 and replacement with an underground circuit in the city streets in Tsawwassen. The estimated incremental cost for Option 3 is $14.8 million, for the first 230 kV circuit, more than Option 1, but as shown in Exhibit B1-113 this is a planning level estimate.

The most significant consideration with respect to Option 3 was stated by counsel for Delta in opening submissions: "So that there is no confusion on that matter, Delta is strongly opposed to Option 3, and does not think it's viable or appropriate" (T6:875-876). The evidence in this proceeding, including the evidence of Delta, reflected this strong opposition by Delta to Option 3.

As stated earlier, the Commission Panel finds that Option 3 is not distinguishable from Option 2 on the basis of the cost estimates provided by BCTC (T19:3491). BCTC also is of the view that if the cost differential between Option 2 and Option 3 is either zero or in fact Option 2 is more costly and will take too long to implement compared to Option 3 BCTC would recommend Option 3 (T18:3200). This conclusion is also reflected in the non-financial analysis presented in Exhibit B1-68 where Options 2 and 3 have a similar non-financial rating. Moreover, TRAHVOL's VITR preferred route through South Delta is Option 3, assuming VITR is approved (T42A:7958).

Unfortunately, BCTC has not been able to collaborate with Delta with respect to development of preferred street options and so has not settled on a specific street route. As stated by BCTC: "When BCTC attempted to explore Option 3 in greater detail during the public consultation process, Delta refused to do so. However, BCTC is not aware of any reason that it would not be feasible to undertake Option 3 and it appears that Delta now acknowledges that Option 3 is, in fact, feasible" (BCTC Argument, para. 153).

In Exhibit B1-1, BCTC made a community contribution proposal for Option 3. A community contribution might be either a cash payment or a contribution in-lieu of cash such as a reduction in installation costs on city streets. Given the approval of Option 1, the merits of a community contribution will not be addressed in this Decision.

The BCOAPO submits that "…while Option 3 is clearly preferable to Option 4, 5 and 6, it is not preferable to Options 1 or 2" (BCOAPO Argument, p. 9). The JIESC submits that "…because of the level of uncertainty with respect to the route being advanced, the lack of any serious notice to affected parties, the planning level cost estimates, and the lack of evidence concerning schedule and timing of Option 3, that this Commission cannot conclude that Option 3 is in the public interest" (JIESC Argument, para. 74).

**Commission Determination**

The Commission Panel expects that if EMF and safety concerns had been supported by the evidence then those concerns would have been determinative. They were not. Therefore, regarding the selection of the preferred route through South Delta amongst Options 1, 2 and 3, the Commission Panel concludes that it should give considerable weight to two considerations: 1) the existing ROW, particularly in these circumstances where most residents bought their properties with knowledge of the existing ROW, and 2) the limited incremental impacts associated with the upgrade. Regarding the selection from Option 1 or 2, the Commission Panel concludes that it should give considerable weight to the lack of an expressed preference by TRAHVOL between Options 1 and 2. Regarding the selection from Option 1 or 3, the Commission Panel accepts that Option 3 has considerable merit and that city streets are often a better location for transmission lines than are residential properties. However, in this instance, where the city streets are through residential neighborhoods, the advantage of placing the transmission lines under city streets is diminished. If both Delta and TRAHVOL had preferred Option 3 to Option 1 or 2, further consideration of Option 3 would have been necessary, and additional evidence regarding Option 3 may have been available and valuable.

The Commission Panel concludes the cost-effectiveness of “undergrounding” for Option 2 cannot be supported in the absence of an express preference by the intended beneficiaries of undergrounding. If those intended to benefit do not accept that there are benefits, then Option 2 is simply not cost-effective as compared to Option 1. TRAHVOL’s concerns go far beyond the issue of overhead or underground lines; therefore, TRAHVOL chose not to express a preference between Option 1 or 2. However, when BCTC did not get support for Option 2 from the intended beneficiaries it should not have pursued Option 2, and it did not matter why a preference was not expressed. Instead, BCTC should have recommended Option 1. When the potential for delay and significantly increased costs associated with acquisition of new ROW rights for Option 2 is also considered, BCTC’s recommendation is even less understandable. . The best explanation for BCTC’s actions and recommendation may be that once committed to Option 2, BCTC was no longer willing or able to be influenced by the opinions of its customer groups nor the evidence in this proceeding (T15:2483-2494). Moreover, BCTC should have canvassed ratepayers, other than TRAHVOL, regarding its recommendation for Option 2 prior to its commitment not to recommend Option 1.

The JIESC submits that BCTC did not, and has not, properly canvassed or assessed the ratepayer interests in reaching its conclusion to put Option 2 as its preferred route option through South Delta (JIESC Argument, para. 45). There may be circumstances where it becomes appropriate for a utility to make a commitment to one stakeholder that is contrary to the interests of other stakeholders, but none can be envisaged by the Commission Panel in this context, at least on the evidence in this proceeding

The Commission Panel concludes that it must decide the preferred route option based on a consideration of the public interest, and the BCTC commitment should be given no weight in that determination. The Commission Panel generally accepts the submissions of the Customer Class Group that the additional cost of Option 2 as compared to the cost of Option 1 is not justified, particularly where the impact of Option 1 is not significantly "greater" than the existing circuits. Further, the Commission Panel affords considerable weight to the potential for significant delay and costs to acquire ROW rights for Option 2, and finds that the risk of delay for Option 2 is greater than for either Option 1 or Option 3. One of the benefits of Option 3 is the same benefit of Option 2, that is, the new line would be underground and removed from public view. In the case of Option 2 it would be underground on the ROW, and in the case of Option 3 it would be underground in city streets. However, under Option 3 a greater number of people could be exposed to EMF and, as previously stated, they would be a new group of residents, who would have purchased properties prior to the new ROW being established.

BCTC proposed Option 1 if it did not get an agreement to a ROW from 51 percent of the residents in Segment 2 (BCTC Argument, para. 3). It would appear that BCTC now acknowledges that its recommendation for Option 2 cannot be justified in the absence of an agreement from those intended to benefit from building the lines underground. As stated above, TRAHVOL's concerns go far beyond the issue of overhead or underground lines. Therefore, there is no reason to believe that BCTC's proposal is more than an unfortunate attempt to obtain some support for a recommendation that very clearly has none. BCTC should simply have abandoned its expectation that residents along the ROW when facing either Option 1 or 2 would express a preference for Option 2 in the form of a ROW agreement for Option 2. The only reason to believe that a preference would be expressed in this manner is if BCTC's characterization of this as an exchange had been accepted by TRAHVOL. It was not. Therefore, the Commission Panel concludes that BCTC's 51 Percent Proposal is completely without merit.

Contrary to the submissions of BC Hydro, the Commission Panel concludes that Option 3 should be considered with Options 1 and 2 because Option 3 cannot be distinguished from Option 2 on cost considerations and Options 1, 2, and 3 have a similar non-financial rating (Exhibit B1-68), although the Commission Panel notes that impacts may be distributed across different residents in Option 3. The Commission Panel notes that Option 3 may be considerably more costly than either Option 1 or 2 if the cost of the next transmission reinforcement to Vancouver Island is considered. However, the Commission Panel finds that, for the purposes of this Decision, such additional costs need not be considered. Therefore, the selection between Options 2 and 3 does not turn on a conclusion that Option 2 is less costly than Option 3, as is suggested by BC Hydro. Nevertheless, the Commission Panel concludes that Option 1 is preferred to Option 2 because Option 1 is more cost-effective than Option 2, and for similar reasons Option 1 is preferred to Option 3 because Option 1 is more cost-effective than Option 3. Because Option 1 is the selected route, considering Options 2 and 3 together does not change the decision. However, so that these reasons may be understood, the Commission Panel expressly rejects the submissions of BC Hydro that the only debate is between Options 1 and 2.

The Commission Panel notes the submission of TRAHVOL during the Oral Phase of Argument that if the Commission Panel concludes that a permutation of VITR has to be approved then TRAHVOL's preference is for Option 3 (T42A:7958). The Commission Panel accepts that Options 1, 2 and 3 should be considered to have a similar non-financial rating, although the risk of delay for Option 3 would have been considered to be less than Option 2 if it had the support of Delta (Exhibit B1-68).

### 6.2.2 Construction Impacts for Options 1, 2, and 3

There are two construction-related activities associated with VITR: 1) the removal of the existing line(s), and 2) the installation of the new line. In all cases, removal is not expected to cause significant disruption but installation of Option 1, 2, or 3 will impact the Tsawwassen community, albeit in different ways.

A comparison of construction impacts for VITR Options 1 and 2 was provided by BCTC (Exhibit B1-11, BCUC 2.127.1). Of particular note is the difference in the area impacted during construction- approximately 450 $m^2$ for Option 1 compared to approximately 53,800 $m^2$ for Option 2.

During the hearing, a witness for BCTC described Options 1 and 2 construction impacts in some detail. The impacts were viewed as being similar for Options 1 and 2 if traffic issues at road crossings, noise, and transport and staging of large equipment were also considered (T15:2481).

For property owners along the ROW, the impact of Option 1 would range from minimal to significant depending on whether or not a new pole is erected on the property and whether access to adjoining properties is required, but BCTC does not expect to use large equipment in the backyards (T15:2476, 2478-79). On properties where a new pole is installed, a concrete foundation would likely be poured (T15:2477) using a pumper truck (T15:2480). The towers would be installed in sections and then the wires would be pulled (T15:2477-79).

Construction of VITR Option 2 would have a significant impact on the property owners along the ROW with a construction corridor up to 20 metres wide through the backyards along the ROW (T9:1274). This area would be cleared of vegetation, fenced and covered with material that could withstand construction vehicles. Then construction vehicles such as excavators and dump trucks would be brought in to excavate a trench, install the ducts and spacers, cover the ducts with concrete and backfill the area to restore the property to its former level (T9:1276-79). BCTC considers Option 3 to have the greatest construction impacts because of the traffic disruption and the numbers of people impacted (T9:1233).

### 6.2.3 Options 4, 5, 6 and 7

#### 6.2.3.1 Option 4

Option 4 involves removing one of the existing 138 kV lines from the ROW and replacing it with a 230 kV line along Highway 17. BCTC's planning level estimate of the incremental costs of Option 4 is $17.6 million for the first 230 kV circuit, although BCTC submits that cost was not the determinative factor in BCTC's decision not to pursue Option 4 (Exhibit B1-61, BCUC 4.203.1; BCTC Argument, para. 159). Participants, including Mr. Holmsen and Delta, proposed variations to this basic route option. Option 4 and variations of Option 4 were pursued vigorously during the hearing process by most Intervenors except the Customer Class Group and BC Hydro.

The starting point for consideration of Option 4 is the impact on First Nations lands. As stated by TFN:

> "Tsawwassen First Nation does not support Option 4. An "above ground" application raises concerns around EMF and the visual impact of the works for our present and future residents and businesses located in proximity to Highway #17. An "underground" application raises tremendous concerns around the impact to the archaeological remains of our community, which are of great antiquity and scientific and cultural importance. Tsawwassen First Nation would bear the brunt of the physical impacts of this component of the project, and receive no benefit from it whatsoever" (Exhibit C6-8, Exhibit K).

TFN also appeared at the Town Hall Meeting and stated:

> "Among the alternatives presented to the proposed alignment, is the so-called "Option 4". This proposal would see the alignment diverted along Highway 17, and through lands that are included in a potential treaty Settlement with Tsawwassen First Nation, and through the Tsawwassen First Nation community itself" (Exhibit E-59; T5:655).

One of the relevant issues for determination by the Commission Panel is whether or not Option 4 requires a new ROW or permit from TFN. BCTC submits that Option 4 does require a new permit from TFN (BCTC Argument, para. 159), and submits that there is a real possibility that TFN would refuse to issue a permit for Option 4 (BCTC Reply, para. 139). Mr. Holmsen and Delta are of the view that a new permit from TFN is not required either because the existing ROW provides the necessary rights or because the ROW can be located off of TFN lands. Moreover, if one is required then the Commission should not give weight to this submission of BCTC because BCTC made no effort to negotiate with TFN (T25:4777, T12:2058, T25:4761).

The first issue for consideration is whether or not a new permit for TFN is required. Parties to the Agreement in Principle express different positions regarding ownership of Highway 17. As stated in the Agreement in Principle:

> "The Parties acknowledge they hold different legal positions in respect of the ownership of that part of the Crown Corridor known as Highway #17 where it bisects Tsawwassen Reserve. Nothing in this Agreement in Principle affects the ownership of Highway #17, including the ownership of land underlying Highway #17" (Exhibit B1-89).

BCTC is of the view that even if the Province owns Highway 17 it does not matter because Highway 17 should not be used as an option because the whole embankment of Highway 17 is subject to movement in a seismic event (T16:2659). Mr. Holmsen submits that the subsurface along Highway 17 may be more stable than expressed by BCTC, and warrants closer examination before being rejected as an excessive risk (Holmsen Argument, p. 6).

Mr. Holmsen submits that TFN have not reached a point where TFN have indicated that "…under no circumstances would they permit Option 4" (T25:4775). Mr. Holmsen submits that there has been no constructive exchange of ideas between BC Hydro/BCTC and TFN for means of accommodation and compensation (Holmsen Argument, p. 10). Mr. Holmsen further submits that suggestions regarding interaction amongst TFN, BC Hydro, BCTC, Delta and representatives from the community were never acted upon. However, BCTC submits that Highway 17 is provincially owned and controlled, and any construction and installation of transmission cables within that ROW would be the subject of payments to TFN for compensation, accommodation, or ROW acquisition. Mr. Holmsen submits that BCTC has not appropriately, and in detail, presented the Highway 17 proposals to TFN (Holmsen Argument, p. 8). BC Hydro submits that BCTC has selected and advocated for a preferred route option, which, among other advantages, accommodates First Nation interests. Moreover, given the uncertainty of the route options, BC Hydro submits that it is not a reasonable expectation for BC Hydro to have negotiated final and binding ROW agreements with TFN (BC Hydro Argument, para. 47).

TRAHVOL submits that Option 4 has not been explored by BCTC in sufficient detail for the Commission to determine whether or not it might be in the public interest (TRAVHOL Argument, para. 128).

In BCTC's opinion there is a real possibility that it would not be able to acquire the necessary permits to construct Option 4 due to archaeological and environmental concerns (BCTC Reply, para. 142). BCTC advises that the Archaeological Branch supports the recommendation that Option 4 not be selected over the preferred Option 2 (BCTC Argument, para. 163). Regarding environmental concerns, Option 4 will require significantly more cable burial in the inter-tidal zone south of the ferry causeway, outside of the existing corridor than Option 1, and also impact more shoreline, wetlands and brackish water habitat away from the shore. BCTC submits that Option 4 may be rejected in the Environmental Assessment process (BCTC Argument, para. 167).

BCTC's witness testified that the archeological impacts of Option 4 are greater than Option 2. Mr. Holmsen and Delta are of the view that horizontal directional drilling could be used to avoid contact with the archeological site (Delta Argument, para. 195-196).

BCTC also submits the seismic risk of Option 4 is greater than the seismic risk of Option 2, although BCTC does not submit that Option 4 is infeasible from a seismic risk perspective, and it follows that the seismic risk of Option 1 is similar to Option 2.

Delta submits that:

> "It is interesting that, despite BCTC's various protestations about the poor soil conditions along Highway 17, its lack of knowledge of actual conditions, and the need to conduct costly and time-consuming work, BCTC had in its possession information that does not support its conclusions about the geological conditions along Highway 17, and which should have justified further investigations by it" (Delta Argument, para. 205).

Delta notes that the National Harbours Board test holes from the BC Ferries causeway show that the soil at the area where the causeway meets the shoreline is not significantly susceptible to liquefaction, and submits that the evidence supports the feasibility of the modification to Option 4 proposed by Mr. Laprade (Exhibit B1-57, Attachment 3).

Further, Delta submits that no weight can be given to the evidence of Mr. Williams on the seismic risk along Highway 17, and that a combination of the Option 4 and Options 1, 2 and 3 would be equal in terms of their geological hazards (Delta Argument, para. 203). BCTC submits that Delta's Modified Option 4 does not address any of the other deficiencies documented in the record (BCTC Reply, para. 156).

#### 6.2.3.2 Option 5

Delta and Mr. Holmsen also propose an Option 5. Option 5 would remove one of the existing 138 kV lines from the ROW but would bypass Tsawwassen and the existing TFN reserve by paralleling the existing HVDC Pole 2 corridor north of Deltaport Way. The planning cost estimate for Option 5 is $27 million more than Option 1 (Exhibit B1-113). In BCTC's opinion, any route north of Deltaport Way is infeasible (T9:1202).

BCTC believes that the seismic risk is unacceptable (BCTC Argument, para. 174), and the risk of damage from anchors is unnecessarily high (T9:1202). Further, BCTC believes that Option 5 has an impact on native lands in Tsawwassen because a portion of Option 5 crosses land under negotiation for proposed TFN settlement lands (Exhibit C6-8, Exhibit K). In addition, BCTC believes that Option 5 would have additional impacts on wetlands and shore areas along

Deltaport Way and north along the dike toward Canoe Pass (BCTC Argument, para. 176). BCTC concludes that Option 5 is infeasible.

6.2.3.3 Option 6

Option 6 involves removing one 138 kV lines through Tsawwassen and replacing it with a submarine cable through Boundary Bay around Point Roberts to TBY. The incremental estimated cost of Option 6 is $69 million (Exhibit B1-113). Option 6 would require a new ROW for approximately two kilometres in South Delta between the existing corridor and the shore of Boundary Bay.

Like Option 5 but for different reasons, BCTC concludes that Option 6 was infeasible because of the additional ROW through U.S. waters and significant environmental impacts (BCTC Argument, para. 185).

6.2.3.4 Option 7

Option 7 is either Option 2 or Option 3 with installation of the second circuit of 230 kV underground cables. The benefit is the removal of both existing overhead lines in Segment 2. BCTC believes that the incremental costs of Option 7 are not justified in the absence of a community contribution (BCTC Argument, para. 186).

**Commission Determination**

The Commission Panel accepts that Option 4 should be considered to have a non-financial rating that is significantly less than Options 1, 2 and 3 (Exhibit B1-68).

The Commission Panel accepts that TFN expressly and consistently made their concerns about Options 4 and 5 known to BCTC and BC Hydro (T18:3201, BCTC Reply, para. 139). Further, the Commission Panel accepts that there is a high permitting risk with Option 4, either due to archeological or environmental concerns, and a high impact on First Nations. Although the

Commission Panel does not accept the rating of the risk of delay of Option 3 relative to Option 2 as shown on Exhibit B1-68, it does accept there is a significantly greater risk of delay with Option 4 than with Option 1.

The Commission Panel concludes that a new agreement with TFN would be required for Option 4 based on the evidence in this proceeding taken in the context of comments from counsel for Delta. In this regard, the Commission Panel prefers the evidence of the witnesses for BCTC (T17:3016) to the evidence of the witness for Delta (T22:4172). The Commission Panel accepts the submissions of Mr. Holmsen that BCTC or BC Hydro should have had discussions with TFN regarding compensation, perhaps in the form of a monetary payment. The Commission Panel accepts the submissions of BC Hydro that it was not a reasonable expectation to negotiate final agreements; however, it was a reasonable expectation that such compensation was the subject of negotiations. In these circumstances, more evidence with respect to the views of TFN regarding compensation may have been helpful to the Commission Panel.

The Commission Panel finds that after BCTC made its commitment not to recommend Option 1, it was reasonable to expect that BCTC or BC Hydro would discuss compensation with TFN for Option 4. The Commission Panel finds that an “exchange” for Pole 1 from a reliability perspective is not appropriate; however, BCTC should have pursued another means of obtaining TFN support.

The Commission Panel does not accept the evidence of Golder & Associates with respect to the seismic risk of the terrestrial portions of Option 4, and in this regard prefers the evidence of Mr. Laprade. Therefore, seismic risks attested to by BCTC regarding Option 4 are given little or no weight by the Commission Panel in comparing Option 4 with Options 1, 2 and 3. However, the incremental costs and First Nations impacts are of considerable concern to the Commission Panel and are determinative of the preference for Option 1 over Option 4.

The Commission Panel accepts the submissions of BCTC that Options 5 and 6 are infeasible. For the reasons that the Commission Panel prefers Option 1 to Options 2 and 3, the Commission Panel also prefers Option 1 to Option 7.

### 6.3 Southern Gulf Islands Route Options

BCTC proposes to replace the two existing 138 kV overhead circuits on Galiano Island and Salt Spring Island with a new 230 kV double overhead circuit, which would be comparable to Option 1 through South Delta. The other options considered by BCTC included underground construction in selected areas on Galiano Island and Salt Spring Island and bypassing the Gulf Islands using either HVDC Light® or conventional HVDC. The incremental costs of the underground options would be a minimum of $40 million, and the incremental costs of the bypass options would be a minimum of $170 million (Exhibit B1-1, p. 107, Exhibit B1-6, BCUC 1.96.2, BCTC Argument, para. 206).

In the event that JdF or VIC is approved, IRAHVOL submits that the superior solution for continuing to supply the Gulf Islands with electricity is to retain the existing 138 kV circuits from VIT to Salt Spring Substation and to serve Galiano, Mayne, Pender, and Saturna Islands from Salt Spring Substation at 25 kV, using the existing circuit loop reinforced if necessary with spare cable available in Trincomali Channel (IRAHVOL Argument p. 52). In this Decision, VITR is approved so no further comment regarding this submission of IRAHVOL is necessary.

In the event that the Commission approves VITR, IRAHVOL requests that the Gulf Islands circuits be built underground, and that a compensation program be approved for those property owners that no longer wish to live in the vicinity of the ROW (IRAHVOL Argument, p. vii). In support of undergrounding, IRAHVOL refers to Exhibit C10-8 and a December 2004 Ipsos Reid survey that states that:

> "…the Gulf Islands are a special part of British Columbia and that 87% agreed that the BC Government should take action to make sure the Gulf Islands are preserved and protected for all British Columbians" (IRAHVOL Argument, p. 71).

IRAHVOL also refers to Exhibit C35-4, which shows more than a "…hundred vessels anchored or moored in Montague Harbour." IRAHVOL states:

> "For the last fifty years, visitors to Montague Harbour from all over the world have been affronted by the existing overhead power lines. If residents and a small number of visitors to Tsawwassen are worth $14 million, surely the residents and the hundreds of thousands of annual visitors to the Gulf Islands are worth $70 million.…Undergrounding through the Gulf Islands should be justified by the benefits created by the additional costs. In IRAHVOL's view, as discussed in IRAHVOL's policy evidence, Exhibit C34-6, the benefits created by the removal of the visual impacts of overhead transmission justify the additional costs of undergrounding…"(IRAHVOL Argument, p.72).

The Salt Spring Island Official Community Plan includes a provision directed to BCTC regarding transmission lines and states:

> "The utility is also asked not to develop new high voltage transmission lines in areas that are designated for medium or high density residential use, health care, child care, schools, or public assembly building" (Exhibit C10-5, p. 3).

BCTC submits that the VITR facilities are an improvement over the existing facilities and consistent with the Official Community Plan (BCTC Reply, para. 165).

Maracaibo refers to four issues identified in its opening statement and a submission made prior to the hearing. Maracaibo supports further consideration by BCTC and BC Hydro of the HVDC Light® technology. BCTC submits that only two properties at Maracaibo Estates are located on the ac ROW.

As stated in Section 5, long-term incremental property value impacts of VITR are expected to be insignificant.

**Commission Determination**

The Commission Panel finds that the significant additional cost of undergrounding the VITR facilities through the Gulf Islands is not justified, particularly in circumstances where the new overhead facilities will be an aesthetic improvement over the existing facilities. The Decision addresses the VIC and JdF alternatives in Section 7.

### 6.4 Overhead Options and Stage 2 Preparatory Work

BCTC proposes to make prudent preparations for future construction of a second 230 kV circuit, for which there is currently a forecast need in 2017 (Exhibit B1-1, p. 25). BCTC would apply for a CPCN for the second circuit (VITR Stage 2) when necessary.

In preparation for Stage 2, BCTC proposes to take two actions now (Application, pp. 28-39). The first, which applies to the overhead segments of any VITR route, is to immediately remove the overhead portions of both existing 138 kV single-circuit lines and install one new double-circuit line on steel poles. Both of the new overhead circuits would be constructed to 230 kV standards, though one circuit would be operated at 138 kV to supply substations on Salt Spring and Galiano Islands until Stage 2 of the project is completed. The second action, which applies only to the proposed underground portion Option 1 through South Delta, is to install a second set of conduits in certain locations along the ROW to minimize Stage 2 construction impacts. The second set of conduits would allow the future installation of additional underground cables without having to dig up the affected properties again.

BCTC provided cost estimates for several different designs for the overhead segments of VITR (Exhibit B1-17, BCUC 2.163.1), as shown in the following table.

**Table 6-1: Cost Estimates for Overhead Segments of VITR**

| **Description** | **NPV [k$]** |
|---|---|
| Double-circuit steel pole, line constructed in 2008 (VITR proposal) | 34,179 |
| Single-circuit wood H-frame, Stages 1 and 2 | 30,120 |
| Single-circuit steel pole, Staged conductor installation | 40,136 |
| Double-circuit steel pole, Staged conductor installation | 33,458 |

The analysis indicates that, as BCTC expected, the single circuit wood H-frame option has the lowest NPV for all cases studied, though the cost differential is relatively small. BCTC notes that the analysis does not include staged wood H-frame impacts such as higher maintenance costs, requirements for a wider corridor, higher EMF values, different visual impacts (more poles), increased construction impacts on residents, and additional definition-phase costs due to public consultation and additional environmental assessment requirements.

**Commission Determination**

Given that the Commission Panel has ruled that Option 1 is the preferred route through South Delta, there is no requirement for BCTC to undertake the Stage 2 preparatory work related to Option 2. With respect to Option 1, the Commission Panel accepts BCTC's view that the cost differential between staged wood H-frame construction and the recommended double-circuit steel pole construction in 2008 is relatively small. **The Commission Panel also finds that the disadvantages of the wood H-frame option outweigh the cost advantage, and therefore directs BCTC to implement Option 1 as described in the Application.**

### 6.5 ROW Agreements

Consideration of the Segment 2 route options necessarily needs to include consideration of the ROW agreements encumbering the properties in Segment 2. This Section of the Decision addresses the issue of whether or not the ROW agreements provide BCTC with the right to build Option 1. If the ROW agreements provide BCTC with the right to build Option 1, then Option 1 has advantages over the other options that are relevant to the Commission Panel's selection of the preferred Option. The Commission Panel notes that this issue is a contractual matter for the courts. However, the advantages provided by the ROW agreements regarding Option 1 are relevant to this Decision.

The typical ROW agreement has the following provision:

> "… hereby grants in perpetuity … the right and easement …to construct, erect, operate and maintain towers and poles...and to string one or more lines of wire for the transmission and distribution of electrical energy and for communication purposes…" (Exhibit B1-6, BCUC 1.3.2).

Mr. Holmsen submits that there is no provision specified in the typical ROW agreement to upgrade or install a new or higher voltage transmission line (Holmsen Argument, pp. 35-36).

BCTC suggests the issue has been fully addressed by the British Columbia Court of Appeal in *Hillside Farms Ltd. v. British Columbia Hydro and Power Authority,* [1977] 3 W.W.R. 749; [1977] B.C.J. No. 1010 (QL) *[Hillside]* (BCTC Reply, para. 102). In *Hillside* the Court of Appeal dismissed an appeal on the issue of the liability of BC Hydro for breach of contract by way of excessive use of a power line ROW through the appellant's property. The appellant specifically complained about the higher voltage of two subsequent power lines, their location and their design (*Hillside,* para. 5).

The terms of the grant of ROW before the Court of Appeal in *Hillside* were cited at paragraph 3 in that case report as follows:

> "…in perpetuity…from time to time to construct, erect, string, operate and maintain eight towers only with internal guy wires, brackets, crossarms, insulators, transformers, anchors and their several attachments, and one or more lines of wire for the transmission and distribution of electrical energy upon all that portion (hereinafter called 'the right of way') of the land…".

TRAHVOL and Mr. Campbell commented on the applicability of the *Hillside* decision during the Oral Phase of Argument. TRAHVOL distinguishes the Hillside decision on three points: 1) the language considered in Hillside is different than the ROW agreements, 2) Option 1 is a new line replacing an existing line, and 3) the issue of EMF (T41:7585-7586). Mr. Campbell distinguishes the Hillside decision on the basis of consideration outside the four corners of the agreement (T41:7588).

**Commission Determination**

The Commission Panel concludes the ROW agreements can reasonably be assumed to provide BCTC with the right to build Option 1, and accepts the reply submissions of counsel for BCTC that the rights were granted in perpetuity and were not limited to existing facilities (T41:7589-7590).

### 6.6 Property Restoration

Property restoration is primarily an Option 2 issue because of the large area of private land that will be cleared and excavated but many of the issues discussed in this Section also apply to Option 1 to some extent. TRAHVOL asked Sheryl Lee Clark to inspect a sample of yards along the ROW, in order to provide an estimate of the cost to restore the landscape of these properties. BCTC asked Envirow Consulting Inc. to prepare a report derived from orthographic photos and other project documents (Exhibit B1-63). The reports indicate that at least a 50 percent difference in the restoration costs for Option 2, which has been estimated by BCTC to be $1.3 million (T18:3185). As stated earlier, this difference in restoration costs is most relevant to a comparison of the costs of Options 2 and 3.

Intervenors who own some of the affected properties expressed concern about the impact on the yards, particularly on mature trees and shrubs. BCTC acknowledged that, in the case of mature vegetation, it may take a significant amount of time for yards to reach their pre-construction state (Exhibit B1-11, Holmsen 1.38.4; T17:2910-11).

Property owners were also concerned about which improvements would be restored and replaced. BCTC has stated that it will endeavour to restore and replace all conforming improvements (Exhibit B1-11, TRAHVOL 1.32.2 and Holmsen 1.38.1) but that it cannot guarantee that every non-conforming encroachment would be accepted or compensated for if it has to be removed (BCTC Argument para. 139).

BCTC has not yet identified the conforming and non-conforming improvements or structures on the ROW. A non-conforming structure is a structure that may interfere with the safe and efficient operation of transmission works, and is contrary to the ROW agreement in place. However, general guidance on what constitutes a conforming or non-conforming use is provided in the *Right of Way Guidelines for Compatible Use* (Exhibit B1-6, BCUC 1.14.1). BCTC states:

> "If BCTC removes a non-conforming structure or improvement then, once construction of the new line is completed, BCTC will landscape the area from where the non-conforming structure or improvement was removed to the condition the surrounding land was in prior to installation of the new line. In many cases, it may be possible to reach agreement with the landowners on how to make non-conforming structures conforming …" (Exhibit B1-6, BCUC 1.14.2).

All lands and conforming improvements will be restored to pre-construction condition (Exhibit B1-1, p. 52; Exhibit B1-17, TRAHVOL 1.99.1). However, BCTC recognizes that it can take time for disturbed landscaping to become reestablished. BCTC will work with individual landowners to develop a suitable plan and timetable for restoration of landscaping that is compatible with the ROW and that maintains key landscape values. BCTC will pay compensation and/or restoration costs based on that plan (Exhibit B1-11, Holmsen 1.38.4).

In response to an information request, BCTC "…confirms it intends to restore to previous condition only conforming improvements" (B1-11, BCUC 2.138.3). However, in testimony BCTC states that its intent is to try to find ways to restore non-conforming improvements provided that such features are consistent with the operation and maintenance of the line (T19:3485). This raises a question as to whether or not only conforming improvements can be consistent with the operation and maintenance of the line, but this question does not need to be addressed in this Decision.

The next issue for consideration is whether or not the Commission has the jurisdiction to order a public utility to compensate property owners for adverse impacts of utility plant or system in respect of both conforming and non-conforming improvements. There was a division of opinion amongst the parties who responded to this question. At the time of filing Appendix A, an Errata Sheet, and a blacklined copy of BCTC's Argument, BCTC's counsel advised the Commission that he had inadvertently failed to address this question. In BCTC's view there is nothing in the *UCA* that allows the Commission to directly alter the terms of a contract between a utility and a third party, but the Commission does have broad powers under Section 45(3) to determine the conditions or terms upon which a CPCN can be issued. BCTC believes that the Commission does have jurisdiction, in circumstances it considers appropriate, to order BCTC to compensate property owners for adverse impacts of utility plant or system to both conforming and non-conforming improvements as a term or condition of granting a CPCN for VITR. It further submits, however, that the Commission does not have any general power to determine what constitutes a conforming or non-conforming improvement or to order that a non-conforming improvement could be left in place, contrary to the contractual terms of the ROW agreement (Fasken Martineau letter, April 12, 2006).

BC Hydro submits that the *UCA* does not provide the Commission with the jurisdiction to order a public utility to compensate property owners for adverse impacts of the transmission system in respect of conforming improvements. According to BC Hydro, such matters are matters for the courts. BC Hydro acknowledges, however, that it is appropriate for the Commission to take such costs into consideration in evaluating a project's costs (BC Hydro Argument, para. 17).

The JIESC also submits that this issue was beyond the Commission's jurisdiction. It argues:

> "What is a conforming or non-conforming improvement is contained in the ROW Agreements themselves and accordingly, any contractual dispute concerning the interpretation of 'improvements' is a matter of contractual interpretation and accordingly a civil dispute between BC Hydro and third parties**"** (JIESC Argument, para. 66).

The JIESC further submits that if BCTC proceeds with Option 2, then compensation will be determined by negotiation or the law governing expropriation, in which latter event the *Expropriation Act* takes precedence over the *UCA***.** The JIESC submits that the Commission's involvement in matters relating to contractual disputes, negotiation and expropriation is limited to a review of whether the expenditures had been prudently incurred. Alternatively, the JIESC argues that if the Commission determined it did have jurisdiction to determine whether, and in what amount, compensation is payable to landowners, it should not exercise its discretion for three reasons:

> (a) "First, the Commission's decision to award compensation to a property owner renders the Commission incapable of reviewing its own decision at a later date when it considers whether BCTC's expenditures were prudent and the associated impact on rate base;

(b) Secondly, and strictly from a policy perspective, this Commission should not set a precedent that rewards, and thus by implication encourages, non-conforming improvements within an existing ROW which 'improvements' are arguably infringements that offend the provisions of ROW agreements; and

(c) Thirdly, the Commission risks awarding compensation to a property owner in an amount which is inconsistent with what the Inquiry Officer or Court under the *Expropriation Act* would have awarded in past decisions" (JIESC Argument, para. 69).

Sea Breeze submits the Commission does have jurisdiction to order a public utility to compensate property owners for adverse impacts of utility plants and systems. The submission was based on the support of Sea Breeze for a broad and liberal approach in interpreting the Commission's jurisdiction under the ***UCA.*** It also argues that the jurisdiction could be found, *inter alia,* in the Commission's jurisdiction to attach conditions to a CPCN under Section 45(3) or in its general jurisdiction to make orders for the "safety, convenience or service of the public" under Section 23(1)(g)(i) of the *UCA* (Sea Breeze Argument, para. 402).

IRAHVOL also argues that the Commission has jurisdiction to award compensation. It submits that compensation could be justified as a cost of doing business, that there was nothing in the general law that prevented compensation and that Sections 59-60 of the *UCA,* which deal with rates, authorize the Commission to make such an order "…provided the basis on which compensation is offered is consistently and fairly applied" (IRAHVOL Argument, pp. 80-81).

TRAHVOL agrees with the BCTC position that Section 45(3) of the *UCA* is sufficiently broad to provide jurisdiction to the Commission to order, as a condition of a CPCN, compensation to property owners for impacts on conforming and non-conforming uses (TRAVHOL Argument, para. 25).

Delta submits that the Commission has the jurisdiction to order compensation to property owners for adverse impacts on conforming and non-conforming uses on what appear to be contractual and/or reliance grounds (Delta Argument, para. 47).

**Commission Determination**

The Commission Panel accepts the submissions of BCTC that it does have jurisdiction to order compensation to property owners for conforming and non-conforming improvements as a condition of a CPCN. Further, the Commission Panel accepts BCTC's submission that distinguishing conforming from non-conforming improvements is a matter for the courts. However, the Commission Panel concludes that it may need to distinguish between conforming and non-conforming improvements for rate-making purposes. The Commission's jurisdiction to interpret contracts for rate-making purposes was considered in *BC Gas Utility Ltd. v. British Columbia Hydro and Power Authority and British Columbia Utilities Commission* (31 May 1995), Vancouver CA17981 (BCCA)where the Court said:

> **"**It was in my view proper for the Commission to determine for rate-making purposes how the agreement should properly be applied - - that is to say what it meant in terms of the price to be paid per unit of gas purchased. I cannot accept the contention of the authority that the Commission had no jurisdiction to interpret contracts in the course of performing its regulatory function. To the contrary, it would be impossible for the Commission to perform its function if it could not do so. There is, of course, opportunity for an aggrieved party to have recourse to the courts in the event the Commission should err in law in its interpretation of a contract, but, as I have said, I do not understand the authority to assert any such error in this case. The decision of this court in *Crestbrook Pulp and Paper Co. v. Columbia Natural Gas Ltd.* (1978), 87 D.L.R. (3d) 248, on which the authority relies, deals with the right of a customer to sue a utility for damages for breach of a gas supply contract by overcharging. That decision says nothing that I can find which would limit the jurisdiction of the Commission to interpret and give proper effect to relevant contractual provisions affecting a utility in the course of carrying out its ordinary regulatory functions" (para. 8).

Therefore, the Commission Panel concludes that it may interpret the ROW agreements so as to distinguish between conforming and non-conforming improvements, and then exercise its jurisdiction to make an order regarding restoration costs for conforming or non-conforming improvements. Given the uncertainty regarding restoration costs and the limited investigation by BCTC regarding distinctions between conforming and non-conform improvements, the Commission Panel concludes that it should not exercise its jurisdiction to order compensation to property owners and expressly declines to exercise that jurisdiction at this time. **Instead, the**

**Commission Panel directs BCTC to establish an account for what it considers conforming restoration costs and another account for what it considers non-conforming restoration costs.** The Commission Panel concludes that conforming restoration costs can appropriately be included as project costs. BCTC may seek approval for recovery of non-conforming restoration costs, but it should ensure that such restoration costs are documented in restoration plans so that adequate justification for such recovery can be made available to the Commission. The justification of such recovery should consider the magnitude of the costs, the history of the improvement, and other construction impacts on the affected property.

## 7.0 COMPARISON OF VITR, VIC AND JDF

A significant portion of the written and oral evidence in the proceeding focused on comparing VITR, VIC and JdF. Sea Breeze's CPCN Application for VIC was withdrawn during the proceeding, but Sea Breeze continued to argue that a VIC-like project reflecting an alternative technology and route to VITR should still be considered in determining whether VITR is in the public interest. Sea Breeze also argued throughout the proceeding that JdF was a viable alternative to VITR and should also be considered in determining whether VITR is in the public interest.

In order to determine whether VITR is in the public interest, this Section of the Decision compares VITR to VIC and JdF. The comparison is made on the basis of schedule risks, reliability impacts, direct and indirect costs, and overall rate impacts for each alternative. Financing issues associated with JdF are discussed in Section 8 of the Decision. Based on the determinations in Section 6 of the Decision, VITR, with Option 1 through South Delta , is used for the purposes of the project comparisons in this Section. VITR Options 2 and 3 through South Delta are also included in the discussion of schedule risks. VIC is assessed as if it were a BCTC project. As discussed further below, the JdF analysis is limited to a pricing formula proposed by Sea Breeze, which is a function of the Commission-determined VITR costs and other system benefits of JdF. For the purposes of this analysis, the lump sum payment method proposed by Sea Breeze is adopted (Exhibit B2-64, BCUC 4.155.1). Unless otherwise stated, all costs used in the comparisons in this Section have been rounded to the nearest $500,000 and are in real $2005. Totals may not be exact due to rounding errors.

### 7.1 Project Schedules and Obstacles to Completion

#### 7.1.1 VITR Schedule

The schedule for VITR in the Application indicates a Commission Decision by February 17, 2006, and an in-service date of October 31, 2008. During the hearing, BCTC stated that the risk of delays to an October 2008 in-service date for Option 1 is low, as it has all the ROWs that are required, the project does not involve new technology, and major issues are not expected to be raised in the environmental review process. BCTC indicated that it believed it could also complete VITR Options 2 or 3 by October 2008, but recognized that the risks were greater due to potential problems obtaining new ROWs (T8:1059).

On May 4, 2006, BCTC filed a report on cable tenders for VITR (Exhibit B1-135). In that report, BCTC stated that it has determined that:

> "(i) it is worthwhile proceeding with a detailed technical, commercial and legal evaluation and, if necessary, clarification of tender or tenders with the objective of awarding a contract;
>
> (ii) the contract award value is not expected to be any higher than the lowest read out cost; and
>
> (iii) BCTC anticipates that a contract award will result in satisfactory performance, schedule and commercial arrangements."

Sea Breeze submits there is a risk of delay in VITR's in-service date as a result of delays in the cable tendering process. Sea Breeze also argues there is a risk of extensive delay in the VITR schedule due to public opposition and legal holdups that stakeholders may pursue (Sea Breeze Argument, para. 23). BC Hydro responds that its ROW agreement provides it with an unfettered right to construct the Option 1 facilities, while Sea Breeze has no ROW for either VIC or JdF. BC Hydro states that the Commission must assume it will take the steps necessary to secure service for its customers, but acknowledges that the uncertainty regarding ROWs pertaining to Option 2 may influence the Commission's deliberations with respect to timing (BC Hydro Argument, para. 22-23).

### 7.1.2 VIC Schedule

The schedule for VIC in the Sea Breeze VIC Application indicated a Commission Decision by March 2006 and an in-service date of March 16, 2008 (Exhibit B2-1, Figure 3.7.1). On March 1, 2006, Sea Breeze withdrew its VIC Application. Sea Breeze argues that if a streamlined process were used for a future BCTC CPCN application for VIC and considering the work that Sea

Breeze has already done on the project, VIC could be available in a timeframe sufficient to meet the needs of Vancouver Island (Sea Breeze Argument, para. 383).

### 7.1.3 JdF Schedule

In this Section, the schedule for JdF is considered on the basis of an assumption that financing for the project will be available as needed. The Commission Panel recognizes that financing for the project depends on several factors, including the negotiation of a service contract with BCTC that generates sufficient revenue to Sea Breeze.

Sea Breeze provided a revised Gantt chart for JdF indicating an NEB CPCN decision by July 21, 2006, completion of permitting by the end of 2006 and an in-service date of April 28, 2008 (Exhibit C31-57, Undertaking T36:6840). Sea Breeze states that JdF is on schedule to meet, at the outside, an in-service date of October 2008, and expects its application to the NEB to proceed smoothly. Although there are two land owners with whom it has not yet reached land use agreements, under the *NEB Act* it would have the right to expropriate an interest in the land (Sea Breeze Argument, para. 122-125).

A number of permits are required from United States authorities, but Sea Breeze states that it does not expect any problems obtaining the necessary U.S. permits. Sea Breeze also maintains that upgrades to the BPA system that are needed to deliver power to Port Angeles will be in place by October 2008. Sea Breeze rejects, as speculation, BCTC’s argument that a 500 kV line upgrade on the Olympic Peninsula will be needed and that a full NEPA process may be needed. The studies that are required in support of the request to interconnect JdF to the BPA system at Port Angeles have been completed or are in progress. Sea Breeze states that the BPA System Impact Study identified the required network upgrades on the Olympic Peninsula so that 550 MW of power can be delivered to and from Port Angeles, as well as the local interconnection costs for JdF. Sea Breeze has informed BPA that Sea Breeze will pay for all of these upgrades, and it estimates these facilities will cost US$75 to 80 million (Sea Breeze Argument, para. 134, 136).

BPA submitted a letter that cast doubt on the schedule that Sea Breeze put forward for JdF, commented on the unlikelihood of altering Canadian Entitlement delivery points, and discussed the upgrades within the BPA system that would be necessary to support JdF (Exhibit D-71). Specifically, BPA estimated that the earliest that the NEPA process for JdF could be satisfied would be early 2007, not June 2006 as claimed by Sea Breeze. BPA also claimed that it had only studied the effects within its own system on a small portion of the grid located on the Olympic Peninsula, and that additional system impacts attributable to JdF were likely, triggering associated upgrades.

The BPA Facility Study that is ongoing will identify from engineering and cost perspectives the specific facilities needed to interconnect JdF at Port Angeles. To also obtain a Facility Study for the BPA system upgrades, Sea Breeze requested a Special Study of the upgrades in November 2005 and is working with BPA to finalize the terms and scope of this latter study (T36:6998). Sea Breeze expects that the Special Study will not identify that further upgrades are needed on the BPA system. Sea Breeze generally relies on the evidence of its witnesses and their experience dealing with BPA and the development of other projects in the U.S. (Sea Breeze Argument, para. 137-140).

The JIESC's attempts to get certainty on the cost of ABB's HVDC Light® offering for either VIC or JdF were unsuccessful as Sea Breeze was unable to produce any written offer from ABB providing an estimate for the HVDC Light® system (Exhibit C31-57, Undertaking T30:5676). ABB was able to confirm its ability to supply, install and commission an HVDC Light® system within 20 to 24 months following the execution of an EPC contract (T32:6034).

BCTC raises a number of concerns about slippage in the schedule for JdF, whether necessary permits would be in place for JdF and whether the upgrades on the Olympic peninsula would be financed and built within the schedule proposed by Sea Breeze (BCTC Argument, para. 83-86). Sea Breeze responds that BCTC's concern with JdF's schedule is not based on evidence in the proceeding and ignores the availability of bridging measures and performance guarantees. Sea Breeze submits the bridging measures can be relied on for up to three years, and repeats evidence from EIF that EIF believes a performance bond of $10 to $20 million is appropriate and feasible for JdF (Sea Breeze Argument, para. 115-116; Exhibit C31-57, Undertaking T40:7505-7506).

BC Hydro argues that Sea Breeze would not be able to commit to JdF going ahead until the milestones in the DLA are met and financial close of the project has occurred. In BC Hydro's view, one essential milestone is completion of the requirements of the NEPA. The NEPA process cannot be completed until early 2007 and so an unconditional contract between BCTC and Sea Breeze cannot occur until some time after early 2007 at the soonest (BC Hydro Argument, para. 92-95).

Sea Breeze replies that the presence of milestones in the DLA with EIF are guidelines and that EIF could commit to financing JdF before certain conditions precedent, including those relating to permitting, were satisfied (Sea Breeze Reply, para. 30).

BC Hydro outlines a sequence of steps related to environmental assessment, financial closing and project construction that indicates to it that JdF could not be completed until sometime between December 2008 and March 2009 (BC Hydro Reply, para. 51).

Sea Breeze submits that many of the elements of JdF that BC Hydro refers to in its Argument are issues that would arise in virtually any proposal for investor-funded merchant transmission and that adopting BC Hydro's approach to the matter will preclude considering merchant transmission as an alternative. Sea Breeze also notes that BPA will be required to act in accordance with its tariff and cannot refuse to interconnect with JdF and to make system upgrades that are needed (Sea Breeze Reply, para. 18, 28, 31).

**Commission Determination**

There are two conforming tenders to supply and install the submarine cable in compliance with the proposed VITR schedule. The Commission Panel concludes that there is relatively low risk that VITR will not be completed by October 2008 if it is built using the Option 1 overhead routing for Segment 2. The risk of not meeting the October 2008 in-service date is somewhat higher for VITR Options 2 and 3.

With the withdrawal of the Sea Breeze VIC Application, it would appear that VIC can only be assessed as a BCTC project. In this circumstance, BCTC would appear to have access to BC Hydro ROWs and other property, and should be able to expropriate property rights where necessary. Also, financing of the project should not be in question. Therefore, the risk of delays to the completion of VIC should be generally similar to the risk for VITR Options 2 and 3 except for additional risks for VIC due to any differences in the amount of work that the proponents have done to advance their respective projects and any complications arising from BCTC taking over the project. The Commission Panel concludes the risk of VIC not meeting an October 2008 in-service date is somewhat greater than the risk for VITR Options 2 and 3 and considerably greater than Option 1.

The parties hold sharply differing views on the risk that JdF will not meet an October 2008 in-service date. It would have been helpful to have more evidence directly from BPA about the interconnection and upgrade facilities needed for JdF, the studies and approvals related for these upgrades, and the commitments needed to proceed with them. The Special Study to determine the cost, construction schedule, and other details for the specific upgrades to the BPA system has been requested, but the terms of the study have not yet been finalized (Sea Breeze Argument, para.139), and there is uncertainty about the complete scope of these upgrades and the permitting requirements for them. Although BPA casts doubt on whether the identified upgrades are all that are required to support transmission capacity to JdF, Sea Breeze is confident that any additional upgrades will increase the available path rating, from which they will derive additional benefits (T35:6791-6793). Nevertheless, the Commission Panel concludes it is possible to compare the risks of delay for JdF and VITR.

Sea Breeze expresses confidence that JdF can be in-service by October 2008, and BCTC takes a similar position for VITR Options 2 and 3. The two projects have important similarities; both involve submarine cables, expropriation may be needed to obtain access to land rights and the permitting requirements for both are underway but far from complete. On this basis, the Commission Panel concludes that the risk of delay for JdF is similar to VITR Options 2 and 3, and higher than for VITR Option 1. However, JdF also requires extensive permitting in the U.S, upgrading of the BPA system, negotiation of a service agreement with BCTC, and effective sequencing of permitting with approvals of financing. As identified earlier, this assessment of the risk of delay for JdF does not consider the possibility that, due to the outcome of negotiations with BCTC or for other reasons, Sea Breeze will not be able to obtain financing for the project. In this circumstance, the Commission Panel concludes that the risk that JdF, including necessary upgrades to the BPA system, will not meet an October 2008 in-service date is considerably greater than the schedule risk for VITR Options 2 and 3.

In summary, the Commission Panel concludes that VITR Option 1 has the lowest risk for an October 2008 in-service date, followed in order by VITR with Options 2 and 3 through South Delta, VIC, and finally, JdF. The additional uncertainties related to JdF lead the Commission Panel to conclude that there is a considerable difference in the risk of delay between VITR Option 1 and JdF.

### 7.2 Reliability

As discussed in Section 4, reliability is determined by two aspects, namely, adequacy and security as defined by the NERC/WECC Planning Standards. Adequacy can be evaluated on both deterministic and probabilistic criteria. VITR, VIC and JdF are assessed against deterministic criteria. The record on probabilistic evaluation and the assessment of security was less complete, especially for JdF.

The probabilities of failure for individual system elements used in the EENS studies were taken from statistical data where available, and were typically less than five percent. The probability of simultaneous failures involving two system elements was determined by multiplying individual probabilities. Therefore, simultaneous two element failure probabilities were typically less than 0.25 percent. The transmission capacity loss for multiple element outages was determined additively, so the lost transmission capacity would increase for outages involving parallel system elements while the probability decreased. As observed by several parties, this made the results of the EENS studies more sensitive to the transmission capacity ratings as compared to the failure probabilities of comparable projects. Sea Breeze categorically rejects BCTC's EENS analysis, but does not suggest any other probabilistic analytical tool for the assessment of reliability (Sea Breeze Argument, App. E, para. 25).

BCTC conducted several EENS studies in support of its system planning tasks and/or in response to information requests. These studies are collectively referred to as the *Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project.* Part I of the study is subtitled *Reliability Improvements due to VITR* (Exhibit B1-47, BCUC 3.186.1), Part II is subtitled *Comparison between VITR and Sea Breeze HVDC Light® Options* (Exhibit B1-47, BCUC 3.186.2), and Part IV is subtitled *Effects of Existing HVDC on VI Power Supply Reliability* (Exhibit B1-65).

### 7.2.1 VITR Reliability

BCTC plans the bulk transmission system, including connections to Vancouver Island, to meet NERC/WECC Planning Standards. BCTC states that based on the planning standards and outage events in the past 10 years, retaining a synchronous connection to the mainland system is also critical for secure Vancouver Island operation (Exhibit B1-1, p. 92).

BCTC expects VITR to have acceptable reliability. A single cable failure of the VITR circuit could result in the circuit being out-of-service for up to three months. This consequence is severe, but should be acceptable because Vancouver Island can be supplied through the 500 kV circuits during the period that the VITR circuit is out-of-service. A spare phase cable would have little impact on EENS on Vancouver Island, and a spare phase cable would be costly. BCTC does not recommend the installation of a spare phase cable (Exhibit B1-1, App. A of App. C, p. 9).

The PST can be out-of-service for a long duration if severe damage occurs inside the transformer. VITR without the PST (N-1 condition) is able to operate within its thermal limit during most of the time until another major outage (N-2 condition). In such an N-2 condition, if overloading of the VITR 230 kV cables occurs, the VIT buses can be split to allow the VITR

230 kV circuit to solely supply the VIT transformers T5 and T6. In such an event, the VITR 230 kV circuit will still be able to supply up to 400 MW to Vancouver Island. A spare PST is not recommended because of favourable operating experience with a similar PST installed at the Nelway Substation. The probability of PST failure is extremely low and the low probability can be mitigated by operational measures (Exhibit B1-1, App. A of App. C, pp. 9-10).

Sea Breeze states that the reliability of VITR is limited by its use of a PST. Sea Breeze observes that when the VITR PST is out-of-service it cannot perform its power flow control function, and claims that the VITR 230 kV circuit would only be able to be loaded to 400 MW. In such circumstances, the Vancouver Island network would be vulnerable to a second contingency failure for an extended time (Sea Breeze Argument, para. 231, 233).

BC Hydro observes, and was supported by others (CEC Argument, para. 9), that it appears to be common ground that VITR would meet Vancouver Island’s capacity needs. BC Hydro proposes that while alternative technologies have been promoted on the basis that they might do the job more appropriately, no evidence was led to suggest that VITR could not itself do the job (BC Hydro Argument, para. 14). However, a dissenting view was provided by IRAHVOL. IRAHVOL contends that during winter peak periods, a prolonged N-1 condition, such as the loss of VITR, would result in load shedding (IRAHVOL Argument, p. 32). IRAHVOL goes on to describe such a situation and ascribes a loading of 1300 MW to the 500 kV interface (IRAHVOL Argument, p. 33). In Reply, BCTC observes that this loading scenario actually describes an N-2 condition, and not an N-1 condition (BCTC Reply, para. 29).

IRAHVOL describes several N-2 and N-1-1 scenarios (the latter refers to an unplanned outage of one system element during planned maintenance of another element, whereas the N-2 criterion refers to an unplanned outage of two elements) and observes that if it were necessary to shed load in advance of an N-2 or an N-1-1 contingency (after an N-1) in order to prevent overloading of the VITR cable, this would be a violation of transmission planning criteria (IRAHVOL Argument, p. 37). In Reply, BCTC observes that for the situations described, the system has survived the initial N-1 event, and it is allowable to take operational measures to prepare for an N-2 event (BCTC Reply, para. 29; T10:1583-1584).

IRAHVOL also observes that probabilistic EENS studies were carried out to compare the adequacy component of reliability of VITR and VIC for Vancouver Island; however, there were no dynamic performance studies of VIC, JdF and VITR under N-1 or N-2 conditions to compare the security component of reliability (IRAHVOL Argument, p. 36). BCTC provided a study, which it claimed represented a dynamic analysis for VITR, and stated that the results of the study showed that for an N-2 condition involving the two 500 kV circuits, there was no transient instability and although significant loading shedding was required, it could be accomplished within the allowable transient overload capability of the VITR 230 kV cable (Exhibit B1-44, Sea Breeze 2.39.6).

Sea Breeze maintains that BCTC has failed to adequately study voltage stability on Vancouver Island, and furthermore that there is risk of voltage instability in the Vancouver Island transmission system during the life of VITR that would not exist if JdF or VIC were selected (Sea Breeze Argument, App. E, para. 4, 6).

### 7.2.2 VIC Reliability

Sea Breeze submits that VIC will satisfy Vancouver Island's reliable transmission capacity needs by adding a 540 MW capacity transmission line between major substations in the Lower Mainland and Vancouver Island. VIC would also offer the black start capabilities of the HVDC Light® system, which Sea Breeze submits can make a critical difference in reliability in contingency situations (Sea Breeze Argument, para. 358).

BCTC does not suggest the HVDC Light® system used for either VIC or JdF is inherently unreliable, nor is there any dispute amongst the Intervenors regarding the ability of either project's HVDC Light® system to meet deterministic adequacy criteria (BCTC Argument, para. 38). For instance, CEC believes that VIC is a viable alternative to VITR and would meet the requirements and need for supply to Vancouver Island (CEC Argument, para. 52). However, BCTC's probabilistic EENS comparison of VITR and VIC demonstrated that VITR would provide better reliability (Exhibit B1-47, BCUC 3.186.2). The EENS study used a pessimistic failure rate for VITR. BCTC claims that with the same pessimistic assumption for the failure rate of the submarine cable in VIC, VITR will result in about 26 to 32 percent higher Vancouver Island supply reliability. Even if an optimistic assumption for the failure rate for VIC is used, VITR will still have about 15 to 18 percent higher Vancouver Island supply reliability.

IRAHVOL contends that VIC would provide better reliability to Vancouver Island by responding faster and requiring less load shedding under contingencies. IRAHVOL states further that VIC and JdF would provide even better reliability by providing the transmission capacity required during contingencies, by diversifying the source of transmission capacity, and by encouraging future on-Island generation (IRAHVOL Argument, p. 42). BCTC disputes this, stating that compared to VIC or JdF under multiple contingencies, VITR would result in less load shedding as VITR provides more continuous transmission capacity as well as significant overload capability for a short time (BCTC Reply, para. 30).

#### 7.2.3 JdF Reliability

Sea Breeze submits that JdF will satisfy the present need for additional reliable transmission capacity to Vancouver Island provided that JdF is accompanied by, among other things, the completion of upgrades to the BPA system, and the ability to ensure a sufficient firm supply of power can be arranged at Port Angeles (Sea Breeze Argument, para. 71).

As a result of the interconnection request made by Sea Breeze to BPA in respect of JdF pursuant to BPA's OATT, BPA has completed a Feasibility Study and a System Impact Study (Sea Breeze Argument, para. 133). The System Impact Study identified all of the network upgrades that are necessary to ensure that 550 MW of power can be delivered to and from the Port Angeles interconnection point, and was demonstrated by summer and winter contingency nomograms showing JdF transfer capability as a function of Olympic Peninsula loads before and after network upgrades (Exhibit B2-20, BCTC 1.26.7). The engineering and cost issues related to the specific facilities needed to interconnect JdF at Port Angeles are presently being addressed by Facility Studies (Sea Breeze Argument, para. 137). However, the Facility Studies do not address the required network upgrades beyond the immediate interconnection. The engineering and cost issues related to the network upgrades will be addressed by a Special Facility Study, the terms of which are still under negotiation (Sea Breeze Argument, para. 139). Sea Breeze submits that once the Special Facility Study is finished and the necessary engineering and cost requirements for the upgrades are established, it would be completely illogical and inconceivable that BPA would refuse to accept significant upgrades to its system paid for by Sea Breeze, when the upgrades would inevitably result in greater reliability to a weak part of BPA's system. The interconnection of JdF at Port Angeles will change the reliability classification of BPA's Olympic Pennisula system from a "radial" to an "interconnected" grid. Sea Breeze submits that "…BPA will be required to plan and implement measures to accommodate common mode failure contingencies pursuant to WECC and NERC requirements" (Sea Breeze Argument, para. 145).

Sea Breeze urges the Commission to have confidence that a sufficiently secure supply of power can always be arranged at Port Angeles to allow JdF to be used to satisfy Vancouver Island's reliability needs (Sea Breeze Argument, para. 147). Sea Breeze further argues that BCTC would only need assurance that, under N-1 conditions, JdF can provide the support required to ensure reliable supply for Vancouver Island load (Sea Breeze Argument, para. 150). From a reliability perspective, Sea Breeze proposes that power would only actually be required to be carried to Vancouver Island via JdF during such months of the year when total Vancouver Island demand may exceed the approximately 2000 MW of total dependable transmission capacity available from the Cheekeye-Dunsmuir lines and on-Island generation. Sea Breeze states that in the earlier years of JdF's operation, this requirement would only occur at or near peak and possibly during scheduled maintenance (Sea Breeze Argument, para. 151). Sea Breeze acknowledges once JdF is in place, the actual operation would be driven by need to optimize system operations rather than exclusively for reliability (Sea Breeze Argument, para. 153). Finally, JdF also offers the black start capabilities of the HVDC Light® system, which Sea Breeze submits has similar reliability benefits as identified above for VIC.

BCTC observes, and is supported by the JIESC, that in order for JdF to satisfy NERC/WECC Planning Standards, BCTC would need to ensure that firm contracted transmission capacity was in place on the BPA system (JIESC Argument, para. 98). The only BPA services that are available to provide firm transmission capacity are point-to-point service (wheeling) and network integration service (BCTC Argument, para. 75-76). Although the full rated transmission capacity of JdF may not be required immediately for reliability requirements on Vancouver Island, BCTC believes that it would still need to contract for sufficient firm transmission capacity to safely provide for a number of years of load growth, and to ensure that the transmission capacity would not be contracted to others, and thus unavailable to BCTC (Exhibit B1-39, pp. 26-27). Beyond the requirement for firm transmission capacity on the BPA system to Port Angeles, BCTC did not provide any quantitative reliability adequacy assessments or comparisons of JdF, nor did BCTC identify any other inherent violations of adequacy criteria.

BC Hydro claims the evidence disclosed that the existing BPA system was inadequate to provide firm power (T35:6764). BC Hydro proposes that the Commission has virtually no evidence upon which to reach a conclusion with respect to the state of the reinforcement efforts of BPA and how likely they are to happen (BC Hydro Argument, para. 64). This view received support from CEC. CEC believes that there are sufficient risks that it would not be prudent to pursue JdF on its own without having a CPCN in hand for VITR (CEC Argument, para. 110).

**Commission Determination**

The Commission Panel accepts the deterministic adequacy components of reliability for supply to Vancouver Island for both VITR and VIC satisfy the NERC/WECC Planning Standards. JdF could also satisfy the NERC/WECC Planning Standards deterministic reliability criteria for supply to Vancouver Island, provided that significant network upgrades are completed within the BPA transmission system.

The Commission Panel accepts BCTC's EENS studies as an appropriate analysis tool for the probabilistic evaluation of reliability, and further accepts that these studies showed better reliability with VITR and the PST than with VIC, including the failure rate data for the PST. Both projects contain elements for which the statistical failure rates are based largely on assumptions or limited population sizes from which to derive such statistical data. According to BCTC, the results of its reliability studies indicate that the 230 kV ac line will provide about 26 to 32 percent higher Vancouver Island supply reliability than VIC. While it may be correct to say that the EENS associated with VIC is 26 to 32 percent higher than that associated with VITR (based on the "pessimistic" assumptions about VIC that BCTC used in the EENS study), the Commission Panel does not accept the statement that VITR's reliability is 26 to 32 percent higher than that of VIC.

The table below shows the results of Part II of the EENS study that, according to BCTC, was intended to compare the reliability of VIC and VITR. Column B contains a forecast of on-Island energy consumption, calculated by multiplying the forecast peak load (Exhibit B1-47, BCUC 3.186.2, App. C, p. 18), the number of hours in the year, and 62 percent, which was the average Vancouver Island load factor between January 1, 2002 and July 31, 2005 (Exhibit B1-6A, BCUC 1.19.5). Columns C, D, and F come directly from Table B in Part II of the EENS study (Exhibit B1-47, BCUC 3.186.2). Columns G and H are calculated using:

$$\text{Reliability} = \frac{\text{Energy Served}}{\text{Energy Demanded}} = \frac{\text{Vancouver Island Energy - EENS}}{\text{Vancouver Island Energy}}$$

Column I is simply the difference between the VIC and VITR reliability values expressed as a percentage of the VIC reliability. Based on a common definition of reliability, which results in values above 99 percent (Columns G and H in the table below), the differences between VIC and VITR are very small. Therefore, for the purposes of this Decision only, the Commission Panel considers the difference in the probabilistic adequacy of VITR and VIC are not large enough to be used as a selection criterion between the two projects. There is insufficient evidence from which to draw any conclusions regarding the probabilistic reliability characteristics of JdF.

**Table 7-1: EENS Study Results Comparing VITR and VIC**

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Vancouver Island Energy** | **VIC EENS (MW.h)** | **VITR EENS (MW.h)** | **EENS Diff (MW.h)** | **EENS Diff (%)** | **VIC Reliability** | **VITR Reliability** | **Reliability Diff (%)** |
| 2008 | 12,907,210 | 3,888 | 2,870 | 1,018 | 26.18 | 0.99970 | 0.99978 | -0.0079 |
| 2009 | 13,018,586 | 3,767 | 2,779 | 988 | 26.23 | 0.99971 | 0.99979 | -0.0076 |
| 2010 | 13,170,660 | 4,047 | 2,969 | 1,078 | 26.64 | 0.99969 | 0.99977 | -0.0082 |
| 2011 | 13,328,165 | 4,211 | 3,085 | 1,126 | 26.74 | 0.99968 | 0.99977 | -0.0085 |
| 2012 | 13,451,818 | 4,522 | 3,281 | 1,241 | 27.44 | 0.99966 | 0.99976 | -0.0092 |
| 2013 | 13,567,138 | 4,824 | 3,523 | 1,301 | 26.97 | 0.99964 | 0.99974 | -0.0096 |
| 2014 | 13,746,367 | 5,167 | 3,769 | 1,398 | 27.06 | 0.99962 | 0.99973 | -0.0102 |
| 2015 | 13,909,303 | 5,468 | 3,991 | 1,477 | 27.01 | 0.99961 | 0.99971 | -0.0106 |
| 2016 | 14,099,901 | 6,020 | 4,348 | 1,672 | 27.77 | 0.99957 | 0.99969 | -0.0119 |

Potential responses to N-1 conditions were described by BCTC (T10:1583-1584). Public appeal for voluntary load reduction in preparation for and protection against the next contingency following an N-1 event is an acceptable practice. The NERC/WECC Planning Standards allow for planned loss of load for N-2 conditions; however, the Commission Panel considers emergency curtailments or contractual load curtailments in response to an N-1 event, in preparation for the next contingency, to be very similar to "bridging measures" that should not be relied upon for long-term system planning.

The Commission Panel finds that BCTC has adequately assessed the dynamic performance of VITR, and accepts that VITR will have acceptable dynamic performance for the foreseeable future. There has been limited assessment of the transient characteristics of any of the projects. **The Commission Panel therefore directs BCTC to study the transient stability of the approved project and to file with the Commission by December 31, 2006, a report**

**documenting the security characteristics of the approved project and confirming that there are no other system upgrades required to ensure acceptable transient performance in the southern Vancouver Island transmission system.**

## 7.3 Capital Costs of Project Alternatives

### 7.3.1 VITR Capital Costs

In its Application, BCTC provided a P50 estimate for the capital cost for VITR of $233 million ($245 million nominal dollars) based on its preferred routing identified as Option 2 through South Delta (Exhibit B1-1, p. 103, Table 4-3). The P50 capital cost estimate for Option 1 through South Delta and the Gulf Islands was $220.5 million ($231.5 million nominal dollars). Based on the determinations in Section 6, Option 1 through South Delta and the Gulf Islands is used for the cost comparison of VITR with VIC and JdF.

The P50 capital costs of VITR include project definition costs, best estimates for project implementation costs, an allowance for overhead, estimated IDC, and a contingency. The contingency represents the difference between BCTC's best estimate of costs and a probabilistic cost estimate derived from a Monte Carlo analysis using probability distributions around individual input costs (Exhibit B1-6, BCUC 1.102.4).

The original P50 contingency for Option 1 was $16.5 million (excluding overhead and IDC). The original P90 contingency for Option 1 was $45 million (excluding overhead and IDC). The total P90 estimate for Option 1 was originally filed as $251 million ($264 million nominal dollars).

Sea Breeze estimated the expected capital cost of VITR, based on Option 2, as $290 million (nominal dollars) compared with the estimate provided by BCTC in Exhibit B1-1 of $245 million (nominal dollars) (Exhibit B2-1, p. 201, Table 4.3.1; Exhibit B1-1, p. 74, Figure 3-35). In Exhibit B1-39, BCTC discussed the various adjustments Sea Breeze had made to VITR costs in its analysis. BCTC noted that Sea Breeze appeared to have incorrectly identified Project

Definition costs and had also double counted Insurance During Construction, IDC and Communication and Control costs. In response to BCUC 4.155.1, Sea Breeze assumed a lower nominal P50 capital cost for VITR Option 2 of $281 million (Exhibit B2-64, BCUC 4.155.1). However, this was still higher than the estimate provided by BCTC. The remaining discrepancy can be explained by two factors. First, Sea Breeze added an additional $13.4 million to the Phase 1 Costs (Project Definition) of VITR, which it indicated in Exhibit B2-1 it had derived from the BCTC Capital Plan. Second, Sea Breeze assumed a VITR cost of $245 million for Option 2 was in real $2005 and inflated this value to 2009. In fact, as noted above, the quoted $245 million base cost for VITR was in nominal dollars. The Commission Panel finds no support for the higher project definition costs proposed by Sea Breeze and therefore adopts the original estimates filed by BCTC as a starting point of its comparison. In addition, the Commission Panel also considers the project definition costs for VITR as sunk and therefore not relevant to the project comparisons, except as noted below in the determination of the price for JdF.

#### 7.3.1.1 Submarine Cable Tender

The submarine cables represent more than half of the estimated capital costs for VITR and as a result the submarine cable costs were a major focus of discussion during the hearing (T8:1085-1089; T11:1685-1686). The estimated cost of submarine cables in BCTC's Application was $119 million with a P50 contingency of $12 million for an expected (P50) cable cost of $131 million, excluding overhead and IDC (Exhibit B1-44, Sea Breeze 2.45.1). The P90 contingency for submarine cables was $35 million, excluding overhead and IDC on the contingency, for an expected P90 cable cost of $154 million. The cost of submarine cable is the same for Options 1and 2 through South Delta.

In January 2006, BCTC issued a tender for the design, supply, installation, and commissioning of the submarine cable systems for VITR's Georgia Strait and Trincomali Channel crossings (Exhibits B2-58A, -58B, and -58C). On April 7, 2006, the Commission directed BCTC to file a report on the results of the cable tenders for VITR as described by the witness for BCTC at T37:7238-7246 (Exhibit A-76). On April 27, 2006, BCTC filed a letter to the Commission providing the “read-out” costs from the tenders received. One tender was from Mitsubishi Canada Limited, which quoted a price of $135.3 million for cables with polypropylene laminated paper insulation. The other tender was from Nexan Norway As, which quoted a price of $149.8 million for cables with kraft paper insulation.

Following BCTC’s April 27, 2006 letter, Sea Breeze wrote to BCTC on May 1, 2006 requesting that it provide certain additional information in its May 4, 2006 report to the Commission on the cable tender (Letter referenced in Exhibit B1-135, p. 3). In its May 4, 2006 report on the cable tenders (Exhibit B1-135), BCTC declines to provide the requested information, indicating that it had not disclosed any information—apart from the read-out costs—from one tenderer’s submission to the other tenderer. BCTC also states, based on its preliminary reviews, that it is worthwhile proceeding with further tender evaluation, that the contract award value is not expected to be any higher than the lowest read-out cost, and that it anticipates that a contract award will result in satisfactory performance, schedule, and commercial arrangements.

In its report, BCTC notes that the submarine cable cost included in VITR’s cost estimate was $119.3 million and that, with the P50 contingency provision of $12.2 million, the total forecast cable cost was $131.5 million. BCTC also indicates that following detailed evaluation and negotiations, the cable contract award value is not expected to be any higher than the lowest read out cost. BCTC did not indicate whether the quoted tender values were in nominal or real dollars. However, it compares the cable tenders to its real dollar estimates for the submarine cables ($119 million plus a contingency of $12.2 million). For the purposes of this analysis, the Commission Panel therefore assumes the tender quotes above are also in real dollars.

In response to BCTC’s May 4, 2006 report, Sea Breeze and IRAHVOL suggest there is still uncertainty regarding the final cost of the submarine cables and argue there should still be an additional contingency placed on the lowest cable tender (Sea Breeze Cable Tender Submission, May 11, 2006; IRAHVOL Response to BCTC Cable Tender, May 11, 2006). Sea Breeze submits that the limited tender information that BCTC disclosed is clearly inadequate for the purpose of the Commission carrying out a sufficiently thorough, independent assessment of the impact of the cable tender on the costs and risks associated with VITR (Sea Breeze Cable Tender

Submission, May 11, 2006, para. 31). Besides refusing to provide the information that Sea Breeze requested, Sea Breeze also submits that BCTC failed to provide critical information and analysis that its witness indicated at the hearing would be included in BCTC's report on the outcome of the cable tender. In particular, Sea Breeze asserts that BCTC failed to provide a high-level assessment of whether all tenders are technically and commercially compliant, failed to identify what some of the performance, schedule, and commercial risks may be, and failed to establish whether or not there are tenders that will satisfy the tender requirements (Sea Breeze Cable Tender Submission, May 11, 2006, para. 26).

Sea Breeze also expresses concerns that BCTC received tenders from only two cable suppliers despite having extended the closing date of the tender from March 24 to April 27, 2006. Sea Breeze cites BCTC's view that "…[t]he extension was required to ensure quality tenders from the maximum number of potential bidders" (BCTC's April 3, 2006 letter to the Commission, attached to Exhibit A-74). Sea Breeze is also concerned that BCTC did not receive tenders from three of the world's top cable manufacturers (ABB, Pirelli [now Prysmian], and J-Power Systems), and that BCTC supplied no information on the track records of the responding bidders. Finally, Sea Breeze suggests that the low level of interest among suppliers is not surprising, given the onerous risks placed on the cable manufacturer under BCTC's call for tenders. In that regard, Sea Breeze cites the manufacturer's requirement to: (i) deliver 600 MW to VIT; (ii) provide performance and contracting bonds for the three-year warranty period; (iii) verify all marine and related issues; (iv) allocate only a 3 percent variance in cable length for re-routing; and (v) pay significant liquidated damages and/or penalties for various failures.

IRAHVOL echoes Sea Breeze's concern about the limited extent of tender information disclosed by BCTC (IRAHVOL Response to BCTC Cable Tender, May 11, 2006). In IRAHVOL's view, BCTC's response to its undertaking to IRAHVOL and subsequent exchanges with Commissioner O'Hara and the Chair falls far short of the information that BCTC said it would provide with respect to the cable tenders. IRAHVOL requests that the Commission order BCTC to provide the information that it said it would, and in particular, the information referred to at T37:7240-7241.

IRAHVOL also notes that Point 4 of Exhibit B1-135 May 4, 2006 letter makes reference to a cost estimate of $119 million with a P50 contingency provision of $12.2 million for a total forecast cable cost of $131.5 million. IRAHVOL submits that, if by this reference it is to be inferred that the tender from Mitsubishi Canada Limited of $135.3 million is very close to the total forecast cable cost of $131.5 million, then such an inference is wrong. IRAHVOL states that at Line 16 of Exhibit B1-67, the price of submarine cables for Options 1 and 2 through South Delta is stated as $119 million, and that at Lines 49, 51, and 57, respectively, there are amounts for contingency, overhead, and IDC that are applicable to the project as a whole. IRAHVOL submits the contingency in Line 49 does not disappear as a result of the cable tenders because there must still be a contingency amount to cover schedule delays (related to First Nations, route opposition, regulatory approvals, and cable ship availability), metal prices, currency exchange rates, and seabed examination by the tenderer. IRAHVOL submits that, given BCTC's aversion to any type of price cap and its "grossly inadequate" proposal with respect to budget overruns, the 10 percent contingency is also grossly inadequate. It suggests that, at a bare minimum, the figure of $119 million in Exhibit B1-67 should be replaced by the $135 million figure, the 10 percent contingency should be increased to 20 percent, and corporate overhead and IDC should be recalculated using the $135 million amount.

Sea Breeze also submits that it is neither meaningful nor appropriate to draw a simple comparison between the read-out costs from the tenders and the total amount of the VITR cost estimate plus the P50 contingency provision, as BCTC has purported to do in Exhibit B1-135 (Sea Breeze Cable Tender Submission, May 11, 2006, para. 14). Sea Breeze argues that such a comparison is misleading because the fact that responses to the cable tender have now been received does not remove continuing uncertainty with respect to the cost of the VITR cable or eliminate the need for a contingency provision. Sea Breeze suggests that the basic cable tenders are still subject to numerous risks, including currency risk, commodity price risk, risks related to change orders that may become necessary during detailed design construction, and risks related to the significant prospect of delay in VITR schedule. Accordingly, to do a meaningful comparison with the VITR cost estimate plus contingency, a contingency provision must still be added to the read-out costs of the tenders.

BCTC submits that it responded fully to the Commission's request and that it did not agree to provide detailed information or analyses beyond the undertakings given (BCTC Reply Submissions on Cable Tender, May 16, 2006). In answer to IRAHVOL and Sea Breeze on these points, BCTC submits that it provided all of the information on page 3 (point 6) of its May 4, 2006 letter. Regarding the compliance of the tenders, BCTC's letter stated that it is worthwhile proceeding with a detailed technical and commercial evaluation of the tenders. In its response, BCTC also notes that the tenders are not substantially higher than the cost estimate previously produced. The $135 million for the submarine cable is higher than the P50 estimate of $131.5 million, but below the P80 estimate of $147.2 million. BCTC also notes that, as indicated in the tender document, prices are fixed once the contract is awarded, except for "equitable adjustments" that are entertained where there are changes to conditions that are not contemplated in the contract. BCTC expects any such adjustments to be minor. BCTC also indicates that it does not expect the contract price to be higher than the lowest read-out costs, and that BCTC anticipates that a contract will result in satisfactory performance, schedule, and commercial arrangements.

IRAHVOL also raises an additional concern with BCTC's cable tendering process (IRAHVOL Argument, pp. 7-8). In particular, IRAHVOL notes that under Clause FT2 of the cable tender documents (Exhibit B2-58A, p. 3-2), bidders cannot revoke their tenders for a period of 120 days following the closing date. Thus, the bidders' quotations are valid until August 25, 2006. IRAHVOL submits that the requirement to execute a contract by the end of August will force BCTC to take enormous financial risks. IRAHVOL believes that BCTC's approach of entering into a cable contract before obtaining its environmental permits/approvals is not consistent with its Enterprise Risk Management Framework, which classifies a risk of $20 million or more as a catastrophic risk that could threaten the survival of the company (Exhibit C34-16, App. A). IRAHVOL cites BCTC's acknowledgement that there are provisions in the contracts for compensation to the contractor for costs incurred prior to termination (T11:1682-1683).

Under cross-examination (T11:1681), BCTC confirmed that it intends to sign a contract with a submarine cable supplier prior to receiving its environmental permits. BCTC believes that the risk of being denied permits to place submarine cables in the existing ROW is very, very low

(T11:1682). BCTC also confirmed, however, that if it is denied a permit and access to any other route, BCTC would be faced with termination charges under the contract. If BCTC were forced to delay delivery of the cable, there would be additional costs for storage and perhaps a cost for missed reservations with the cable-laying ship (T11:1683).

**Commission Determination**

The Commission Panel has reviewed the cable tender documents and notes that tenders can be adjusted for changes in commodity prices until the time the contract is signed. Specifically, the Commission Panel notes that the cable tender provides for equitable adjustments to the submitted cable prices based on changes in the London Metal Exchange's daily closing prices for copper and lead (Exhibit B2-58A, p. 2-10, Clause IT 10.12), as well as for exchange rate changes (Exhibit B2-58A, p. 2-9, Clause IT10.11), until the date of contract execution. The Commission Panel also notes that the tenders are based on commodity prices on April 13, 2006. The Commission Panel notes that commodity prices are very volatile (Exhibit B2-63, p. 2). Commodity costs, in turn, represent a significant portion of the total anticipated cable cost. The record does not include an explicit analysis of the remaining commodity and currency risks associated with the cable tender. For the purposes of the comparisons in this Section of the Decision, the Commission Panel has included an additional contingency of 5 percent (plus associated overhead and IDC) on the lowest cable tender reported by BCTC, which the Commission Panel considers a reasonable contingency in the absence of more explicit information.

In addition to the currency and commodity price risks, which will exist only until contract signing, the Commission Panel agrees with IRAHVOL and Sea Breeze that there are other, ongoing cable-related risks as well (such as those arising from change orders, cable re-routing, and schedule changes). However, given that an additional level of price certainty has been achieved through the cable tender, the Commission Panel does not accept IRAHVOL's argument that the contingency amount should be increased to 20 percent.

The Commission Panel has applied the additional 5 percent contingency on the lowest cable tender solely for the purposes of comparing VITR with VIC and JdF. The Commission Panel would expect the cable tender price could be fixed prior to finalizing any pricing arrangement for JdF, if JdF were selected as the preferred alternatives to VITR. Further, the Commission Panel would expect BCTC to provide an estimate and justification for any ongoing contingency required for the submarine cable portions of VITR, following execution of the cable contract.

Using the lowest cable tender plus an additional contingency of 5 percent ($135 million plus $6.5 million plus overhead and IDC on the contingency) produces a revised P50 cost estimate for Option 1 of $232 million (versus the original estimate of $220.5 million). Assuming there is no further uncertainty in submarine cable costs and therefore no further contingency is required, the revised P90 estimate for Option 1 becomes $238.5 million (versus the original P90 estimate of $251 million). Fixing the cable tender produces a much larger reduction in the P90 estimate because the cable tender contingency represents more than 75 percent of the P90 contingency for VITR Option 1 through South Delta.

With respect IRAHVOL's concern about the risk associated with BCTC signing a contract for the submarine cable prior to receiving its environmental permits, the Commission Panel considers the risk to be relatively low. The Commission Panel notes that the permit sought is for the use of an existing ROW; therefore, the Commission Panel expects that, while BCTC may be required to take certain steps to mitigate any of VITR's environmental impacts, outright rejection of the project seems unlikely. Even if the project were to be rejected in its current form, the probability that an environmental permit will be denied on any and all possible marine routes is extremely low. In any event, the Commission Panel notes it is the responsibility of BCTC to consider and manage this risk and any costs that may be recovered from ratepayers would be subject to a future prudency review. The Commission Panel therefore makes no determinations or directions with respect to the acceptability of this risk, which is not required for the purposes of its determination of whether a CPCN for VITR is in the public interest.

With respect to other concerns raised by Sea Breeze and IRAHVOL regarding the cable tender process and report, the Commission Panel does not see any need for further information on the cable tender to render a determination in this proceeding. The Commission Panel considers it the responsibility of BCTC management to develop and execute a tender process, and does not consider the number of bidders in this case as necessarily indicative of problems with the process or as relevant to its determinations with respect to the overall merits of the project.

In conclusion, for the purposes of evaluating project alternatives, the Commission Panel accepts the original P50 and P90 cost estimates for Option 1 filed by BCTC, adjusted to reflect the lowest cable tender plus an additional contingency of 5 percent (plus associated overhead and IDC) on the submarine cable. For the purposes of the comparisons in this Section of the Decision, the Commission Panel also excludes the Project Definition costs from the cost of VITR as it considers these costs sunk. As noted below, the Commission Panel continues to include these costs in the price estimate for JdF as they were included in the pricing proposals filed by Sea Breeze. After removing sunk project definition costs for VITR ($10 million plus $2 million for overhead and IDC) and adjusting for the cable tenders, the P50 and P90 estimates for VITR (based on Option 1 through South Delta) become $220 million and $226.5 million, respectively. The difference between the P50 and P90 estimates for VITR is substantially reduced as a result of the reduction in the submarine cable contingency, which was responsible for more than 50 percent of the contingency in BCTC's P50 estimate and more than 75 percent of the contingency in BCTC's P90 estimate.

### 7.3.2 VIC Capital Costs

Sea Breeze initially estimated a direct capital cost for VIC of $346 million. (Exhibit B2-1, p. 201, Table 4.3.1). Sea Breeze provided a P90 estimate for VIC of $361 million (Exhibit B2-35, BCUC 2.90.2 ). The values in Exhibit B2-1 and by extension B2-35 are in real $2005 (Exhibit B2-8, BCUC 1.73.1). In Exhibit B2-64 (BCUC 4.155.1) Sea Breeze used a direct cost for VIC of $360.6 million ($377 million in nominal dollars). BCTC suggests that Sea Breeze has revised the capital cost estimates for VIC in response to BCUC 4.155.1 (BCTC Argument, para. 53). The capital cost used for VIC in BCUC 4.155.1 is consistent with the P90 estimates for VIC filed in Exhibit B2-35 ($361 million real $2005). However, it is not clear why Sea Breeze would use a P90 estimate for VIC, when it used the P50 estimate for VITR. Sea Breeze's filing provides no detailed explanation regarding the estimates used in Exhibit B2-64, except a reference in the notes that it has made minor adjustments to project development and O&M costs for VIC. Given the ambiguity regarding the type of estimate provided by Sea Breeze in response to BCUC 4.155.1 and the absence of a clear explanation of the changes in its estimate, the Commission Panel relies on the original P50 and P90 cost estimates provided by Sea Breeze as the basis for its comparison of VITR with VIC.

BCTC's initial assessment of VIC was set out in Exhibit B1-39. In Argument, BCTC suggests that Sea Breeze's cost estimates for VIC carry greater uncertainty than BCTC's estimates for VITR largely because Sea Breeze has not conducted the level of study and analysis of VIC that BCTC has in respect of VITR. Specifically, BCTC maintains that Sea Breeze's capital cost estimate does not appear to include appropriate amounts for duties, ROW acquisition, the cost and manufacture and storage of spare cables, IDC and contingency (BCTC Argument, p. 21, para. 53). The CEC agree with BCTC that Sea Breeze's cost estimates for VIC do not include an adequate assessment of duties, ROW acquisition, and interest during construction (CEC Argument, p. 14).

BCTC, together with several Intervenors, argue that there is still considerable uncertainty over ABB's EPC estimate for HVDC Light® technology. In cross-examination, the JIESC tested the accuracy of ABB's assurances regarding the costs of HVDC Light® technology (T30:5676). Based on the responses and undertakings, the JIESC submits the Commission should not conclude that HVDC Light® technology is the better alternative without more solid assurance of cost estimates (JIESC Argument, para. 81). BC Hydro rejects VIC entirely as a viable alternative and did not address the cost estimates for VIC specifically. However, BC Hydro submits that in respect to JdF, which is also based on ABB's HVDC Light® technology, there is no evidence on the record that Sea Breeze has received a budgetary estimate from ABB for the technology and does not have a contractually firm price from ABB for a project (BC Hydro Argument, para. 81). BC Hydro notes that although Sea Breeze asserted that the estimates it received from ABB had an accuracy of +/- 15 percent, it was not able to produce any documentation to support this claim.

The Commission Panel agrees with BCTC and other Intervenors that Sea Breeze has probably underestimated the level of uncertainty in VIC capital costs. However, for the purposes of this comparison, the Commission Panel has adopted the original estimates prepared by Sea Breeze. While this tends to favour VIC in the analysis, as shown further below this has little impact on the Commission Panel's final conclusion regarding VIC.

### 7.3.3 JdF Capital Costs

The JdF is a merchant transmission facility. Because the project also crosses an international boundary, JdF would not be directly regulated by the BCUC. Rather BCTC would buy or lease transmission capacity from Sea Breeze. Sea Breeze provided several payment options for JdF that are based on the "before" (with VITR) and "after" (with JdF replacing VITR) costs to ratepayers. The two distinct approaches are a) an annual payment based on 75 percent of the Commission-determined annual cost of service for VITR, including an allowance for indirect costs, or b) a lump sum payment (or an equivalent annuity) based on 75 percent of the Commission-determined present value of the indirect and indirect VITR capital costs (Exhibit B2-64, BCUC 4.155.1). The Commission Panel notes that the cost to ratepayers under the cost of service formula and the lump sum formula could differ as a result the inclusion of direct O&M and taxes in the cost of service formula. In addition, the cost of service formula would be sensitive to the financing assumptions for VITR. For the purposes of its initial comparisons, the Commission Panel has adopted the second pricing formula proposed by Sea Breeze, which assumes a lump sum payment equivalent to 75 percent of the direct and indirect capital costs for VITR, as a basis for the comparisons.

BCTC, BC Hydro and other Intervenors also raised questions during the proceeding about whether the pricing formula proposed by Sea Breeze would be sufficient to secure financing for JdF. The Commission Panel addresses this question in Section 8 of the Decision.

Sea Breeze used the P50 estimate for VITR when calculating the price of JdF (Exhibit B2-64, BCUC 4.155.1). However, it also inflated the nominal estimate, effectively double counting inflation. In Exhibit C31-57, Sea Breeze outlines four alternative pricing scenarios in which JdF could still be viable (Exhibit C31-57, Undertaking at T36:6857-6858, 7037, 7091-7093). The first one would be based on a higher VITR cost, for example if the Commission Panel determined that a P80 or P90 VITR number was a more appropriate basis for pricing JdF. The Commission Panel notes that using the P50 or P90 estimate for VITR has very little effect on the price of JdF or benefits to ratepayers after considering the reduced contingency arising from the cable tenders. Based on the P50 estimate for VITR calculated by the Commission Panel above, the lump sum payment for JdF attributable to the direct costs of VITR would be $174 million.

#### 7.3.4 Summary Comparison of Capital Costs

The table below summarizes the Commission Panel's determinations regarding the direct capital costs of VITR, VIC and JdF for comparison purposes. The capital cost for JdF reflects the lump sum payment option for JdF; it is not intended to reflect the actual capital costs of JdF. The Phase 1 Project Development costs for VITR are excluded in the cost estimate for VITR, as these are considered sunk. However, these costs have been included in the price calculation for JdF, as they were part of the pricing formula proposed by Sea Breeze.

As can be seen in the table, the capital costs of VIC are between $126 and $134.5 million higher than VITR. The Commission Panel has adopted the estimates prepared by Sea Breeze for the purposes of this comparison but agrees with BCTC and other Intervenors that the estimates for VIC have considerably more uncertainty than VITR as a result of the lack of a contractually firm price for ABB's HVDC Light® technology.

The direct costs of JdF are $46 to $51 million lower than VITR based on the lump sum pricing formula proposed by Sea Breeze. Using the P90 estimates as the basis for comparison has little impact on the magnitude of savings. However, indirect ratepayer costs and benefits must also be factored into the project comparisons.

**Table 7-2: Summary Capital Cost Comparison (PV millions $2005)**

| Capital Cost Estimates | VITR* | VIC | JdF** |
|---|---|---|---|
| P50 | $220 | $346 | $174 |
| P90 | $226.5 | $361 | $179 |
| Increase (Decrease) from VITR Baseline | | | |
| P50 | - | $126 | $(46) |
| P90 | - | $134.5 | $(51) |

* Assumes Option 1 through South Delta. Assumes lowest tender for the submarine cable plus an additional 5 percent contingency (as well as overhead and IDC on the additional contingency). Excludes VITR Phase 1 (Project Development) costs.

** Not intended to reflect the actual capital costs of JdF. Rather, this value reflects the portion of the payment sought by Sea Breeze under its proposed pricing formula that would be attributable to the direct costs of VITR. The price for JdF includes VITR project development costs.

### 7.4 O&M

In its Application, BCTC estimated incremental O&M costs for VITR of $100,000 / year in real $2005 (Exhibit B1-1, App. J, App. 4). Sea Breeze provided an estimate for the incremental O&M of VIC of $850,000 / year in real $2005 (Exhibit B2-58, BCUC 3.153.1). These estimates produce a PV (@ 6 percent) of O&M for VITR and VIC of $1.6 million and $12.8 million, respectively (Exhibit B1-61, BCUC 6.206.0).

Sea Breeze assumed real O&M costs for VITR of $220,000 / year (real $2005) (Exhibit B2-64, BCUC 4.155.1). Sea Breeze further assumed O&M costs of $900,000 per year for VIC based on 0.7 percent of estimated Station Converter Costs of $130 million. Based on these assumptions, Sea Breeze's estimate of the PV of O&M costs for VITR and VIC are $3.3 million and $13.7 million, respectively.

The Commission Panel does not consider the difference in the PV estimates of BCTC and Sea Breeze material for the purposes of this evaluation and has simply used the mid-point of the two estimates for VITR and VIC.

The lump sum pricing formula proposed by Sea Breeze does not include any allowance for O&M costs of VITR in the pricing of JdF.

**Table 7-3: Summary Comparison of O&M Costs (PV millions $2005)**

| | VITR | VIC | JdF* |
|---|---|---|---|
| BCTC estimate | $1.6 | $12.8 | |
| Sea Breeze estimate | $3.3 | $13.7 | |
| Mid-point | $2.5 | $13.3 | $0 |

* Not included in the lump sum pricing formula for JdF.

### 7.5 Taxes

The project comparisons are made on a pre-income tax basis. BCTC is not subject to income taxes and income taxes are therefore not part of the pricing formula for JdF that has been proposed by Sea Breeze.

BCTC indicated that it included Provincial Sales Tax on equipment in the original capital cost estimates for VITR. BCTC has suggested that Sea Breeze's capital cost estimates for VIC do not include a provision for Provincial Sales Tax (Exhibit B1-39, p. 19). However, the Commission Panel has adopted the estimates for VIC provided by Sea Breeze for the purposes of the capital cost comparisons.

BCTC indicated that VITR would be subject to school taxes and the 1 percent revenue grant (Exhibit B1-61, BCUC 6.206.0). BCTC assessed School Taxes at the statutory rate applicable to electric utility transmission assets (1.49 percent). BCTC applied the 1 percent revenue grant based on the average increase in revenue requirement for VITR. BCTC also included an additional 2 percent to VIC to reflect the full municipal, rural and regional taxes to which a private utility would be subject (Exhibit B1-61, BCUC 6.206.0). Given the withdrawal of Sea Breeze's CPCN, the VIC comparison is made on the basis of BCTC's tax rates. Given the higher capital costs of VIC, the project would likely incur somewhat higher taxes even under the same tax rates as VITR. However, given the complexity of the detailed calculation of taxes, the

Commission Panel has simply used the same level of taxes for VITR and VIC in the following comparison.

The Juan de Fuca project would be subject to taxes but for the purposes of this comparison, the Commission Panel uses the lump sum pricing formula proposed by Sea Breeze, which excludes ongoing taxes in the price calculation.

The table below summarizes the PV (@6 percent) of taxes for VITR and VIC (Phase 1). The taxes for VITR are based on Option 2, which are a reasonable proxy for the taxes that might result from Option 1. The column for JdF shows the payment to Sea Breeze that would be attributable to taxes on VITR. The present values are based on a 40-year period.

**Table 7-4: Summary Comparison of School Taxes and Revenue Grants (millions $2005)**

| School Taxes and Revenue Grants | VITR | VIC | JdF* |
|---|---|---|---|
| $/year | $1.8 | $1.8 | |
| PV (@6 %) | $27.5 | $27.5 | $0 |

* Taxes are not included in the lump sum payment formula for JdF.

### 7.6 Losses

In an initial comparison of VITR and VIC, BCTC assigned an incremental cost of $6.5 million to VIC to compensate for 3 MW of incremental losses over VITR (Exhibit B1-39, p. 4, Table 1; Exhibit B1-44, BCUC 3.170.1). BCTC went on to say the additional losses associated with VIC would actually be 8.5 to 9.5 MW greater than if VITR was put in place (Exhibit B1-39, p. 8). In a subsequent analysis, BCTC used ABB's technical description of HVDC Light® to perform a loss calculation based on the proposed cable sizes and lengths for VIC (Exhibit B1-47, BCUC 3.184.1, 3.184.2; Exhibit B1-56, BCUC 3.184.3 (Revised)). That analysis considered fixed losses in the HVDC Light® converters, variable losses in the cables, and system losses in the remainder of the network. The results indicated overall incremental losses in 2008 of 7.1 MW and 47.7 GW.h for VIC compared to VITR. Using a loss value of $50/MW.h, BCTC estimated the incremental cost of VIC losses over VITR losses to be $2.4 million per year, with an estimated PV (at 6 percent) of $36 million, an amount BCTC argues is more realistic (Exhibit B1-44, BCUC 3.179.1, Table 1 Restated). BCTC performed a later analysis for higher loadings of VIC and VITR, and came up with an incremental cost of VIC losses over VITR losses of $2.7 million per year (Exhibit B1-134, Undertaking T37:7229-7230).

Sea Breeze initially claimed that system losses would be lower for VIC compared with VITR (Exhibit B2-1, p. 183). Sea Breeze later stated that within the accuracy of assumptions and model uncertainty, system losses for VITR and VIC were the same within the accuracy of the assumptions (Exhibit B2-18, BCUC 1.25.1, p. 2). Throughout the proceeding, Sea Breeze put forward different estimates for losses associated with VIC.

Sea Breeze criticizes the losses analysis prepared by BCTC. Sea Breeze argues that the evaluation of HVDC Light® prepared for BCTC by Dr. Rashwan contains a deficiency with respect to assumptions about losses because he: a) considered losses on an HVDC Light® system in the context of two 330 MW blocks; b) calculated losses on the basis that the HVDC Light® system would be operated at 500 MW, when in fact the HVDC Light® system would not need to be operated at 500 MW until 2015/2016; and, c) failed to perform load flow studies to compare the losses between HVDC Light® and ac technology (Sea Breeze Argument, App. C, para. 14). Sea Breeze also argues that BCTC's initial comparison of system losses between HVDC Light® and ac technologies was similarly flawed because BCTC did not study overall system losses between HVDC Light® and VITR and when it did, the results show VIC with only 1.06 percent higher losses than VITR. Sea Breeze argues such a minor variation simply does not provide a significantly accurate factor in comparing ac and HVDC Light® technologies, especially given the impact of system data assumptions on, and the inherent accuracy limits of, the studies used (Sea Breeze Argument, App. C, para. 29).

CEC proposes that the basis for BCTC's loss calculations was for VIC to be used to supply significant amounts of power throughout the year (CEC Argument, para. 86). CEC makes no statement as to the comparative loading of VITR.

IRAHVOL disagrees with the methodology BCTC used in the calculation of the losses for VIC and VITR as presented in Exhibit B1-47, BCUC 3.184.3 where the losses of the circuit are added to the system losses with the project in-service (IRAHVOL Argument, p. 69).

With respect to JdF, Sea Breeze claims that BPA only requires real power losses compensation of 1.9 percent of energy actually delivered and that for reliability purposes, power would only be required to be delivered to Vancouver Island via JdF rarely, in contingency situations, and only when Powerex is not importing. On this basis, Sea Breeze argues the amount of power losses compensation which would necessarily have to be paid to BPA for use of JdF for the purpose of meeting Vancouver Island's reliability needs is not material (Sea Breeze Argument, para. 167).

BCTC submits that depending on how JdF is used, the system losses could be increased by up to twice the additional losses of VIC (BCTC Argument, App. B, para. 27). Without VITR, VIC or JdF, BCTC has evaluated the incremental losses on the system over the VITR case to be $2.7 million per year (Exhibit B1-56, BCUC 3.184.3 (Revised)). BCTC used an annual value of $4.8 million for the incremental cost of JdF losses over VITR losses (Exhibit B1-61, BCUC 5.205.1). Sea Breeze confirmed JdF would incur standby losses of 5 MW (T36:6967). BCTC proposed that the incremental system losses would amount to 37 MW (T36:6964); however, Sea Breeze claimed that those losses would only appear if JdF was operated only for reliability purposes, and losses resulting from actual operation would be lower than that value (T36:6965). Sea Breeze did not offer any estimate of losses resulting from the actual operation of JdF.

CEC again proposes that the basis for BCTC's loss calculations was for JdF to be used to supply significant amounts of power throughout the year (CEC Argument, para. 158). CEC makes no statement as to the comparative loading of VITR.

**Commission Determination**

The Commission Panel accepts the VITR loss calculation in Exhibit B1-56, BCUC 3.184.3 (revised) as a valid comparative baseline.

With respect to VIC losses, the analysis considered fixed losses in the HVDC Light® converters, variable losses in the cables, and system losses in the remainder of the network, as previously mentioned. The VIC variable loss calculations in Exhibit B1-47, BCUC 3.184.2 and Exhibit B1-56, BCUC 3.184.3 (revised) have had a loss factor applied that converts peak losses into average losses based on the load capacity factor. The HVDC Light® converter losses, which were confirmed to be fixed losses by Sea Breeze, are present regardless of the loading of VIC, and are considered to be present for 95 percent of the time. Furthermore, Sea Breeze has not provided an alternative calculation of the VIC system losses as calculated in Exhibit B1-56, BCUC 3.184.3 (revised). **The Commission Panel therefore accepts the VIC loss calculation in Exhibit B1-56, BCUC 3.184.3 (revised), and the annual incremental loss cost of $2.4 million per year of VIC over VITR.**

With respect to JdF losses, the Commission Panel accepts that the losses could be as high as twice the additional losses of VIC if the JdF was operated for reliability purposes only. For the purpose of losses analysis, the JdF HVDC Light® converters are assumed to be on-line 95 percent of the time, if not for reliability-related availability in the event of contingencies, then for use by parties other than BCTC and also in order to realize the other benefits attributed JDF's HVDC Light® converter at PIK. In that case, the losses would approach those calculated as the "No VITR or VIC" case in Exhibit B1-56 BCUC 3.184.3 (revised), plus 50 percent of an additional 5.5 MW and 45.8 GW.h (taken from the VIC converter fixed losses) for the PIK JdF converter to be kept in standby mode (the Port Angeles JdF converter losses would presumably accrue to the BPA system). Sea Breeze claims that JdF would be operated with consideration for system optimization, and the losses would be substantially lower. There is no evidence that describes the losses for an optimized system dispatch with the JdF element in the system. Similarly, there has been no evidence that speaks to whether B.C. system dispatch for loss optimization purposes would be constrained by conditions on the U.S. system, so a 50 percent reduction from the "No VITR or VIC" case is taken for comparison purposes. **The Commission Panel determines that a reasonable approximation for the incremental losses associated with JdF over VITR can be calculated by taking half of the incremental losses associated with the "No VITR or VIC" case in Exhibit B1-56, BCUC 3.184.3 (revised), and adding half of an additional 5.5 MW and 45.8 GW.h for the PIK JdF converter to be kept in**

**standby or on-line mode.**

The PV of incremental losses for VIC and JdF is estimated over a 40-year horizon (the project life of VIC). Sea Breeze did not include any adjustment in its pricing formula for losses. The estimated incremental losses associated with JdF are considered as part of the other costs that ratepayers would incur for the use of JdF.

**Table 7-5: Summary Loss Comparisons (PV millions $2005)***

| | VITR | VIC | JdF |
|---|---|---|---|
| MW | - | 7.1 | 10.6 |
| GW.h | - | 47.7 | 50.4 |
| $millions / year | - | $2.4 | $2.5 |
| PV (at 6 percent) | - | $36 | $37.5 |

* Incremental losses (savings) relative to VITR.

## 7.7 Other System Costs/Benefits

### 7.7.1 Seismic Strengthening of ARN Substation

BCTC claims it has no plans to upgrade the ARN Substation for VITR and if the portion of the ARN Substation connected to the VITR circuit were damaged during a seismic event, the VITR circuit could be temporarily connected directly to one of the ING-ARN 230 kV overhead circuits (Exhibit B1-6, BCUC 1.32.1). BCTC also claims that VITR meets the N-1 planning criterion despite ARN not being considered seismically secure because it is highly unlikely that a single seismic event would occur that would remove from service both VITR and the 500 kV circuits (BCTC Argument, App. B, para. 4). Alternatively, if protection against the ARN seismic risk was determined to be prudent, BCTC proposes that permanent bypass structures could be installed at a cost of approximately $100,000 to $150,000 to provide a connection if a seismic event did affect the VITR circuit at ARN (BCTC Argument, App. B, para. 5).

Sea Breeze initially claimed a $30 million benefit should be assigned to VIC for the avoidance of the need for seismic stabilization of relocation of ARN (Exhibit B2-1, pp. 199, 201). Sea Breeze acknowledges that its estimate for seismic strengthening of ARN includes costs related to keeping the existing HVDC system in place and argues there is clearly some value to avoiding the seismically vulnerable ARN, and JdF or VIC should be credited accordingly (Sea Breeze Argument, App. E, para. 23-24).

IRAHVOL submits that ARN requires upgrading because it has a low seismic withstand capability and because it is subject to flooding in the event of damage to the sea dykes and/or because of a tsunami (IRAHVOL Argument, pp. 14-20). Flooding would prevent the rapid repair of any seismic damage.

CEC agrees with BCTC that the seismic strengthening of ARN for VITR is not necessary and that if anything were to be required only the minor expenditures on the alternatives identified by BCTC should be considered (CEC Argument, para. 73).

**Commission Determination**

The Commission Panel notes that the term N-1 used throughout the hearing is described in Table 1 of the NERC/WECC Planning Standards as a Category B contingency, which is an "event resulting in the loss of single element." The term N-2 used throughout the hearing is similarly described as a Category C contingency, which is "event(s) resulting in the loss of two or more (multiple) elements". Therefore, if a single seismic event causes multiple system components to fail, a planned loss of load is allowable under the standards.

The Commission Panel accepts BCTC's plans and ability to construct a temporary bypass around ARN Substation to connect the VITR line to an ING-ARN 230 kV line in the event of any type of failure of the VITR line termination equipment at ARN. **The Commission Panel determines it is not prudent to construct a permanent bypass facility at ARN to enable the connection of the VITR line to an ING-ARN 230 kV line, and does not assign any monetary benefit to either JdF or VIC for avoiding any upgrade work at ARN intended to make it more secure**

**against seismic events.**

### 7.7.2 Synchronous Condensers on Vancouver Island

BCTC submits that there are no system benefits attributable to VIC or JdF in relation to the existing synchronous condensers at VIT, because VIC or JdF would not allow them to be retired. BCTC claims that the NERC/WECC Planning Standards require BCTC to plan for voltage support in the event of an outage of a VIC or JdF converter station, and the synchronous condensers are in good working condition and are a low cost source of VArs to provide this voltage support (Exhibit B1-39, p. 13). Furthermore, BCTC has no plans to retire and replace the four synchronous condensers at VIT, and when these machines do reach end of life, shunt capacitors may be an adequate replacement at a cost of approximately $2.3 million in 2008 dollars for a 100 MVAr shunt capacitor bank (T37:7181-7182; BCTC Argument, App. B, para. 8-10)

Sea Breeze initially claimed a $30.8 million benefit should be assigned to VIC for the elimination of the need for synchronous condensers on Vancouver Island (Exhibit B2-1, pp. 200-201). Sea Breeze claims that either JdF or VIC would eliminate the need for the ageing synchronous condensers on Vancouver Island and avoid the existing synchronous condenser costs, although either JdF or VIC would require a 75 MVAr shunt capacitor at PIK to ensure adequate dynamic range of the converter's reactive power capacity under heavy loading conditions (Sea Breeze Argument, App. E, para. 17-18). Sea Breeze points out that BCTC has agreed that if additional voltage support was available on Vancouver Island the synchronous condensers might not be necessary (T12:1974, 1978).

Sea Breeze also points out that loss of VITR, VIC, or JdF does not present a voltage problem on Vancouver Island in 2008 because the two 500kV transmission lines to Vancouver Island would be in-service in those situations. Voltage would be acceptable for those outages without the condensers on-line (Exhibit B1-49, BCUC 3.188.1).

Sea Breeze claims that although the synchronous condensers may currently be in good condition, they will soon need to be replaced, and under VITR, would need to be replaced by an SVC and not by shunt capacitors because shunt capacitors provide only static, and not dynamic VAr support (Sea Breeze Argument, App. E, para. 20).

BCTC does not accept that Vancouver Island could survive an outage of VIC even without the synchronous condensers in place. BCTC indicates that voltage support for the worst single contingency under either VIC or VITR is not necessary in 2008 but that these needs will increase as loads grow. BCTC's studies confirm the eventual need for contingency voltage support based on the loss of either the VITR circuit or the VIC PIK converter station and, by extension, the JdF converter station (BCTC Reply, App. B, para. 13).

CEC believes (CEC Argument, para. 76-79, 149-152) that BCTC's position that neither VIC nor JdF would have value for voltage support is not logical but it also believes that there is no current or future voltage support problem in the southern Vancouver Island transmission system with VITR. However, CEC believes that with either VIC or JdF there would be added VAr support, and therefore either project would add system benefits by allowing BCTC to avoid equipment replacement and/or to displace equipment to other locations in the system. CEC believes that there is a system benefit to be assigned to either VIC or JdF for VAr support on Vancouver Island in the amount of approximately $20 million. Furthermore, CEC believes that when JdF and VITR or VIC are combined there is a very clear case that the voltage support benefits would have significant value (CEC Argument, para. 151).

IRAHVOL questions why BCTC is not able to credit the converter at PIK for the cost or part of the cost of the replacement of the four synchronous condensers at VIT. IRAHVOL also supports the notion that it would not be possible for the synchronous condensers, at the end of their useful life, to be replaced with shunt capacitors (IRAHVOL Argument, p. 45).

**Commission Determination**

The Commission Panel notes the discussion of this issue has been closely linked to the interpretation of the "South of Cut Plane D" issue. Therefore, to keep these two issues distinct, the related issue of voltage stability in southern Vancouver Island associated with the presence of dynamic reactive support is more fully considered in Section 7.7.5, and this Section simply considers the cost of the present dynamic reactive support provided by the synchronous condensers at VIT, and whether this support can be more cost-effectively provided by other means.

The Commission Panel accepts that although the VIT synchronous condensers are not required for voltage support in 2008 for an outage of VITR or the VIC or JdF converter stations at PIK, they do provide valuable back up reactive support and may be required as loads increase. An HVDC Light® converter station at PIK would provide valuable dynamic reactive support and would displace the need for running two of the four synchronous condensers at VIT. The O&M cost of running the existing synchronous condensers is about $400,000 per year (Exhibit B1-11, Sea Breeze 1.30.4) with an additional range of losses between 5.5 GW.h and 8.4 GW.h per year depending on the dispatch of the synchronous condensers (T12:1975-1978). At a value of $50/MW.h, the losses represent an additional annual cost of $275,000 to $420,000 per year, with a mid-point of approximately $348,000. The total annual cost for O&M and losses for all four synchronous condensers is then approximately $748,000. **The Commission Panel determines that two of the four VIT synchronous condensers could be shut down in the presence of an HVDC Light® converter station at PIK, so VIC or JdF should be assigned an annual benefit of half of $748,000, or $374,000, per year for the purposes of comparative analysis against VITR, provided that sufficient static reactive support is installed in the HVDC Light® converter to allow the provision of dynamic reactive support across its full output range.**

The need for additional reactive support in southern Vancouver Island in the future, its location, its timing and whether it must be static or dynamic in nature are all highly uncertain at this time and dependent on many circumstances, including the eventual retirement of the synchronous condensers, that cannot be appropriately foreseen and modeled. Therefore, no other benefits or costs associated with reactive support in southern Vancouver Island can be applied against any of the projects under consideration.

#### 7.7.3 Retirement of HVDC Pole 1 and Pole 2

Throughout the hearing, and again in Argument, BCTC maintains that the HVDC system will be kept in-service to provide one of the "bridging measures" to meet the Vancouver Island supply deficit because it can reduce the EENS until a long-term transmission solution to Vancouver Island is put in place (Exhibit B1-65, p. 3). Furthermore, BCTC states that with VITR in-service, the HVDC system is not needed to meet the NERC/WECC Planning Standards nor is it proposed to be kept as a back-up for the VITR PST. BCTC observes it is only under multiple outages (loss of the PST and one or more elements like a 500 kV circuit) that load shedding may be required. BCTC intends to continue to maintain and operate the existing HVDC system until there is adequate favourable operating experience with the new Vancouver Island supply and, at that time, BCTC will then make a decision on whether to keep the existing HVDC system in place based on an assessment of the ongoing value and cost of the HVDC system. BCTC maintains that this would be the case regardless of the particular transmission solution that is put in place (BCTC Argument, App. B, para. 12-13).

Sea Breeze initially appears to have claimed a benefit of $23.8 million based on its assertion that BCTC would keep both Pole 1 and Pole 2 in-service for VITR, and Sea Breeze's project would avoid this requirement (Exhibit B2-1, pp. 200-201). Sea Breeze continued to claim that BCTC must keep the HVDC system operational in order to ensure reliability of supply in the event of a VITR PST failure and claimed a benefit equal to the present value of the O&M costs of the HVDC system (Exhibit B2-62, p. 4). Sea Breeze observed that although VITR technically meets N-l standards when the PST is out-of-service, the repair time for the PST is considerable, and can take 12 months or more to repair. Sea Breeze then claimed that, given the length of time that the PST could be out-of-service, to effectively meet system operating criteria BCTC would need to keep the HVDC system in-service in order to meet the VITR transmission capacity deficit resulting from the PST failure.

Sea Breeze submits that there is some benefit attributable to JdF or VIC in avoiding reliance on the PST. Sea Breeze calculates this benefit as the costs of maintaining HVDC Pole 1. Sea Breeze also submits that BCTC should be ordered to conduct further studies to determine whether an outage of the PST would be different from a contingency under JdF or VIC so as to determine whether, in comparing the projects to VITR, JdF or VIC offer a benefit in this regard (Sea Breeze Argument, App. E, para. 27).

CEC believes that BCTC's argument that they intend to keep HVDC Pole 1 and Pole 2 for back-up in the initial stages of installation and operation of VITR and would do the same for either VIC or JdF is valid and correct. CEC also believes BCTC's further intent to only operate the HVDC system beyond that point if the benefits outweigh the costs also is valid and makes sense. Therefore, CEC states there is no difference in system benefits between the projects based on the retention or removal of the HVDC system (CEC Argument, para. 80, 153).

IRAHVOL does not believe BCTC's position with respect to the HVDC Pole 1 and Pole 2. IRAHVOL believes that BCTC does not want to admit to the benefit and necessity of keeping the HVDC operational and intends to keep the existing HVDC poles operational after VITR is in-service but may not be able to do that for very long, and so BCTC will need to advance Phase 2 of VITR (IRAHVOL Argument, p. 46). IRAHVOL echoes Sea Breeze's claim that the HVDC system could be used to replace transmission capacity that would be lost in the event of a failure of the PST (T11:1642).

**Commission Determination**

The Commission Panel notes with interest the views expressed by Mr. Mansour in his opening statement during the VIGP hearing:

> "We push the limits on major equipment loading as we speak, hoping it will not impact its life cycle but it may. We rely heavily on mass-trans generation on the Island, hoping that there is enough water to last for a long duration of outage. And we rely heavily on an old HVDC system which may give up from natural causes sooner. It is not just the total outages that expose the deficiencies

> of supply to Vancouver Island. Every time we have a single outage we are exposed. Bringing the quality of supply to Vancouver Island comparable to the Mainland will not happen overnight, and will not happen with the very next project" (Quoted in IRAHVOL Argument, p. 40).

The Commission Panel agrees with IRAHVOL's assessment that coincident outages of both 500 kV circuits to Vancouver Island on average of once every 3 years appears excessive and observes that this is more frequent by a factor of 10 than is specified for Category D disturbances as per NERC/WECC Planning Standards Table W-1 (IRAHVOL Argument, p. 46). The Commission Panel similarly agrees that even though de-rated, any transmission capacity that the HVDC system can provide in an N-2 or N-1-1 event will be very valuable in reducing the extent of load-shedding required on Vancouver Island.

The Commission Panel endorses maintaining the HVDC system in particular to provide a bridging measure to meet the Vancouver Island supply deficit until a long-term transmission solution to Vancouver Island is in place, and then afterwards for as long as it continues to make operational and economic sense to do so. Furthermore, the Commission Panel considers this equally applicable whether VITR, JdF or VIC is built first; therefore, there is no benefit to be claimed by any project for the retirement of the HVDC system.

#### 7.7.4 Lower Mainland VAr Compensation

HVDC Light® converter stations can be operated to produce reactive power (VAr) for system voltage support. At high transfer levels, VAr capability is restricted, but at lower transfer levels, the potential to provide VArs to the system increases. Depending on the circumstances and system requirements, this has the potential to defer the need to install other forms of system voltage support. BCTC states that the need for additional VAr support at ING has not been confirmed, but believes that with continuing load growth in the Lower Mainland it is likely that additional VAr support will be required and that an HVDC Light® converter station at ING may be able to defer the need for these facilities (Exhibit B1-39, p. 6).

BCTC's analysis shows that VIC would defer the need for one ING SVC and one shunt capacitor bank and the VITR cable capacitance would defer the need for one ING shunt capacitor bank (Exhibit B1-49, BCUC 3.181.2). Comparing the two projects, this equates to a potential net benefit to VIC of approximately $30 million (Exhibit B1-39, p. 6), but with the assumption that VIC includes the cost of a 100 MVAr fixed shunt capacitor to offset the working range of the HVDC Light® converter station. If not, this would be an additional cost for VIC (Exhibit B1-49, BCUC 3.181.2). Since JdF would not include a converter station in the Lower Mainland, the VAr support provided by JdF at PIK would not be transferable to the Lower Mainland and there is no system benefit for Lower Mainland VAr support attributable to JdF (BCTC Argument, App. B, para. 16).

Sea Breeze initially identified a VIC benefit of $48.8 million (net of $5 million of switchable capacitors supplementing HVDC Light®) attributable to replacing the voltage support function of the Burrard Thermal Station (Exhibit B2-1, pp. 200-201). Sea Breeze continues to claim VIC would satisfy the Lower Mainland's need for additional VAr support (Sea Breeze Argument, para. 308).

CEC agrees with BCTC that VIC provides VAr support benefits to the Lower Mainland equivalent to an SVC, and that VIC should be credited the cost of the SVC equipment less the added cost of shunt capacitors, which may be required to make sure the full capability is available. CEC believes the benefit is approximately $27 million (CEC Argument, para. 74-75).

IRAHVOL noted that there might be an error in BCTC's calculations of the range of dynamic VArs (-256 not -156) provided by the HVDC Light® converter station at ING (Exhibit B1-49, BCUC 3.181.2) which if corrected, may credit VIC with the cost of an additional shunt capacitor (IRAHVOL Argument, p.45).

**Commission Determination**

The Commission Panel finds that the identification of an SVC in the 2004 BCTC Capital Plan, and its subsequent identification in the *Facilities Study For BC Hydro Distribution NITS 2004* (Exhibit B1-49, BCUC 3.169.1) is sufficient evidence for confirming the requirement for some form of additional dynamic reactive power supply in the Lower Mainland in 2009. The Commission Panel also finds that an HVDC Light® converter station located at ING can provide sufficient range for this purpose if it incorporates a 100 MVAr fixed shunt capacitor to offset the working range of the HVDC Light® converter station. The dynamic range of the HVDC Light® converter station, as identified Exhibit B1-49, BCUC 3.181.2, is adequately explained by BCTC (T37:7176-7177).

The benefit associated with the Lower Mainland reactive power support is based on the avoided cost of the SVC at ING, which is valued at $30 million in 2005 uninflated dollars ($32.2 million nominal dollars) (T37:7181). **For the purposes of project comparisons, the Commission Panel determines that a benefit of $30 million for Lower Mainland dynamic reactive power supply should be assigned to VIC as compared to VITR, and that no benefit should be assigned to JdF.**

### 7.7.5 Elimination of "South of Cut Plane D" Identified Upgrades

Cut Plane D can be thought of as an imaginary plane that "cuts through" transmission lines 2L123, 2L128, 1L115 and 1L116 just south of the Dunsmuir Substation. The Cut Plane D constraint, identified in the BCTC Information Release *Short Term Limitation of Cut-Plane D* dated June 15, 2004 ("Information Release"), arises as a result of the zero rating of the existing HVDC system in 2007 and relates to the thermal limits of the transmission system between Dunsmuir and Sahtlam substations (Exhibit B1-39, App. A). BCTC claims that either VITR or VIC will adequately address this constraint, and that the thermal limits associated with Cut Plane D are not an issue in comparing the two options (BCTC Argument, App. B, para. 18).

At first, Sea Breeze interpreted the Information Release to show that the Available Transmission Capability south of the Dunsmuir Substation would be deficient even after the installation of VITR circuit (Exhibit C31-6, p.47). Sea Breeze went on to claim that its studies showed the transmission capability problem was related to any of the transmission sections between DMR and PIK, and that additional supply at VIT would not provide an adequate solution. It stated that providing electricity supply at PIK would result in an equivalent reduction in the flow of electricity across Cut Plane D, relieve the constraint, and avoid $49 million of transmission modifications.

Later, Sea Breeze acknowledged that both VITR and VIC addressed the thermal loading constraints on Cut Plane D, but suggests that VIC also addressed voltage stability constraints while VITR did not (Exhibit B2-62, p.2). Sea Breeze claimed its studies showed that with VITR, the voltage in the Vancouver Island transmission system would drop below acceptable limits at full winter load in 2008/09, even with VITR transmitting 540 MW, and with all four VIT synchronous condensers in-service, thus violating the N-1 criterion.

Sea Breeze maintains that there is risk of voltage instability in the Vancouver Island transmission system during the life of VITR that would not exist if JdF or VIC were selected. Sea Breeze claims that BCTC does not appear to have adequately studied voltage stability and urges the Commission to order BCTC to conduct further studies to determine if and when voltage instability might arise, and if so, what benefit would be attributable to JdF or VIC given that either project would eliminate voltage instability (Sea Breeze Argument, App. E, para. 4, 13).

Sea Breeze performed a study of Vancouver Island voltage stability, and acknowledges that this study did not model the synchronous condensers at VIT (Exhibit B2-18, BCUC 1.17.1; Sea Breeze Argument, App. E, para. 8). Sea Breeze submits that the modeling used in the power flow study does not diminish the conclusion that VITR requires a significant addition to voltage support in the Victoria region by the end of the study period while VIC does not.

Sea Breeze claims that to meet the expected dynamic voltage support requirements under VITR, additions to the system would be required and suggests an SVC, with a cost of $30 to $35 million, may provide adequate voltage support.  Sea Breeze also observes that the voltage support requirements could also be met by upgrading the DMR to PIK transmission lines to 500 kV, and that BCTC has estimated the cost of the DMR to PIK upgrades to be at least $49 million (Sea Breeze Argument, App. E, para. 14).  Sea Breeze has claimed this as a benefit for both VIC and JdF (Exhibit B2-1, pp. 200-201; Sea Breeze Argument, App. E, para. 15).

BCTC claims its study results show that there are adequate existing resources on the system to supply voltage support and from a voltage stability perspective, with VITR in-service, there are adequate reactive reserves available on the system and no voltage stability issue for a number of years (BCTC Argument, App. B, para. 22).

BCTC submits that on the evidence there is no benefit attributable to either VIC or JdF for avoided costs associated with thermal limits, voltage support, or voltage stability of Cut Plane D (BCTC Reply, App. B, para. 9).  BCTC also states that in the absence of VITR, the Cut Plane D thermal constraint would still be present if JdF was used only in the event of a contingency on the system (BCTC Argument, App. B, para. 22).

CEC agrees with BCTC that the system is not deficient with either VITR or VIC and believes that JdF would not be deficient either.  However, CEC believes that having supply delivered closer to the Victoria load center has a significant system benefit value.  CEC believes that for domestic growth requirements the Cut Plane D issues are further away into the future and have a lower value than Sea Breeze estimates.  Under conditions where the export expansion Sea Breeze is trying to create takes place, CEC believes the issue would be much closer and therefore have a much higher value.  CEC believes the value could range between $25 million and $45 million and would make the assessment with the lower value (CEC Argument, para. 83, 155).

IRAHVOL acknowledges that there is disagreement between BCTC and Sea Breeze on the constraints on the circuits on Vancouver Island from DMR to PIK and suggests that only dynamic studies may be able to resolve the dispute.  IRAHVOL asserts BCTC, as the operator of the transmission system, should have evaluated the ability of HVDC Light® converter stations at different locations on Vancouver Island to improve the transfer capacity of the circuits on Vancouver Island (IRAHVOL Argument, p. 45).

**Commission Determination**

The Cut Plane D issues as described in the Information Release were concerned with the thermal loading on transmission lines south of the Dunsmuir Substation.  During the course of the hearing, the "South of Cut Plane D" issue changed to an evaluation of dynamic voltage performance and voltage stability in the southern Vancouver Island transmission system.

The Commission Panel accepts that the thermal constraints associated with Cut Plane D identified in the Information Release are adequately addressed by either VITR or VIC.  VIC may have some additional future benefits for reducing the loading on the transmission lines between PIK and Sahtlam Substation as compared to VITR, but the timing and hence value of these benefits are dependent on many system and development variables that cannot be accurately determined at this time.  Therefore, there is no additional monetary benefit assigned to VIC as compared to VITR for avoiding the D1 or D2 transmission modifications as identified in the Information Release.  If JdF is used to import energy, it may have some additional future benefits for reducing the loading on the transmission lines between PIK and Sahtlam Substation as compared to VITR.  However, if JdF is used for export, then in the absence of VIC or VITR, the loading on the transmission lines between PIK and Sahtlam Substation will increase, and trigger the need for upgrades earlier.  Further, the future allocation of these costs is also uncertain.  Given the uncertainty with respect to JdF's actual mode of operation and how the cost of any future upgrades may be allocated, there is no monetary benefit assigned to JdF as compared to VITR for avoiding the D1 or D2 transmission modifications as described in the Information Release.

The issue of voltage stability in southern Vancouver Island was not the central focus of the Cut Plane D constraint discussed in BCTC's Information Release, but rather evolved during the hearing. The issue of voltage stability is related to the issue of additional reactive support in southern Vancouver Island rather than the thermal limitations of the transmission system south of DMR. As stated previously, the location, timing and nature of additional reactive support are all highly uncertain at this time and dependent on many circumstances that cannot be appropriately foreseen and modeled. The Commission Panel accepts BCTC's assessment that there are adequate reactive reserves available on the system and that there are no voltage stability issues for a number of years. The benefits for the reactive support, and hence voltage stability benefits, provided by the VIC or JdF HVDC Light® converter stations have been appropriately captured in the assessment for the synchronous condensers on Vancouver Island, and hence no further benefit is assigned to either VIC or JdF for this characteristic.

### 7.7.6 Advancement of Second Circuit for Required Capacity

BCTC submits that the lower transmission capacity of VIC or JdF will result in a need to reinforce Vancouver Island supply at least one to two years earlier than if VITR is built. BCTC submits that the value of this transmission capacity difference is approximately $12 million (2005 dollars) which represents the PV (@6 percent) of advancing the implementation of a second 550 MW HVDC Light® circuit from 2017 to 2016 (Exhibit B1-44, BCUC 3.179.1; Exhibit B1-39, p. 25). Advancement by two years, which may be necessary based on timing and load growth would increase the advancement cost to approximately $24 million (Exhibit B1-44, BCUC 3.179.3; BCTC Argument, App. B, para. 29).

CEC believes that BCTC is correct in identifying the advancement of the requirement for second 230 kV transmission line or equivalent for either VIC or JdF because of their lower transmission capacity as compared to VITR. CEC agrees with BCTC's assessment of approximately $12 million as an additional cost to either VIC or JdF for the value of this advancement (CEC Argument, para. 91-92, 163-164).

IRAHVOL associates the advancement of the second VITR circuit with the retirement of the HVDC system and proposes that the additional transmission capacity would provide back-up for VITR PST failure or other contingencies. IRAHVOL also states that the second circuit could require further advancement (earlier construction) if on-Island dependable generation is lower than planned (IRAHVOL Argument, pp. 49-50).

**Commission Determination**

Many factors may influence the advancement or delay of the second transmission capacity addition, but the requirement of that addition for either VIC or JdF will always be at least one year earlier than VITR because of the higher transmission capacity of VITR. **The Commission Panel determines that BCTC's assessment of at least $12 million as the cost that should be added to either VIC or JdF, to represent the one-year advancement from 2017 to 2016 of a second transmission capacity addition because of their lower transmission capacity as compared to VITR, is appropriate.**

### 7.8 Other Costs and Benefits of JdF

There were arguments made by Sea Breeze and BCTC regarding other costs and benefits unique to JdF. These revolved around the costs of ensuring a firm supply of power to Port Angeles, including the cost of possible upgrades on the BPA system, as well as other ancillary benefits of JdF such as increased trading capacity between the U.S. and Canada.

BCTC submits that the ability and cost of ensuring a firm supply of power at Port Angeles must be considered in any comparison of JdF and VITR (BCTC Argument, para. 69). During the proceeding, several conceptual ways were discussed for how service could be provided over JdF to Vancouver Island. In Argument, BCTC divides these into three proposals (BCTC Argument, para. 68):

1) Use JdF in a manner similar to VITR;

2) Contract for capacity on JdF on a relatively short-term basis while other means of meeting the needs of Vancouver Island continue to be explored; and

3) Contracting for service on JdF on a long-term basis but generally only using it in N-1 or N-1-1 situations.

According to BCTC, Proposal 1 would involve using JdF in a manner very similar to VITR so that JdF capacity would be available and could be used on a day-to-day basis and in a contingency to serve Vancouver Island. BCTC argues this would require having the necessary capacity available on the BPA system to Port Angeles and firm rights to this transmission capacity. For the scenario of wheeling power from the Lower Mainland to Port Angeles, BCTC points to a response of Sea Breeze under cross-examination that this "makes absolutely no business sense" for BCTC to use JdF in this way (T36:6936). Under BPA's Point-to-Point Tariff, BCTC estimated that the incremental cost of wheeling and losses on the BPA system would be CDN$10.2 million and $1.4 million per year, respectively. The PV (@ 6 percent) of the wheeling charges alone would be $153.5 million over 40 years, and this includes no allowance for future increases in BPA wheeling costs.

BCTC suggests that Proposal 2 (a short-term commitment to JdF) would provide BCTC and its ratepayers with the most flexibility. However, BCTC notes that Sea Breeze did not actively promote short-term contracts in its evidence or argument. BCTC suggests this may be because it would not assist in financing the project. BCTC also notes that even a short-term arrangement would still require upgrades to be in place on the Olympic Peninsula.

BCTC argues that Proposal 3 is analogous to Sea Breeze's "reliability alternative" (T36:6921-6922) and to Sea Breeze's proposal in response to BCUC 2.133.1 (Exhibit B2-17, BCUC 2.133.1). BCTC submits that while Sea Breeze agreed that the appropriate standard for Vancouver Island is the N-1 criterion based on NERC/WECC Planning Standards, it has ignored the requirement for firm contracted capacity on the BPA system to meet this standard. BCTC further submits that the only services available to provide firm transmission capacity are Point-to-Point (wheeling) service and Network Integration service. As noted previously, Point-to-Point charges would amount to CDN$10.2 million per year. Network Integration charges would be more than 20 percent higher than Point-to-Point charges. BCTC also submits that it could not rely on the existing Northwest Power Pool Reserve Sharing Procedures in the event of a transmission outage since BCTC can only call on these reserves in the event of generation contingencies (T37:7186-7187). BCTC argues this means that it would also need to contract for firm generation in the U.S. to meet reliability objectives.

Sea Breeze rejects the three scenarios proposed by BCTC as an inaccurate and overly simplistic reflection of the manner in which JdF should or would be used to serve Vancouver Island. Sea Breeze argues that the evidence indicates that "… a sufficiently secure supply of power can always be arranged at Port Angeles to allow JdF to be used to satisfy Vancouver Island's reliability needs…" (Sea Breeze Argument, para. 147). Sea Breeze suggests that the details of precisely how power would be delivered to the line in the most optimal way could be worked out in "open-minded, good-faith" discussions between Sea Breeze and BCTC. Sea Breeze described its position regarding the operation of JdF (Exhibit B2-17, BCUC 2.133.1). During the hearing, Sea Breeze also testified regarding the optimal operation of JdF for reliability purposes (T36:6921-6922).

Sea Breeze agrees that it would not make business sense to use the JdF to deliver B.C.-generated power to Vancouver Island on a daily basis and in an identical manner to how VITR would be used. Sea Breeze argues that in a contingency situation "… power would only actually be required to be carried to the Island via the JdF line, from a reliability perspective, during such months of the year when total Vancouver Island demand may exceed the approximately 2,000 MW of total dependable capacity available from the Cheekeye-Dunsmuir lines and on-Island generation…" (Sea Breeze Argument, para. 151). Once constructed, Sea Breeze suggests that the JdF, VITR or VIC could be operated in a way that would optimize on the existing conditions resulting from the different characteristics of each project. For VIC and VITR the optimization will be in relation to delivery of BC generated power, while for the Juan de Fuca the optimization would be in relation to the delivery location of imported power, possibly including the DSBs (Exhibit B2-17, BCUC 2.133.1).

Sea Breeze offers several alternatives to wheeling power from Blaine to Port Angeles, including return of the DSBs to Port Angeles, or diverting imports by Powerex to a delivery point at Port Angeles (Exhibit B2-17, BCUC 2.94.1). In all cases, Sea Breeze accepts that any additional wheeling costs arising from the use of JdF to meet contingencies "… should be taken into account in determining the price to be paid by BCTC for the purchase or lease of south to north capacity on JdF (in conjunction with the transmission service benefits on the BPA system that it is contemplated will be attributable to the JdF project…)" (Sea Breeze Argument, para. 157).

In Argument, Sea Breeze also suggests another option for obtaining firm power at Port Angeles, which it had not referenced in Exhibit B2-17, BCUC 2.94.1. Specifically, Sea Breeze suggests that:

> "…even if changes cannot be obtained to the Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024 to allow for the return of the DSBs directly to a Port Angeles point of delivery pursuant to the particular Agreement, arrangements may still be made for the disposal of all or a portion of the Canadian DSB entitlement in the United States pursuant to Article VIII of the Treaty and the Disposal Agreement referred to in recital F of Exhibit B1-131. Powerex could elect to receive a portion of the Canadian DSB entitlement directly at the point(s) of one or more of the US hydroelectric generation facilities on the Columbia River (which are the subject of the Treaty), which would provide a firm supply of power that could then be transmitted through the BPA system directly to Port Angeles (without going through Blaine)" (Sea Breeze Argument, para.158).

Sea Breeze goes on to note that "…the practical effect of such an arrangement would be to allow BCTC to rely on DSBs for the supply of power to Port Angeles without having to secure any changes to Exhibit B1-131; and, although this arrangement may be subject to wheeling costs to move power from the Columbia River to Port Angeles, it would avoid the need to wheel power from Blaine to Port Angeles and any other difficulties that might be associated with obtaining firm transmission along that path" (Sea Breeze Argument, para. 159). Sea Breeze suggests further that Powerex must already have reserved capacity on the BPA system in place for its trading activities and that Powerex could choose Port Angeles as a delivery point for its trading activities and would need to increase the capacity reservation to Port Angeles only if and when the amount of reserved capacity required to meet Vancouver Island's reliability needs exceeds the amount of capacity that Powerex would have reserved in any event for its trading activities. Even without factoring in the reservations that Sea Breeze suggests Powerex must already have in place for its trading activities, Sea Breeze concludes that the additional applicable wheeling charges for point-to-point service that would actually be needed to meet reliability requirements for Vancouver Island would be very substantially lower than the $10.2 million per year estimated by BCTC.

During the proceeding, there was also considerable discussion about what upgrades would be required to the BPA system to ensure that there is capability on the Olympic Peninsula to deliver 550 MW of power to Port Angeles, who would bear the cost of these upgrades, and if or when the upgrades would actually be made by BPA. Sea Breeze identifies two sets of upgrades on the BPA system (Exhibit B2-20, BCTC 1.26.7, pp. 53-54). The first set of upgrades, the Proposed Olympic Peninsula Reinforcements, are already being proposed by BPA for reinforcing the load service to the Olympic Peninsula, and are not driven by JdF. The second set of upgrades, the Level II Enhancements, eliminate the transmission constraints between Olympia and Port Angeles in order to be able to provide firm transmission capacity to JdF. During the proceeding, Sea Breeze expressed a willingness to pay for the initial costs of both sets of upgrades in order to gain the ability to provide a firm transmission path to JdF (T35:6789-6790; T36:7005). Sea Breeze stated the revenue stream to offset the upgrade costs would arise from the use of the JdF line and the credit for paying for those upgrades that Sea Breeze would obtain from BPA pursuant to BPA's OATT tariff (Sea Breeze Argument, para. 103).

Sea Breeze's willingness to pay for both sets of the initial BPA system upgrade costs, estimated to be US$75 to 80 million, was reiterated in Argument (Sea Breeze Argument, p. 46 and para. 136). Sea Breeze went on to say that the details of the arrangements to minimize wheeling charges should be addressed in open-minded and good faith discussions among the parties. Sea Breeze held to the principle that wheeling costs should be taken into account, in conjunction with applicable transmission service benefits on the BPA system, in determining the price to be paid by BCTC to purchase or lease south to north capacity on JdF, to ensure that B.C. ratepayers would still realize overall cost savings from use of the JdF line (Sea Breeze Argument, para. 164

and 169).

Sea Breeze indicates that it is confident that any required upgrades to the BPA system necessary to deliver required power to Vancouver Island by October 2008 will be completed assuming a contract results from this process (Sea Breeze Argument, para. 128). Sea Breeze argues that there is no evidence to support BCTC's contention that the required upgrades could include a 500 kV line upgrade on the Olympic Peninsula, which could in turn trigger a full NEPA/SEPA, creating further uncertainties regarding timing and cost.

Sea Breeze also suggests additional benefits from reliance on JdF that should be considered in the comparison with VITR (Sea Breeze Argument, para. 72). These include:

- Enhanced export capacity to U.S. markets;
- Enhanced arbitrage opportunities for BC Hydro and Powerex;
- Avoidance of health risks inherent in ac technology;
- Avoidance of public opposition and legal challenges;
- Avoidance of the seismic risks of VITR;
- Avoidance of the reliability of concerns caused by the VITR phase shifter;
- Enhanced Vancouver Island reliable capacity with minimal environmental impacts; and
- Bi-directional control and black-start capability.

Many of these suggested benefits are addressed elsewhere in this Decision. With respect to trade benefits (items 1 and 2 above), Sea Breeze notes that JdF would increase export capacity to the U.S. by 20 percent and suggests that BCTC would collect additional transmission revenues as a result. Sea Breeze also suggests that the JdF system would increase export potential by reducing congestion on the BC Hydro – BPA I-5 corridor, which restricts both imports and exports from and to BPA. Sea Breeze estimates annual benefits to BCTC, the BC Government and BC ratepayers from increased trade opportunities of $27.5 to 53.4 million annually, arising from a combination of increase OATT revenue from JdF customers, and revenue to Powerex from increased export and arbitrage opportunities via JdF (Exhibit C31-57, Undertaking T36:6871).

BC Hydro suggests that Sea Breeze is attempting to shift the onus from itself to other parties in connection with its attempt to demonstrate it has a viable alternative. BC Hydro submits that the onus belongs on Sea Breeze to provide probative evidence to support its proposal (BC Hydro Reply, para. 43). BC Hydro argues that there is no evidence that BC Hydro or Powerex would be making requests for a facilities study, as suggested as a possibility by Sea Breeze (BC Hydro Reply, para. 44). BC Hydro further submits that there is no ability in the Commission, nor evidenced willingness in BPA, to make open-minded, good faith negotiations occur regarding the form, timing or cost allocation of upgrades on the BPA system (BC Hydro Reply, para. 45). Finally BC Hydro suggests that none of the beneficiaries of the additional benefits purported by Sea Breeze for the JdF line have confirmed or corroborated those benefits (BC Hydro Reply, para. 46). In particular, BC Hydro notes that there is no evidence that Powerex is intending to or would be interested in electing Port Angeles as a delivery point for its trading activities. BC Hydro states that neither BC Hydro nor Powerex are forecasting any substantial trade benefits from increased transfer capabilities between Canada and the United States and that any estimate of these benefits is entirely speculative. However, BC Hydro also acknowledges that the project may have the potential in the long run to defer transmission projects that would otherwise be necessary to serve future needs, and that it is prepared to work with BCTC, BPA and Sea Breeze in the longer run to develop this potential.

BCTC stands by its initial assessment of the costs of JdF. BCTC argues that Sea Breeze did not provide any estimate of trade benefits prior to the undertaking requested by CEC and that if Sea Breeze truly believed these benefits were of the magnitude suggested, it should have put those numbers forward in the evidentiary phase of the proceeding (BCTC Reply, para. 190). Further, BCTC submits there is no evidence on the record of any third party interest in JdF that would give rise to the type and magnitude of benefits suggested by Sea Breeze (BCTC Reply, para. 192). With respect to BCTC's scenarios for ensuring a firm supply of power at Port Angeles, BCTC notes that its scenarios were taken from Sea Breeze's own evidence. Further, BCTC argues that the scenarios represent "book ends" within which any "optimal" solution must lie and that however it is used, appropriate arrangements must be in place on the BPA system

(BCTC Reply, para. 200). BCTC maintains that the proposal that it contract for capacity on an as-needed basis and supply Vancouver Island through the 500 kV lines would not satisfy NERC/WECC Planning Standards and would also increase system losses and require BCTC to address the Cut Plane D issue. BCTC further maintains that even if short-term firm service for a limited quantity of transmission capacity on the BPA system was available, this would still not provide any assurance that capacity would be available in the long-term and also ignores load growth on Vancouver Island and the need for sufficient lead time to plan alternatives (BCTC Reply, para. 203). With respect to the additional suggestion first raised in Argument that Powerex could elect to receive a portion of the DSB entitlement directly at one or more hydroelectric facilities in the U.S., BCTC notes it would still have to incur wheeling charges to deliver this energy to Port Angeles and it also maintains this option fails to address the economic ramifications of taking delivery of this energy as suggested (BCTC Reply, para. 204).

Other Intervenors provide general support for the concept of increased trade benefits from JdF (CEC Argument, para. 94-100; IRAHVOL Argument, pp. 65-66; TRAHVOL Argument, para. 2), although none produce any additional evidence regarding the likelihood or magnitude of such benefits to ratepayers. With respect to the issue of wheeling, the JIESC submits that nothing less than a firm wheeling contract is adequate to meet the needs of ratepayers on Vancouver Island (JIESC Argument, para. 98).

**Commission Determination**

The Commission Panel agrees that any incremental costs of firm wheeling and BPA system upgrades must be taken into account in any comparison of JdF and VITR. The Commission Panel must have assurance these costs will either be absorbed by Sea Breeze as part of the purchase or lease of South to North capacity or alternatively, that these costs are less than any guaranteed savings provided by Sea Breeze in relation to VITR.

The Commission Panel agrees with BCTC that the comparison of VITR and JdF should be on the basis of meeting NERC/WECC Planning Standards, which is the main reason VITR is required. The Commission Panel agrees with Sea Breeze this does not mean the project would necessarily be used to deliver energy on a continuous basis, although it may in fact be used in this way to optimize resources once built. However, the Commission Panel agrees with BCTC, BC Hydro and the JIESC that to satisfy N-1 planning criterion there must be a firm transmission path available to Port Angeles and BCTC must have long-term firm access to that path.

As a starting point for the analysis, the Commission Panel accepts BCTC's assessment that the cost of securing 550 MW of Point-to-Point service on the BPA system would be approximately $10.2 million per year based on BPA's current Point-to-Point tariff. The Commission Panel notes that the tariff is the same whether the path is to the B.C. border, Mid-C or some other point with firm generation available to BC Hydro. However, the total costs to ratepayers could be higher for some paths if there are additional upgrades required to the BPA system and those costs cannot be fully recovered in any tariff relief that may be provided by BPA to offset system upgrade costs. A Network Integration service would give BCTC and BC Hydro considerably more flexibility to optimize resources to meet contingency planning requirements for Vancouver Island, but as noted by BCTC, BPA's network service tariff would result in higher costs than a Point-to-Point service.

With respect to Sea Breeze's assertion that service could be contracted seasonally, the Commission Panel has no evidence that a firm transmission path can be secured on a long-term seasonal basis, or that doing so would result in substantially lower fixed wheeling costs than estimated by BCTC. The Commission Panel also notes that although BCTC may not require the full 550 MW of firm service to Port Angeles immediately, it would require the full wheeling capacity within a few years. The reduced wheeling capacity required in the first few years of the project would have little impact on the present value of wheeling charges over the 40 year project life. Further, the reduced cost would also need to be weighed against any additional risks associated with uncertainty introduced over the future availability and cost of additional wheeling capacity, when it is needed.

The Commission Panel does not have any evidence that current trading activities of BC Hydro and Powerex could be relied on to meet contingency planning requirements. Further, the arguments of Sea Breeze in this respect seem somewhat counterintuitive to the Commission Panel given that BC Hydro and Powerex do not currently rely on <u>firm</u> imports and there is no evidence they will do so over the long-term.

The Commission Panel notes that a generation hedge in the U.S. could be used as an alternative to a firm path from Port Angeles to B.C., but reliance on a generation hedge in the U.S. would still require Point-to-Point or Network Integration service on the BPA system. Further, the incremental costs of a generation hedge in the U.S. would also need to be compared to the reserve options available within B.C. to determine if such an option produced net savings to ratepayers in B.C.

The Commission Panel accepts that incremental wheeling costs to Port Angeles may be avoided if Port Angeles could be added as a delivery point for the DSB's. However, the Commission Panel finds no evidence that the DSBs, which are owned by the Province, would be available for such purposes, or that reliance on the DSBs for such a purposes would result in lower costs to ratepayers relative to other options that would be available to BC Hydro with VITR. Further, the Commission Panel agrees with BC Hydro and BCTC that negotiating a new delivery point for the DSBs would be a significant undertaking, adding to the possibility that JdF would not be able to meet the capacity shortfall on Vancouver Island in the same timeframe as VITR. Finally, even if the negotiations were successful, there is no guarantee that the negotiations would not result in some additional costs to ratepayers (e.g., for additional upgrades to the BPA system).

While agreeing that wheeling costs should be taken into account in the pricing arrangement for JdF, Sea Breeze also suggests these costs should be considered in conjunction with any applicable transmission service benefits on the BPA system. The Commission Panel notes that it is not the responsibility of BCTC to secure or pay for any benefits that may exist on the BPA system and this Commission has no authority to compel payment by BPA. It is the responsibility of Sea Breeze to secure compensation for these benefits, and the Commission Panel does not consider these to be relevant to the price paid by BCTC, although they may be important for the ultimate financial viability of JdF.

With respect to the trade benefits of JdF, the Commission Panel accepts that in theory there may be incremental benefits to the province from increased trading activity by third parties. However, the Commission Panel finds no compelling evidence on the record regarding the likelihood or magnitude of these benefits. The Commission Panel shares BC Hydro's concerns that the purported beneficiaries of these benefits have not confirmed or corroborated such benefits. Nor was this evidenced in the response to the Open Season conducted by Sea Breeze. Even if these benefits could be demonstrated, the Commission Panel does not necessarily view incremental trade benefits to the province as a relevant consideration in the comparison of VITR and JdF, unless those benefits accrue directly to ratepayers (in terms of third party wheeling revenue) or competing projects are otherwise comparable in terms of costs to ratepayers. The Commission Panel accepts BC Hydro's submission that neither it nor Powerex are forecasting any substantial trade benefits from increased transfer capabilities between Canada and the United States, and is not aware of any proposals by BC Hydro to increase the transfer capability of the BCTC system to the U.S. in order to facilitate additional arbitrage and trade. Neither does BC Hydro have a mandate or commitment for long-term firm exports beyond the optimization of existing hydroelectric storage capability.

While the Commission Panel agrees that incremental wheeling and generation costs should be taken into account in the comparison of VITR and JdF, the Commission Panel also notes that the transfer of construction and permitting risks to a third party could have some value to ratepayers in terms of cost certainty. However, in this instance the Commission Panel finds no evidence that such benefits exist in relation to contracting for service on JdF relative to proceeding with VITR.

In summary, the Commission Panel agrees with BC Hydro, BCTC and the JIESC that firm wheeling on the BPA system would be required to meet the reliability planning requirements of Vancouver Island. The Commission Panel uses the $10.2 million per year calculated by BCTC as a reasonable scenario for these costs. The Commission Panel does not include any additional allowance for BPA losses, which the Commission Panel agrees with Sea Breeze would be minimal for contingency planning purposes. The Commission Panel accepts there is some uncertainty over the long-term costs of firm wheeling on the BPA system. However, the Commission Panel finds no evidence that firm wheeling costs will be significantly below the $10.2 million estimated by BCTC. The only scenarios that could conceivably reduce firm wheeling requirements or costs would be excess generation in Port Angeles (for which there is no evidence) or a change in the delivery point for the DSBs. Even if it were possible to alter the delivery point for the DSBs, there could still be upgrade costs incurred by ratepayers. It is also unlikely that such negotiations could be successfully completed in the timeframe required to meet the reliability needs of Vancouver Island. Finally, the Commission Panel notes that the firm wheeling costs (or upgrade costs) would need to be reduced to below $2 million per year to make the ratepayer impacts of JdF equal to VITR, and even then there are still other considerations that would need to be factored into the comparison (e.g., different schedule risks).

### 7.9 Summary Project Comparisons

The table below summarizes the PV of direct and indirect costs for each project alternative based on the Commission Panel's determinations above. The VITR costs reflect Option 1 through South Delta and the Commission Panel's determinations with respect to the cable tenders. The project definition costs for VITR are excluded from the comparison, based on the Commission Panel determination that these costs are sunk. However, VITR project definition costs are included in the price of JdF as these were part of the pricing proposals prepared by Sea Breeze.

System benefits for VIC are reflected as costs against VITR in this analysis, as this captures the relative rate impacts of the two projects. For example, the synchronous condensers on Vancouver Island avoided by VIC are shown as a cost against VITR. These costs would also be avoided with JdF but seventy-five percent of the cost would still be payable to JdF under the pricing formula proposed by Sea Breeze. There are some other costs that would be associated with JdF but are not part of the pricing formula for JdF. For example, the Commission Panel has determined that system losses will be higher with JdF and these should be included in any comparison of VITR and JdF. Other costs to ratepayers not included in the pricing formula for JdF include the advancement of Phase 2 capacity, U.S. Wheeling Costs ($10.2 million per year) to provide a firm path to Port Angeles, and Lower Mainland VAr compensation. The latter has been included in the analysis because this cost would be avoided with VIC but would still be incurred with VITR or JdF.

The rate impacts in the table are estimated using the annualized revenue requirement approach used by BCTC (Exhibit B1-61, BCUC 4.206.0; Exhibit B1-1, p. 111, Table 4-7; Exhibit B1-6, BCUC 1.58.1), which is based on BC Hydro's weighted average cost of capital from the last Revenue Requirement Decision. As discussed in Section 7.10 below, assumptions about the cost of capital for BC Hydro or BCTC do not affect the relative project comparisons or conclusions of the Commission Panel.

As shown in this summary, VIC would have higher capital costs and O&M costs. The VIC alternative would avoid the additional costs of synchronous condensers on Vancouver Island, but would increase system losses by $36 million on a present value basis. The PV of total direct and indirect costs for VIC is $149 million higher than VITR. The Commission Panel considers this analysis conservative in that it finds considerably more uncertainty in the cost estimates for VIC.

JdF would have lower direct costs for ratepayers under the pricing formula proposed by JdF ($174 million for JdF versus $249.5 million for VITR). However, the indirect costs for JdF are substantially higher, including higher system losses, the advancement of Phase 2 capacity, and the additional cost of firm wheeling within the U.S. to meet an N-1 reliability planning criterion. This analysis does not consider BPA system benefits, as these would accrue to Sea Breeze and not BC Hydro ratepayers. No incremental third party revenues are included in this analysis as there is no compelling evidence regarding the likelihood or magnitude of additional third party revenues to BC Hydro ratepayers as a result of the addition of JdF.

The Commission Panel considers this analysis conservative in that it has used current BPA firm wheeling rates for the entire life of the project and has not included any allowance for incremental losses in the U.S. While it may be possible to reduce wheeling costs in the U.S., they would need to be reduced to less than $2 million per year before JdF would produce net savings for ratepayers.

As noted above, the Commission Panel also considers the schedule risks are higher for VIC and JdF, and places considerable weight on schedule risk in light of determinations regarding the need for capacity to Vancouver Island. As discussed in Section 8 below, there is also considerable uncertainty relating to the financing of JdF in light of the Commission determinations in this Section regarding the benchmark costs of VITR and the minimum payment required by Sea Breeze.

Based on the analysis and determinations in this Section, the Commission Panel concludes that VITR, as modified by the Commission Panel, represents the most cost-effective and certain project for meeting the capacity shortfall on Vancouver Island.

This conclusion in no way is intended to suggest that JdF may not be a viable or worthwhile project for addressing the needs of IPPs or other customers in B.C. It merely concludes the project is not a viable alternative at this time to VITR, which is required for contingency planning purposes. The Commission Panel makes no determinations at this time regarding the cost-effectiveness of Phase 2 of VITR. JdF may be a viable alternative to a Phase 2 project if Sea Breeze can secure sufficient third party revenues and address other project issues to offer ratepayers adequate certainty and an attractive price.

### Table 7-6: Summary Comparison of Project Alternatives

**Summary Cost and Rate Impact Comparisons**

**P50 Estimate - includes contingencies, OH, IDC (millions $2005)**

**Discount Rate 6%**

| | VITR | VIC | JdF |
|---|---|---|---|
| **Direct Ratepayer Costs** | | | |
| Phase 1 - Project Definition | $ - | $ 24.5 | $ 9.0 * |
| Phase 2 - Project Implementation | $ 208.0 | $ 311.0 | $ 156.0 * |
| Contingency | $ 12.0 | $ 10.5 | $ 9.0 * |
| Phase 1 & 2 Total | $ 220.0 | $ 346.0 | $ 174.0 * |
| PV of Direct O&M | $ 2.5 | $ 13.5 | $ - |
| PV of Taxes | $ 27.5 | $ 27.5 | $ - |
| Total Direct Costs (Phase 1& 2 Plus O&M) | $ 249.5 | $ 386.5 | $ 174.0 * |
| | | | |
| **Indirect Ratepayer Costs** | | | |
| Seismic Strengthening of ARN | $ - | $ - | $ - |
| Synchronous Condensers on VI | $ 5.5 | $ - | $ 4.0 * |
| PV of O&M for Pole 1 & 2 | $ - | $ - | $ - |
| South of Cut Plane D Upgrades | $ - | $ - | $ - |
| PV of Losses (compared to VITR) | $ - | $ 36.0 | $ 37.5 |
| Advancement of Phase 2 Capacity | $ - | $ 12.0 | $ 12.0 |
| US Wheeling Costs and Losses | $ - | $ - | $ 153.5 |
| LM VAR Compensation | $ 30.0 | $ - | $ 30.0 |
| Total Indirect Ratepayer Costs | $ 35.5 | $ 48.0 | $ 237.5 |
| | | | |
| **Total Direct and Indirect Costs** | $ 285.5 | $ 434.5 | $ 411.5 |
| Cost Increase (Savings) Relative to VITR | $ - | $ 149.5 | $ 126.0 |
| | | | |
| **Rate Impacts** | | | |
| Annualized Direct Costs | | | |
| % of F2006 Transmission RR | 4.9% | 7.6% | 3.4% |
| % of F2006 BCH RR | 1.1% | 1.7% | 0.7% |
| Annualized direct and indirect costs | | | |
| % of F2006 Transmission RR | 5.6% | 8.5% | 8.1% |
| % of F2006 BCH RR | 1.2% | 1.9% | 1.8% |

* Denotes a cost included in the pricing formula to Sea Breeze for JdF.

## 7.10 Cost of Capital

The Revised Hearing Issues List (Exhibit A-71) included several questions related to the cost of capital and its relevance for comparing competing projects in this proceeding. Specifically, the Commission Panel sought answers to the following questions:

- How does the Juan de Fuca proposal affect the project comparison?
- What is the effect that incremental capital investments undertaken by BC Hydro have on BC Hydro's cost of service and therefore its rates?
- How is this relevant to project selection decisions?

- How is this relevant to financing and ownership decisions?

Similarly, Item 4.3 "Cost of Service and rate impacts for each project option" and Item 7.3 "Cost of Service and rate impacts of the project" for VITR and for the Revised VIC Proposal respectively invite evidence and argument on the cost of capital for VITR and other project alternatives.

At the conclusion of the oral evidentiary phase of this proceeding the Chair provided some suggestions to legal counsel with respect to matters to deal with in argument. One of the questions asked by the Chair was: "Given the evidence and matters to be decided in this proceeding, should this Commission Panel review the cost of service analysis of capital projects conclusions found at page 35 of the VIGP Decision dated [September] 8, 2003 (T40:7543)?" In the VIGP Decision the Commission rejected the 100 percent debt-financing, proposed by BC Hydro, as impractical for the cost of service analysis, considering BC Hydro's expectations of system renewals. The Commission agreed with Intervenors that major capital projects should be considered to be financed at the Utility's weighted average cost of capital.

In Argument, BCTC submits that the matters considered by the Commission at Section 5.5 of the VIGP Decision are relevant, substantially similar to the issue discussed in this proceeding and should be considered by the Commission Panel (BCTC Argument, para. 51). BCTC rationale for this position is outlined below.

> "BCTC calculated the transmission rate impacts of VITR and VIC using a 71.6% debt/28.4% equity capital structure, which was the capital structure last used to set BC Hydro rates for F2006. This is also the capital structure calculated consistent with the requirements of Special Direction HC2 during the last BC Hydro rate case" (BCTC Argument, para. 43).

While acknowledging that on an incremental basis BC Hydro may fund VITR with debt and while not taking issue with the pre-filed evidence of Mr. Morris (Exhibit C6-14) as it relates to the application of Special Directions HC1 and HC2, BCTC reinforces the importance of the Commission's focus on the following two questions (BCTC Argument, para. 44-46):

1. How should long-term rate impacts of BC Hydro investments be assessed; and
2. When comparing the rate impacts of competing private sector and BC Hydro projects, what capital structure should be used?

By referring to the cross-examination of Mr. Morris in Transcript volume 35, BCTC lists the facts it considers relevant for the issue (BCTC Argument, para 46):

- Except for when BC Hydro's debt exceeds 80 percent of the capital structure, 15 percent of its distributable surplus is kept as retained earnings. BC Hydro's debt level is not forecast to exceed 80 percent at the time frame VITR is to be funded.
- In any particular year, BC Hydro funds its capital investments through free cash flow or issuing new debt.
- BC Hydro has experienced years of significant capital investment during which no additional debt was issued. As a result capital investments were completely funded through free cash flow.
- For the years F2001 through F2005 the net book value of capital assets consistently exceeds net long-term debt by between \$2.6 to \$3.3 billion.
- BC Hydro does not project finance each capital investment it makes.
- Financing needs are determined in aggregate and free cash flow is managed in aggregate to arrive at the appropriate amount of debt to issue in any given year.

In conclusion, BCTC submits that it is BC Hydro's equity, regardless how equity is defined, together with debt that finances BC Hydro's long-term assets. While the Special Directions create a unique definition of equity to be used in rate making, the circumstances of BC Hydro are in other respects similar to private, investor-owned companies where the long-term financing of new investments are concerned. The theory of corporate finance is that long-term assets are funded by the weighted average of long-term debt and equity and BC Hydro is no different in that respect (BCTC Argument, p. 20, para. 47-48).

In Reply, BC Hydro not only rejects BCTC's analysis but, more importantly, submits that this proceeding is neither the time nor place to consider the challenging topics raised by BCTC in its argument. Rather, in this proceeding, the Commission should limit its review of Mr. Morris's evidence to the issues it was intended to address (BC Hydro Argument, para. 31).

BC Hydro submits that Mr. Morris's cogent explanation of the formulas contained in the Special Directions leave no room for argument with respect to what the rate impact will be. BC Hydro argues that the construction of VITR under BCTC's direction and at BC Hydro's expense will increase the debt of BC Hydro by an amount equal to the capital cost of the project and will have no impact on the amount upon which BC Hydro is entitled to earn a return on equity, except in those years when BC Hydro's debt/equity ratio can be kept at or below 80/20 only by reducing its dividend payment to the Province (BC Hydro Argument, para. 26).

Sea Breeze concurs with the position taken by BCTC by stating that the issues raised in the VIGP decision are no different than the issues at play in this proceeding and that there is no evidence suggesting that conclusions reached in the VIGP Decision should not be followed in this case (Sea Breeze Argument, para. 385-388).

Sea Breeze further emphasizes its view by quoting its expert witness, Mr. Moscardelli of EIF, as follows:

> "In our opinion, the rate impact arising from a utility's investment in additional long-term capital assets should be analyzed based on the weighted average cost of capital of the utility. This is because the utility's assets will be supported by the equity in the utility over the course of the life of the assets. The financing of a utility's long-term assets at 100 percent debt is not a sustainable scenario. It would also mean that each one of the utility's current assets has a different cost of capital, which is irrational and illogical. In the financing of long-term assets of a utility, capital dollars should not be traced to specific projects, but rather to the utility's entire asset base" (Sea Breeze Argument, para. 389).

The CEC also agrees with BCTC's summary of the evidence with respect to the question of the appropriate capital structure and cost of capital to be used when evaluating projects and when determining rate impacts. The CEC further submits that the VIGP Decision provides useful guidance consistent with the views of BCTC. However, CEC believes the VIGP Decision guidance is incomplete and argues that it would be advisable to revisit it with a view of optimizing value for rate payers in cases where private sector projects are involved and ensuring the playing field is level with respect to cost of financing (CEC Argument, para. 45-48).

IRAHVOL also agrees with positions adopted by BCTC, Sea Breeze and CEC. By referring to the cross-examination of Mr. Morris, IRAHVOL submits that while BC Hydro must fund new investment through cash flow or debt it does not use cash flow exclusively to pay down debt. Further, IRAHVOL argues that the opportunity cost of internally generated cash flow is not the same as the cost of debt and points out that BC Hydro always has the option of refunding cash to its customers which introduces another reference point for determining the opportunity cost of BC Hydro's cash flow (IRAHVOL Argument, p. 83).

During the Oral Argument Phase, the Commission Panel again raised the issue whether given the evidence and matters to be decided in this proceeding, it should review the findings of the Commission in the VIGP Decision regarding cost of service analysis of capital projects. Specifically, the Commission Panel sought confirmation of BC Hydro's position (BC Hydro Argument, para. 25-32) and clarification how, should it accept BC Hydro's argument, it should deal with JdF pricing with reference specifically to Exhibit B2-64, BCUC 4.155.1, pp. 5-6; Exhibit C31-15, pp.2-3; Exhibit C31-57, Undertaking; and T36:6857-6858, 7037, 7091-7093. Finally, the Commission Panel wanted to clarify Sea Breeze's position based on its paragraph 25 of its Reply.

Counsel for BC Hydro reiterates BC Hydro's position with respect to these issues at T42:7815-7830. First, counsel for BC Hydro notes that BC Hydro intends to file broad evidence regarding the cost of capital issue as part of the BC Hydro's IEP/LTAP proceeding, which he suggests is a better forum for dealing with the appropriateness of BC Hydro's policies in this regard. Second, counsel for BC Hydro argues that the cost of capital issue is not relevant to these proceedings. Specifically, counsel for BC Hydro submits that none of the parties going into the proceeding understood how Sea Breeze thought it should be remunerated for any of its projects. Counsel for BC Hydro also submits that it was only on March 29, 2006 when Sea Breeze provided Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093 that it provided any clarity regarding compensation for JdF. Based on Exhibit C31-57, Counsel for BC Hydro argues that Sea Breeze is seeking a minimum payment to make its project proceed and that the minimum payment does not revolve around the cost of VITR. Counsel for BC Hydro did note that whether that payment ultimately turns out to the benefit of BC Hydro customers does depend on the foregone cost of VITR, but he submitted that the revenue stream required by Sea Breeze does not require a determination of the cost of capital for VITR.

In response to a question from the Chair, Counsel for BC Hydro indicates the evidence of Mr. Morris was intended to be factual and not to establish a general policy. He submits that the Commission is not constrained to using 100 percent debt for the purposes of comparing the costs of VITR and JdF. However, he argues a determination regarding the capital structure is not required based on the Sea Breeze submission in Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093. Finally, Counsel for BC Hydro suggests that should the Commission Panel see the issue differently, that it limits its determination to this proceeding and not attempt to establish a general policy with respect to the cost of capital to be used in comparing BC Hydro/ BCTC projects with competing private sector alternatives.

In response, Counsel for Sea Breeze argues that the issue was squarely on the table during the proceeding. Specifically, Counsel for Sea Breeze refers the Commission Panel to Exhibit B2-64 in which Sea Breeze proposed a payment for JdF based on 75 percent of the annual cost of service for VITR. Counsel for Sea Breeze argues that BC Hydro came forward with the evidence of Mr. Morris well after that evidence was filed. Counsel for Sea Breeze questions BC Hydro's reliance on Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093, which he characterized as "…nothing more than a progression based on questions that were asked of various parties, based on different assumptions as to what might be satisfactory in the circumstances" (T42:7835). Specifically, he refers the Commission Panel to Exhibit C31-15 which was filed as an undertaking requested by Commission Counsel. In that undertaking, Sea Breeze indicated it has revised its response to BCUC 4.155.1 in light of the evidence subsequently filed by BC Hydro regarding financing VITR with 100 percent debt. In that undertaking it revised its position indicating that the proposed pricing formula would not be appropriate in the event of 100 percent debt financing assumption. However, Sea Breeze also referred to other alternatives for payment, including a lump sum payment, which would not be directly driven by the debt-equity assumption for VITR.

**Commission Determination**

As noted above, the Commission Panel relied on the lump sum payment formula proposed by Sea Breeze as the basis for comparing the project alternatives. That payment formula does not require any assumption about the cost of capital for VITR and it was adequate for the Commission Panel to establish that VITR is in the public interest. Although the cost of capital is an important consideration in some of the pricing formulas proposed by Sea Breeze and the ability of Sea Breeze to secure financing, the Commission Panel's overall conclusion regarding JdF or VIC does not in fact hinge on the cost of capital for VITR. The Commission Panel therefore makes no formal determination regarding an appropriate cost of capital for project selection.

However, the Commission Panel is troubled by the evidence and arguments made by BC Hydro on this issue during these proceedings. The Commission Panel rejects BC Hydro's submission that the cost of capital was not a relevant issue during the proceeding or that it could anticipate this issue would not be relevant to the decision of the Commission Panel. While the final decision of the Commission Panel does not hinge on this issue, it arrived at this conclusion for different reasons from BC Hydro and this conclusion was neither obvious nor inevitable at the outset of this proceeding. BC Hydro had considerable notice regarding the possible importance of this issue to the Decision in the form of the Revised Hearing Issues List (Exhibit A-71), the questions posed to BCTC and Sea Breeze by Commission staff and Intervenors, and the evidence filed by Sea Breeze in Exhibit B2-64, BCUC 4.155.1. BC Hydro raised concerns about the lack of clarity regarding the intentions of Sea Breeze in these proceedings. The Commission Panel has similar concerns with respect to BC Hydro's evidence concerning the cost of capital. The Commission Panel notes in particular the different arguments by BC Hydro during the hearing concerning the filing of Mr. Morris' evidence (T24:4435-4439) and during the Oral Phase of Argument (T42:7815-7820).

The Commission Panel is concerned by the apparent lack of a pre-existing policy on this issue within BC Hydro, particularly in light of the VIGP Decision, current government policy with respect to the role of the private sector in power development, and the statements by BC Hydro and BCTC regarding their receptivity to merchant transmission in the province. The Commission Panel concurs with Intervenors in this proceeding that the cost of capital issue may be very relevant to private sector developers of possible alternatives to BC Hydro or BCTC sponsored projects, and some certainty with respect to this issue is required in light of the significant investment required to identify, define and promote opportunities that may be of benefit to ratepayers. The Commission Panel supports BC Hydro's intention to file broad policy evidence on this matter in the IEP/LTAP proceeding.

## 8.0 OTHER RELEVANT PROJECT SELECTION CONSIDERATIONS

Throughout the proceeding Sea Breeze argued that it had not been treated fairly by BCTC, suggesting a bias of BC Hydro and BCTC against merchant transmission in general and Sea Breeze in particular. There were also several general issues raised with respect to the role of merchant transmission in B.C. and the appropriate basis for comparing merchant transmission and utility-funded transmission projects, including the treatment of differences in cost of capital and taxes, as well as the treatment of other ancillary benefits from merchant projects. There was also considerable debate regarding the degree of control the Commission has over merchant transmission and the standard of certainty it should apply to a merchant proposal such as JdF in order to consider it a viable alternative to a utility-funded project such as VITR. Section 8.1 will deal with BCTC’s responsiveness to Sea Breeze and more general issues raised with respect to the comparison of merchant transmission and utility-funded projects. Section 8.2 will consider issues regarding the certainty of JdF proceeding, and in particular the financing for the project.

### 8.1 The Role of Merchant Transmission in B.C. and BCTC’s Responsiveness to Sea Breeze

Sea Breeze suggests that “…BCTC made no efforts to truly consider whether JdF could be used to meet the needs of Vancouver Island better than VITR” (Sea Breeze Argument, para. 56). BCTC submits this is not the case and that an objective review was done and simply concluded that JdF was not the right project. BCTC also rejects Sea Breeze’s suggestion that since BCTC has been aware of JdF since March 2004, it should have been aware of Sea Breeze’s ambitions for JdF to be a substitute for VITR. BCTC argues that JdF was submitted as a merchant proposal and that Sea Breeze maintained this position in its discussions with BCTC until shortly before the hearing. BCTC further notes that all of the studies that Sea Breeze requested for JdF were in combination with VITR, and the DLA dated April 6, 2005 contains no mention of an agreement between Sea Breeze and BCTC for south to north capacity on JdF to serve Vancouver Island or an agreement with BCTC for system benefits (BCTC Reply, para. 180-182).

BCTC also rejects Sea Breeze's assertions that it opposes merchant transmission projects and that it attempted to thwart Sea Breeze's initiatives. BCTC states that it was not always able to fully understand Sea Breeze's current ideas and acknowledges that turnover of the executive level of BCTC may have contributed to its inability to fully understand the proposals. Nevertheless, BCTC met with Sea Breeze on many occasions and conducted studies for Sea Breeze whenever it was requested to do so. BCTC provides a chronology of its interactions with Sea Breeze as Appendix C of its Argument. However, since JdF was first raised, BCTC has had fundamental concerns about Sea Breeze's ability to finance the project and when, if ever, it might be built (BCTC Argument, para. 57-60).

BCTC defined merchant projects as projects "…developed by privately owned companies that obtain private funding based on the sale of the project's output (transmission rights in the Sea Breeze Juan de Fuca case) at market-based rates, and without recourse to cost of service regulated rates" (Exhibit B1-6, BCUC 1.21.6). BCTC further suggested that "…[p]rojects seeking access to cost of service regulated rates are generally not merchant projects." BCTC indicated it is not opposed to merchant transmission in B.C. but that it has not as yet had to consider the use of merchant transmission in its mandate. BCTC indicated that merchant transmission could co-exist with a regulated transmission system operated in the public interest. BCTC noted:

> "BCTC would consider merchant transmission in its long term capital planning provided sufficient evidence materialized to suggest that a merchant transmission project was going to proceed. Since BCTC may not be aware of what third party developers may be considering at any point in time, or the likelihood of those developers' proposals moving forward, BCTC prepares its long-term transmission capital plan without consideration of unconfirmed third party projects. BCTC has taken the approach that, if a company is interested in pursuing a merchant transmission line that they wished to have considered as part of BCTC's long-term transmission capital plan, those third parties should come forward to request and pay for the necessary studies to assess their projects' implications for interconnection and impact on the BCTC managed transmission system, as would any other customer wanting to interconnect to the system. BCTC does not speculate on what impacts unconfirmed merchant projects might have. Should a merchant transmission project developer move forward with the necessary studies BCTC would consider such potential projects in its long-term capital planning" (Exhibit B1-6, BCUC 1.21.6).

With respect to whether BCTC had considered JdF as an alternative to VITR, BCTC indicated:

> "BCTC did not consider a reinforcement option similar to the Juan de Fuca project when considering alternatives to supply Vancouver Island because, under BCTC's tariff, it is the NITS customer's (BC Hydro's) responsibility to designate network supply resources, whether inside or outside BC , to meet their network load requirements. BCTC has not received any indication from BC Hydro to date that it intends to serve its network load customers on Vancouver Island from resources in the US , other than the Downstream Benefits, or from wheel throughs from BC to the US and back to Vancouver Island" (Exhibit B1-6, BCUC 1.21.1).

BC Hydro submits that the responsibility for ensuring transmission is adequate resides with BCTC, and submits that there is no basis for the Commission to encourage BC Hydro to negotiate to purchase transmission service on JdF or to require BC Hydro to purchase power from any specific source (BC Hydro Argument, para. 53).

During the proceeding, there were also a variety of issues raised regarding the basis of comparison for merchant and ratepayer-funded projects, including issues such as capital structure, taxes and ancillary benefits such as trade opportunities. The Commission Panel has discussed the issues of capital structure and trade opportunities elsewhere in this Decision. IRAHVOL raised the treatment of taxes paid by private proponents of competing projects during cross-examination of BCTC, and asked whether BCTC would take into account the provincial income taxes that these third-party private projects would generate. BCTC replied that it would consider the impact of the project on the ratepayer, rather than the impact on the provincial treasury (T10:1516-1520).

The issue of the tax treatment of private developers was not raised in Argument. However, in Reply, BC Hydro notes that a number of parties have suggested that the proper means of comparing BC Hydro utility transmission with merchant transmission needs to be determined in this proceeding. BC Hydro maintains many of those parties have suggested a precedent-setting discussion that would go well beyond comparing utility transmission with merchant transmission and cover future comparisons of all BC Hydro funded projects with privately funded projects. BC Hydro submits that such broad questions as that can only be answered in the context of appropriately broad evidence, which should arise in the context of the current IEP/LTAP proceeding (BC Hydro Reply, para. 50).

Sea Breeze appears to suggest that BCTC has not properly responded to directives from the Commission (Sea Breeze Argument, para. 32-33). The Commission, in its November 19, 2004 Decision on BCTC's 2005 Capital Plan Application, directed BCTC to respond to a question regarding the impact of the construction of a HVDC facility between Vancouver Island and the Olympic Peninsula on its transmission system, and whether the requirement for the 230 kV line proposed by BCTC could be deferred or eliminated (Exhibit B2-52, p. 12). BCTC responded on December 20, 2004 that Sea Breeze had not confirmed how the proposed connection to the BPA system on the Olympic Peninsula would be used. If the Sea Breeze line was built and was able to provide sufficient, dependable capacity, BCTC indicated that it might defer or eliminate the need for VITR. However, discussions with BPA staff indicated that the existing BPA transmission facilities in the area have limited capacity and the source of the power to be imported was uncertain (Exhibit B2-52, p. 17).

BCTC states that it takes the Commission's directives very seriously and does its best to comply with them (BCTC Argument, para. 61; T16:2721). It relies on its responses to the directive as evidence that it complied with those directives (BCTC Reply, para. 186). BCTC believes that if the Commission had intended its directive in the BCTC 2006 Capital Plan Decision to be a direction that BCTC should adjourn the VITR CPCN application, it would have expressly said so (BCTC Argument, para. 61; T16:2763).

**Commission Determination**

The Commission Panel does not agree with Sea Breeze that the evidence shows BCTC did not adequately consider the JdF proposal as an alternative to VITR. Further, the Commission Panel notes there has been adequate consideration of JdF during this proceeding. The Commission Panel also notes that Sea Breeze makes no suggestion that BCTC was less than fully responsive to any requests it made for interconnection or other studies in BCTC's role as transmission system operator. The Commission Panel does find that BCTC could have done a better job documenting its internal deliberations concerning the JdF proposal.

The above conclusion notwithstanding, the Commission Panel is concerned by the apparent gap in responsibility for considering merchant transmission proposals as an alternative way to address ratepayer needs. BCTC indicates it was BC Hydro's responsibility to identify external resources and/or transmission paths in its NITS application. However, the Commission Panel can see no requirement for BC Hydro to specify transmission routes, technologies or other arrangements as part of the NITS Application and the Commission Panel considers it BCTC's responsibility to identify and evaluate all reasonable alternatives to providing network services, including the possibility of utilizing third party projects, where applicable.

The Commission Panel is not persuaded by Sea Breeze's arguments that it is the responsibility of BCTC to identify and explore all of the ways in which a merchant transmission project could be used to meet ratepayer needs or that this should be done through the type of "open-minded, good faith discussions" suggested by Sea Breeze in Argument (para. 149). The Commission Panel agrees with BCTC that Sea Breeze was not particularly clear in its intentions with respect to the JdF prior to this proceeding and seemed to be forming its case well into the proceeding. The Commission Panel considers that Sea Breeze must accept responsibility for identifying viable options for using JdF as an alternative to VITR, including offering any additional services or arrangements that may be required to fulfill the needs of its potential customer, in this case the needs of BCTC, with respect to contingency planning for Vancouver Island. It was clear to the Commission Panel that Sea Breeze prior to the hearing had not fully considered all of the issues associated with using JdF to meet an N-1 planning criterion for Vancouver Island, and that there is still considerable uncertainty regarding the options for meeting the criterion. The Commission Panel acknowledges that a merchant provider may require information from BCTC or BC Hydro in order to develop its case. However, the Commission Panel notes there was considerable ability for Sea Breeze to gather that information in this proceeding and that prior to BCTC's Application Sea Breeze also had other remedies available to it under Sections 72 and 83 of *UCA* if it was not getting adequate information or cooperation from BCTC or BC Hydro to develop its project.

## 8.2 Commission Control over and Financing of JdF

In addition to its concerns that BCTC and BC Hydro did not seriously and fairly consider or evaluate the JdF alternative, Sea Breeze contends that BCTC, BC Hydro, the JIESC and other Intervenors have established an inappropriate standard of certainty that the JdF proposal will be built before BCTC or the Commission should even entertain JdF as an alternative to VITR. The debate centred on the Commission's control over the construction of JdF and its likely financing. This Section of the Decision reviews the issues raised by various parties regarding the control of the Commission over JdF in comparison with VITR, the likelihood Sea Breeze would be able to finance JdF and the certainty required before BCTC or the Commission seriously consider a merchant transmission alternative to a ratepayer-funded project.

### 8.2.1 Commission Control over JdF and VITR

BCTC submits that, given the Commission's absence of control over JdF (given that it crosses an international boundary and will therefore be regulated by the NEB), the Commission "…should be persuaded that there is a virtual certainty that JdF will proceed before it should be considered a legitimate alternative to VITR" (BCTC Argument, para. 62). BCTC relies on the Commission's broad statutory powers over the utilities under its jurisdiction and references Sections 23, 42, 96, 97 and 98 of the *UCA* which, among other things, provide a duty for a public utility to obey orders; the ability for the Commission to authorize substitutes to carry out orders; and powers of entry, seizure and management to enforce an order (BCTC Argument, para. 63). BCTC submits that "… when the Commission issues a CPCN for the construction and operation of facilities that are necessary for the provision of safe and reliable utility service, the Commission has virtually unfettered powers over the utility itself, and if efforts directed at the utility are unsuccessful, to directly intervene in its own capacity, to ensure that the needed facilities are put in place. The collorary [sic] of this is that the Commission knows, when it grants such a CPCN, that there is a virtual certainty that the project will be undertaken, or the Commission can cause it to be undertaken" (BCTC Argument, para. 64).

Since the Commission does not have jurisdiction over Sea Breeze or JdF, BCTC submits that the Commission needs to be persuaded that facilities, the construction of which is beyond its control, "…will, or there is a virtual certainty that they will, be completed and operated in the manner contemplated." BCTC submits there is no such virtual certainty that either the upgrades required for JdF or the project itself will take place (BCTC Argument, para. 65-66).

BC Hydro, BCOAPO and the JIESC all support the Commission applying a "virtual certainty" test to JdF (BC Hydro Argument, para. 8; BCOAPO Argument, pp. 6-7; JIESC Argument, para. 93-97). For example, the JIESC submits that "…the Commission must be "virtually certain" that the JdF Project will proceed on an acceptable schedule before the project is even considered as a possible alternative to VITR. The consequences of not securing reliable and timely transmission reinforcement to Vancouver Island are simply too great to take any other position" (JIESC Argument, para. 93). The JIESC submits that the Commission has significant power to ensure BCTC and BC Hydro carry out their obligations under a CPCN, which it would not have in the case of Sea Breeze, and that Sea Breeze and its partners, including EIF, have not adequately demonstrated that JdF, or the necessary upgrades to the Olympic Peninsula, will be completed in a timely manner. BC Hydro and BCTC make similar arguments.

Sea Breeze addresses the issue of the "virtual certainty" test in its Argument and argues that there is no basis for the test in either the *UCA* or in the jurisprudence based on the ***UCA.*** Sea Breeze submits the test was only developed by BCTC in response to opening oral submissions from BC Hydro and appears to be evolving and becoming more onerous as time passes (Sea Breeze Argument, para. 74-75).

Sea Breeze disagrees with the suggestion that the sections of the *UCA* referred to by BCTC will create certainty that VITR will be constructed and says Sections 45 and 46 of the *UCA* do not require construction, but rather simply permit construction. Sea Breeze provides as an example BC Hydro's abandonment of the generation facility at Duke Point (Sea Breeze Argument, para.77).

Sea Breeze submits that it is inappropriate and illogical to hold JdF to a higher standard than that required by VITR. It further submits that even that level of certainty with respect to JdF may not be necessary, depending on the order granted by the Commission. It argues that "…[t]he degree of certainty required should be proportionate to the risk inherent in the nature of the order…." and that "…the essential question for the Commission should be whether there is sufficient merit to Sea Breeze's position that JdF is reasonably capable of satisfying Vancouver Island's reliability needs such that it would be in the public interest to direct parties to enter into good faith negotiations with respect to JdF before approving a CPCN for either VITR or a VIC-like project" (Sea Breeze Argument, para. 84). Sea Breeze concludes that the level of certainty required of JdF should depend on the order of the Commission, but in no event should the level be higher than that required for VITR (Sea Breeze Argument, para. 85).

BCTC submits that it is not proposing a different standard for JdF than VITR and that, based on the record of this proceeding, the Order sought by BCTC, and the Commission's ongoing powers under the *UCA* over public utilities subject to its jurisdiction, the Commission can be virtually certain that VITR will be built. BCTC adopts the submissions in BC Hydro's Reply that Sea Breeze's submissions on this issue appear to rest on a misunderstanding of the Commission's powers under the *UCA (*BCTC Reply, para. 194).

BC Hydro takes issue with the Sea Breeze suggestion that the Commission cannot require construction of VITR. BC Hydro points to Sections 35, 38 and 42 of the *UCA* and says they provide the necessary statutory authority to the Commission. These include powers for the Commission to compel a utility to extend service, provide service, and obey orders (BC Hydro Reply, para.10-14).

BC Hydro also submits that any analogy to the Duke Point Project is "completely inappropriate" since the project was not a regulated project. It involved the Commission's acceptance of an energy supply contract for filing under Part 5 of the *UCA*. In BC Hydro's submission "…energy supply contracts are subject to fundamentally different regulatory oversight than public utility projects and no comparison between the two can properly be made" (BC Hydro Reply, para. 20-23).

In the Oral Phase of Argument, Counsel for BCTC clarifies BCTC's position as follows:

> "When we raised the virtual certainty test in the pre-hearing conference and then that concept has been brought forward in argument, we were not suggesting in any way that there is jurisprudence that supports that test… We raised it primarily as what we considered to be the appropriate factual test that the Commission should apply, and then expanded on that in our arguments, to why, given the Commission's authority under the Act [*UCA*], that we considered that to be appropriate… [I]f it appears that a project for which you have granted a CPCN, a project for which a utility is responsible, is not pursuing that project with reasonable diligence, you have a broad scope of powers under the Act [*UCA*] to effectively -- and again, this is linking back to an earlier discussion -- to enforce those actions up to the most significant power to actually in those circumstances step into the shoes of management. Not that I'm aware of that ever having been done. You simply don't have that power with respect to a project which is beyond your jurisdiction, and accordingly can't be proactive after the fact if you found that to be necessary" (T42:7765-7767).

In an exchange with the Chair, Counsel for BCTC agrees that the proposed test is not unique to a merchant facility. Rather, it is dependent on the context and options before the Commission in a particular situation. That is, it is dependent upon the need for the project (which helps to define the weight that may be given to certainty) and the relative certainty among the available alternatives before the Commission. Counsel for BCTC also notes "…there has to be some weighing of the different attributes of alternative projects in your [the Commission's] determination. And it could be that you have a situation where there is a project that you think offers other benefits but may well be somewhat less certain, but in the context of the evidence in the process, you say, well, we're prepared to take a risk, knowing what the conditions are with respect to the risks associated with delay on that other project, as compared to the first one" (T42:7770).

Counsel for BC Hydro adopts the submissions of Counsel for BCTC regarding the relative test of certainty. He notes that while there may still be some uncertainty around timing, there is no uncertainty regarding the ability of the Commission to compel BCTC to construct VITR or about the ability of BCTC to accomplish the task. He submits that it is this fact, together with the

Commission's previous findings regarding the need and timing for a solution to Vancouver Island's capacity shortfall that establishes the bar for JdF in this proceeding. He also notes that while Sea Breeze has applied to the NEB for a CPCN (based on the trans-boundary nature of the project), the granting of a CPCN by the NEB in no way ensures the project will be built. The decision to build JdF rests entirely with private investors. He goes further to suggest that it is the reliance on financing from others that is an important fact in this case. Specifically, he suggests that "…where an applicant comes forward to meet a utility need, it needs to have utility financial integrity" (T42:7776).

The Chair asked BCTC whether there would be anything lost if there was a condition on an Order approving VITR that BCTC negotiate with Sea Breeze in order to see if some of the uncertainties over the pricing and financing of JdF could be resolved. In responding, Counsel for BCTC highlights several issues. First, he notes the cable tenders are only valid for 120 days and commodity prices remain a risk for BCTC until a contract is signed. Further, the available time for negotiations would be less than 120 days depending upon when the Decision is released leaving little time to resolve the outstanding issues, and there is also a possibility for further delays arising from disputes about whether parties are negotiating in good faith during that period. Second, he suggests that negotiations would divert important resources from other activities required to continue to move VITR forward. Third, he submits that aspects of the schedule for VITR would be affected. For example, negotiations with landowners could not commence until there was certainty the project was going to proceed. In addition, a conditional order could create uncertainties and delays in the EAO process.

Counsel for BCTC suggests that the Commission must also consider the reverse side of the issue, namely whether there is anything to be gained from further negotiations and analysis in the time available for accepting a cable tender and for solving the capacity shortfall on Vancouver Island. He rejects Sea Breeze's submission that the requirements suggested by BC Hydro and BCTC effectively preclude merchant solutions. He suggests the situation might be different if Sea Breeze had brought a more fully-formed application in front of the Commission. He indicates that BCTC's concerns with JdF extend well beyond the pricing and financing for JdF to much broader issues such as what may be the additional costs to ratepayers associated with JdF. He argues those broader issues would not be resolved through negotiations between BCTC and Sea Breeze.

Counsel for Sea Breeze concurs a "virtual certainty" test is not a matter of law but simply one of the considerations the Commission may include in its evaluation of project alternatives and in exercising its discretion with respect to the approval of a CPCN. He reiterates Sea Breeze's belief that JdF is a viable alternative to VITR. He also suggests there was still uncertainty surrounding VITR due to the possibility of various legal appeals. He expresses some doubt regarding the 120-day deadline in relation to the cable tenders, but also suggests that with good faith negotiations all of the issues associated with JdF could be dealt with in the time available. He also argues that Sea Breeze could not have been expected to bring forward a fully developed proposal in the absence of some support from BCTC and BC Hydro.

### 8.2.2 Financing of JdF

Concerns over the likely construction and potential use of JdF centred on the ability of Sea Breeze to secure financing, construction schedule risk associated with permitting of JdF, and the likelihood of BPA undertaking the necessary upgrades to its system to interconnect JdF and ensure a firm path to the Olympic Peninsula. The Commission Panel has dealt with construction schedule risks and BPA upgrade issues in Section 7 of the decision. This Section will address financing risks associated with JdF.

Sea Breeze acknowledges that it and its partners "…do not contest that contractual commitments will have to be secured before full financing of the JdF Project can be arranged" (Sea Breeze Reply, para. 44). Sea Breeze suggests that the Commission should recognize that the principal features of the JdF proposal to which BC Hydro refers in argument are features that would be present in any investor-funded merchant transmission proposal, including the presence of milestones under contractual arrangements with investors, the dependency of the proposal on system upgrades, the difference in the Commission's regulatory jurisdiction over a merchant transmission line contract, and the flexibility in determining the price of access to the project (Sea Breeze Reply, para.16). Sea Breeze further argues that if the Commission adopts BC

Hydro's proposed approach to whether it should consider JdF as an alternative to VITR, the practical effect would be to preclude the Commission from ever considering merchant transmission as an alternative to ratepayer-funded investment in transmission. Sea Breeze also extends this argument to the consideration of IPPs (Sea Breeze Reply, para. 18).

In assessing the financing prospects of JdF, the Commission Panel must establish the necessary test or criteria to meet for reaching a conclusion. The submissions received in this regard cover a broad spectrum. At one end of the range BC Hydro submits the construction of JdF will turn on a future assessment of EIF and of unidentified lenders, which has not been made yet and can only be made once the regulatory conditions associated with the project are known and all of the economic parameters of the project determined (BC Hydro Argument, para. 58). At the other end of the range, Sea Breeze submits that the question is not whether long-term arrangements must ultimately be in place to allow Sea Breeze to obtain financing for JdF, but whether or not it is reasonable to conclude on the evidence that if a contract with BCTC results from this process, there will be sufficient interest expressed by other parties wishing to purchase capacity on JdF that Sea Breeze will be able to obtain financing (Sea Breeze Argument, para. 108). This Section of the Decision reviews the Sea Breeze financial partners, summarizes the various positions of the parties and explains the rationale for findings.

#### 8.2.2.1 Energy Investors Funds ("EIF")

EIF is an established private equity fund manager, founded in 1987, dedicated exclusively to the independent power and electrical utility industry and is one of the world's leading investors in private power projects and companies. EIF has experience with independent regulated transmission development having provided equity financing for the Neptune project and the Path-15 Project. Sea Breeze states that EIF has been providing development funding to Sea Breeze and its partners on the JdF with a full understanding of the prevailing business conditions in BC and the Pacific Northwest (Exhibit B2-8, BCUC 1.2.1, p. 11).

EIF's investment strategy is to create geographically and technologically diversified portfolios of electric power-related assets that provide superior risk-adjusted equity returns with current cash flow and capital appreciation. The EIF approach is to acquire power generation and transmission assets with long-term off-take contracts. EIF relies mainly on its own sourcing of deals rather than participating in auctions. Finally, EIF seeks to achieve liquidity for its investors through regular cash distribution and proceeds from the sale of assets (Exhibit B2-8, BCUC 1.2.1, App. 1.2.1B).

Investors in EIF include pension funds, university endowments, other foundations, insurance companies and banks. The tax-exempt status of many of these investors as well as the structure of the private equity fund industry in general, with underlying different tax classifications, means that as a rule EIF performance is judged on the basis of generating a certain level of pre-tax return for investors (T40:7521-7522).

EIF investment decisions are made by the Investment Committee comprised of the seven EIF Managing Partners and Partners in keeping with typical institutional investor guidelines. The same decision making process applies for both the development funding and construction funding contemplated by EIF (Exhibit C31-53, BCTC 7). An analysis is prepared and presented to the Investment Committee by the deal team. The factors considered in the decision making progress include: the project, its location, technology, revenues, expenses, risks and other project specific issues that are relevant to the investment returns. The Investment Committee evaluates the investment in relation to the specific deal, the investment strategy of the Fund and its existing portfolio (Exhibit C31-53).

#### 8.2.2.2 Sociéte Général ("SocGen")

SocGen is one of the world's largest global financial institutions and is expected to arrange debt funding for JdF. It has served as both financial advisor and/or arranger for several important transmission projects, including the Path-15 Project and the Neptune Project. In addition, SocGen is also actively involved in financing major infrastructure development projects in British Columbia, including the RAV and Sea to Sky Projects (Exhibit B2-8, BCUC 1.2.1, p.10).

SocGen has acted as the financial advisor for Sea Breeze and prepared a financial model for JdF, which was also heavily relied on by EIF. The model assumptions were initially agreed to in the Spring of 2005 (T40:7508-7509).

8.2.2.3 Conditions for Financing

In reference to the testimony of the EIF witness from New York (T40:7490-7492), BCTC submits EIF indicated that having necessary permits in place for the upgrades on the Olympic Peninsula was a condition precedent for providing equity (and subsequently debt) financing for JdF (BCTC Argument, para. 83). BCTC further argues that even if Sea Breeze can persuade BPA to conduct the necessary Facilities Studies under BPS's tariff, there is no evidence of when the necessary environmental approval process would take place. Sea Breeze, as a potential transmission provider, is not qualified to make this request and has not identified anyone at the present time who is likely to make such a request and who has the financial capacity to do so (BCTC Argument, para. 84).

EIF reconfirmed that, as with any development, all material conditions must be satisfied before equity financing is provided (Exhibit C31-53, BCTC 8(b)). Once all relevant conditions and milestones have been met, and a project is ready for construction financing, the time required to complete the financing is generally within 30 to 90 days (Exhibit C31-54, BCTC 8(b)) The milestones with respect to equity funding were set out in the DLA (Exhibit C6-18, Schedule 1.3).

BC Hydro lists 20 of the pending conditions and parameters and points out how Sea Breeze also conceded that providers of debt financing would require these milestones to have been set and might impose additional requirements. BC Hydro further submits that while aspects of the financing package might receive further definition through conditional commitments containing conditions precedent, the evidence shows the only financing Sea Breeze can claim to have is the US$8.0 million identified in the DLA (BC Hydro Argument, para. 60-61).

Sea Breeze submits the principal features of the JdF proposal, addressed above, flow directly from the fact that JdF is a proposal for an investor-funded merchant transmission facility connecting two transmission systems – and would be present for virtually any such proposal. Accordingly, issues such as the dependency of JdF on certain upgrades to the BPA system and the presence of various milestones under the contractual arrangements between Sea Breeze and EIF are not unique (Sea Breeze Reply, para. 16). EIF has faced those issues before when dealing with other investor-funded proposals (Sea Breeze Reply, para. 28).

In order to assess the likelihood of obtaining equity and debt financing for JdF, one must also consider the magnitude and likelihood of various revenue streams, which are required to meet investor risk and return expectations. A key issue is whether a contract with BCTC would be sufficient to finance the project, and if not, what the likelihood of other revenues sources is.

Referring to Sea Breeze evidence, BCTC estimates that US$300 million of financing would be required for JdF to proceed. This estimate is based on the latest non-firm costs of JdF at US$225 million and the forecast additional US$77 to 100 million for BPA upgrades which Sea Breeze has offered to pay upfront. BCTC concludes that there is a significant gap between CDN$184 million (the amount BCTC might pay under a contract with Sea Breeze) and US$300 million and there is no certainty that JdF will be financed (BCTC Argument, para. 89, 94).

Sea Breeze argues that the testimony of EIF and SocGen clearly articulated their belief that if a contract were entered into between Sea Breeze and BCTC, JdF would be able to obtain the necessary equity and debt financing to allow it to proceed within the timeframe outlined by Sea Breeze (Sea Breeze Argument, para. 94). EIF testimony highlighted the other revenue opportunities it anticipates including the sale of ancillary services, other system benefits to other parties and the additional capacity. EIF further stated that once the cornerstone of the BCTC contract is achieved, it will reassess the other revenue opportunities to determine whether those contracts need to be in place at equity financing closing or whether EIF is willing to take the risk of allowing those contracts to fall in place subsequently, or even rely on market based revenue (T40:7494-7496).

Referring to the “if you build it they will come” theme, SocGen went even further in expressing confidence in JdF. While acknowledging that long-term commitments in addition to the BCTC contract would ultimately need to be secured, SocGen asserted that even a shorter 3-5 year contract with BCTC was sufficient to provide the necessary impetus to make JdF fully financable (T36:6927-6928).

BCTC submits that there is no evidence of a large number of parties prepared to contract for JdF. SocGen went through a detailed and well-publicized Open Season process for JdF. BCTC notes that only five parties registered to obtain access to the detailed bidding information on the Open Season website, and the only party that submitted a bid was an affiliate of Sea Breeze and did not meet the financial requirements for the bidding process. BCTC also submits a signed contract with BCTC “…does not make it any more likely that another customer or customers will subscribe for the significant quantity of N-S capacity that would be necessary to have any prospect of having JdF financed” (BCTC Argument, para. 90). BCTC submits that customers would require a long-term contract with a credit-worthy purchase in the U.S. before they could commit to service on JdF, and none has yet been able to secure a long-term export contract.

Sea Breeze argues that the negative outcome of the Open Season process was not a surprise and is not a concern because customers would likely be secured through bilateral negotiations rather than through the Open Season process (Sea Breeze Argument, para. 102).

In an undertaking filed in response to questions by the Intervenors, Commission staff and the Commission Panel, Sea Breeze indicated that it believes the Sea Breeze Energy Inc.’s bid, or an equivalent bid, combined with a minimum guaranteed revenue stream from BCTC of $22.3 million per year (nominal dollars) for 20 years, or $17 million annually for 40 years, together with expected revenues from the additional system benefits outside of B.C., increased transfer capacity over the Blaine Intertie, and benefits to the Olympic peninsula would allow Sea Breeze and its investors to proceed with the development of JdF (Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093).

Sea Breeze submits it will accept the Commission's determination as to the level of indirect costs for VITR, which may fairly be included in determining the level of compensation. In particular, Sea Breeze emphasizes that the viability of JdF is independent of whether or not the Commission determines that any or all of the system benefits regarding the BCTC system claimed by Sea Breeze should be included (Sea Breeze Argument, para. 65).

**Commission Determination**

The Commission Panel rejects the idea that a merchant project must be financed or even constructed prior to being given due consideration as an alternative means to meeting ratepayer needs. The Commission Panel is persuaded by the 'anchor tenant' argument of Sea Breeze which indicates that EIF may indeed be willing to take the equity risk even if the only signed contract were with BCTC. Further, the requirement for such a contract with BCTC does not necessarily alter the merchant nature of the project. The price would still be based on BCTC's next best available alternative to meet ratepayer needs, which may be a reasonable "market test." Further, investors in the merchant project would still be assuming risk for overall returns, which would be dependent on secondary revenues.

The Commission Panel accepts the comments of BCTC, BC Hydro, and Sea Breeze that a "virtual certainty" test is not a matter of law, but merely one of the facts the Commission Panel may consider in exercising its discretion in determining if a particular project is in the public interest. In this regard, the Commission Panel does not accept an absolute test for certainty, but rather it views the test as a relative one. That is, it is the relative certainty among available alternatives that should be considered. Further, the weight that may be given to certainty in a particular decision is also dependent in part on the context of the decision, e.g., the form, level and timing of a ratepayer need.

In the case of the current decision before the Commission, the Commission Panel finds that the level and timing of the capacity shortfall on Vancouver Island suggests a high weight should be given to certainty for reliability planning purposes. The Commission Panel accepts the arguments of BC Hydro and BCTC regarding the Commission's broad powers under the *UCA* in relation to BCTC and VITR, and also considers the project considerably more developed than JdF. The Commission Panel does not consider VITR "virtually certain" in that the project is still dependent on other regulatory approvals (e.g., the Environmental Assessment process), but the Commission Panel considers these uncertainties are much smaller for VITR in comparison to JdF.

The Commission Panel also notes that, in situations where certainty has high weight and the benchmark project establishes a high bar, there may still be other ways for merchant proposals to address concerns over certainty short of securing full financing and all permits. For example, it may be possible for a merchant project to mitigate the risk of additional costs ratepayers arising from a failure to ultimately finance or construct the merchant project through the provision of a bond or other security to cover the cost of additional bridging measures and any higher costs arising from delaying a utility-funded alternative. In this case, Sea Breeze has proposed a performance bond related to construction risk (Exhibit C31-57, Undertaking T40:7501, 7505-7506; Sea Breeze Argument, para. 119-121) but it has not proposed a security to mitigate the risks of delay to VITR arising from contract negotiations and financing milestones.

With respect to financing risk for JdF, the Commission Panel notes that the PV of an annual nominal payment (@ a nominal discount rate of 8 percent) of $22.3 million over 20 years (the minimum guaranteed payment required by Sea Breeze to secure financing for JdF in Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093) is equivalent to $219 million in 2009/10 or $201 million in constant $2005. That exceeds the lump sum payment for JdF estimated by the Commission Panel in Section 7 of the Decision. Alternatively, if the lump sum payment of $178 million for JdF calculated by the Commission Panel in Section 7 was converted to a 20-year annuity at an 8 percent nominal interest rate, the annual payment would be approximately $18 million, which is less than the minimum payment required by Sea Breeze. Similarly, the present value of the 40-year minimum payment also exceeds the lump sum payment calculated by the Commission Panel in Section 7 and a 40-year annuity of the lump sum payment would not equal the minimum amount Sea Breeze indicates it would require to secure financing.

This simple analysis suggests that the proposed pricing formula and cost determinations made by the Commission Panel could not meet the threshold suggested by Sea Breeze. Further, the Commission Panel notes that even if the thresholds were met, according to Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093 financing would also be contingent on the Sea Breeze Energy Inc.'s bid for N-S capacity, or an equivalent bid, combined with expected revenues from the additional system benefits outside of B.C., increased transfer capacity over the Blaine Intertie, and benefits to the Olympic peninsula would allow Sea Breeze and its investors to proceed with the development of JdF (Exhibit C31-57, Undertaking T36:6857-6858, 7037, 7091-7093).

The Commission Panel shares BCTC and BC Hydro's concerns about the likelihood of third party revenues given the results of Sea Breeze's Open Season. Although Sea Breeze stated in Argument that the outcome of the Open Season process was not a surprise, the Commission Panel notes that in response to questions posed by Counsel for BCTC, Sea Breeze testified that it was "…hopeful that we would have gotten a better response in terms of firm bids than we did…" (T31:5795). Further, the Commission Panel also concurs with BC Hydro that the references to notification of bid awards to major successful open season bidders in the DLA with EIF (Exhibit C6-18, Schedule 1.3) suggests some expectation on the part of Sea Breeze's financiers of successful bids arising from the Open Season.

The Commission Panel finds that, based on the record in this proceeding, there would still be considerable uncertainty regarding these other conditions for financing, at least within the timeframe within which the capacity is required by BCTC. Further, even if financing for JdF could be secured with the proposed pricing formula and Commission Panel determinations in Section 7 of the Decision, the Commission Panel notes that the PV savings suggested by Sea Breeze's proposed pricing formula would not be sufficient to offset the other costs to ratepayers for incremental losses, static VAr compensation, and wheeling costs in the U.S. associated with relying on JdF for contingency planning purposes.

In practical terms, in recognition of the numerous milestones to be met, the Commission Panel also cannot assume that financing would be available for JdF in 90 days from contract signing. The Commission Panel also notes that, based on EIF testimony, EIF has given limited consideration to the JdF since March 2005. The Commission Panel accepts the BC Hydro submission that ultimately the construction of JdF will turn on a future assessment of EIF, which will be made once the regulatory conditions and the economic parameters of the project are known. Besides the financial projections for the JdF, the EIF decision will also be influenced by other competing projects available at the time and funds requiring reinvestment.

The Commission Panel further accepts the EIF description of the Investment Committee decision making process within the institutional investor guidelines, its due diligence work and the considerable emphasis on risk assessment. The Commission Panel also appreciates the mutual respect and team work between EIF and Sea Breeze as well as their previous success with the Neptune project. The significant effort by Sea Breeze from September 2005 to May 2006 in connection with this proceeding has increased the understanding of the key variables influencing the financial model, which now can be readily updated. The oral phase of the proceeding further enhanced the understanding of the risk assessment, which ultimately will influence the EIF decision.

In conclusion, the Commission Panel finds that if, due to this Decision and direction, JdF were able to get a long-term, regulated contract with BCTC, there is still uncertainty relative to VITR as to whether Sea Breeze would be able to secure financing in the time required to meet ratepayer needs. More importantly, the proposed pricing of JdF and minimum guaranteed payment required by Sea Breeze do not provide sufficient savings to ratepayers to offset other costs associated with reliance on JdF to meet reliability planning criteria for Vancouver Island.

## 9.0 COST CONTROL/INCENTIVE MECHANISM

BCOAPO first raised the issue of a mechanism to ensure, to the extent possible, that potential cost overruns of VITR are limited or at least that their impact on ratepayers is limited (T6:834). A further cross-examination of this topic with BCTC's Policy Panel resulted in an introduction of a proposed penalty/incentive mechanism by BCTC (Exhibit B1-64).

### 9.1 VITR Incentive/Penalty Mechanism

In response to the request by the Commission Panel, BCTC submitted an incentive/penalty mechanism, emphasizing that it should apply solely to VITR and not to any other projects undertaken by BCTC. BCTC also stated that its preference still was for no mechanism. The key characteristics of this proposal are outlined as follows:

- The mechanism should reference project costs that are prepared to a P80 estimate quality.
- There should be a limited opportunity for BCTC to seek BCUC approval of changes to the targeted levels to reflect events that are beyond BCTC's control.
- The prudence assessment of BCTC management will take place in future revenue requirement proceedings.

**Table 9-1: Initial VITR Incentive / Penalty Framework Proposed by BCTC**

| Variance from Budget Cost | Portion of Revenue Requirement As Incentive/Penalty |
|---|---|
| Less than plus/minus 10% | No incentive or penalty |
| Between plus/minus 10 to 20% | 40% of the equity return component of BCTC's 2008 revenue requirement |
| Greater than plus/minus 20% | 75% of the equity return component of BCTC's 2008 revenue requirement |

Subsequently, BCTC modified its proposal by confirming that there was no intention of providing for a disproportionate opportunity for an incentive versus a penalty. BCTC explained that the reference to a P80 estimate quality was intended to refer to an estimate with a greater degree of precision than the target estimate provided in the Application (T19:3444-3446). This can be accomplished, for instance, by setting the target after receipt of results of the tendering process or at the time of signing of the agreement which could be in 60 days after receipt of tenders (T15:2439-2441).

While BCTC continues to believe that an incentive/penalty mechanism is not necessary or appropriate for VITR it filed a further refinement of the above method, in response to an invitation from the Commission Panel (Exhibit B1-114).

**Table 9-2: Modified VITR Incentive / Penalty Framework Proposed by BCTC**

| Variance from Threshold | Incentive/Penalty |
|---|---|
| Below P10 $223.1 million | + 25% of equity return component |
| Above P90 $279.5 million | - 25% of equity return component |

Assuming a F2009 return on equity component included in the BCTC revenue requirement of $7.2 million, a potential penalty or incentive amount under this mechanism would be $1.8 million.

### 9.2 Prudency Review vs. Incentive/Penalty Mechanism

The Commission Panel explicitly wanted to have this matter addressed as it has relevance not only to VITR but perhaps to future BCTC projects and even to the style of regulation in relation to post-CPCN filings. It is feasible that if the Commission was to establish an appropriate incentive/penalty mechanism, the on-going regulatory review of the project could become less important (T15:2428).

In prudency reviews the test is in terms of recovery of capital expenditure funds spent pursuant to a CPCN, whether or not the Applicant has been imprudent. An incentive/penalty mechanism, on the other hand, is intended to reward or penalize good or poor management respectively. In a prudency review, BCUC could find the quality of management inadequate but allow recovery of costs, nevertheless, because the threshold of imprudence had not been crossed. Furthermore, in the CPCN process, prudency reviews are the exception rather than the rule (T15:2429-2431).

### 9.3 Intervenor Submissions

BCOAPO is concerned that some mechanism to protect ratepayers be implemented for VITR or any similar project for which the Commission grants a CPCN to BCTC. BCOAPO submits that ratepayers are in the same position regardless of the utility's ultimate ownership (crown vs. investor-owned) and that the nature of that ownership should not, in itself, be a reason for not introducing a cost control mechanism. BCOAPO also highlights some deficiencies in the BCTC proposal which include the determination of the target cost and applicability of the mechanism in the case of multiple major projects being undertaken simultaneously. In conclusion, BCOAPO supports the Commission establishing a cost control mechanism similar to that established in the May 21, 1999 Southern Crossing Pipeline Project Decision (BCOAPO Argument, pp. 19-21).

BC Hydro submits that due to the investment structure of VITR it would be wholly inappropriate to introduce a cost control mechanism and raised the following arguments:

1. "The only party, other than ratepayers, able to assume risk in connection with VITR construction costs is BC Hydro. Thus, the real question is whether ratepayers should pay BC Hydro to assume risk on cost overruns.

2. A precedent on this issue has already been set in the Heritage Contract proceeding where Intervenors took the position that paying a risk premium to BC Hydro was inefficient.

3. A variance from the Heritage Contract Decision would require the introductions of a risk premium. This change would, in turn, lead into restructuring of regulation of BC Hydro which is not within the Commission's jurisdiction.

4. The circumstances surrounding the Southern Crossing project were fundamentally different. For instance, that project was designed to provide regulated and unregulated benefits to its owner" (BC Hydro Reply, pp. 9-10).

BCOAPO does not agree that the risk premium issues raised in the context of the Heritage Contract are applicable in the case of VITR and argues that the Southern Crossing was, like VITR, a response by a utility to provide additional service (T42A:7983-7984).

**Commission Determination**

The Commission Panel finds that a test applied in a prudency review is very different from a test for a mechanism which is designed to encourage good management. The key objectives of an incentive/penalty mechanism are risk sharing, fairness and an alignment of ratepayer and utility interests in a symmetrical manner. The mechanism should have financial and reputational consequences to BCTC in case of non-performance and should offer strong incentives to project team members to strive for peak performance.

The Commission Panel observes the confusion that surfaced during the evidentiary portion of the proceeding in February 2006 regarding the project oversight. The Executive Sponsor had retired and the new Executive Sponsor was not available to testify as a member of the Policy Panel (T14:2392-2393). Furthermore, among the BCTC executives there was even perplexity over who the Executive Sponsor was and what the role of the Executive Sponsor is vis-à-vis Program Manager (T16:2724-2725).

The concerns regarding the VITR Project Team and the route selection process, as well as concerns expressed by Sea Breeze, led to the rare invitation to the BCTC CEO to appear before the Commission Panel. The Chair inquired whether BCTC has been dismissive of both Sea Breeze and the Utilities Commission (T16:2718). BCTC admits that there has been significant turnover at the executive level over a short period of time (BCTC Argument, para. 58).

In view of the confusion, senior management turnover, a significant number of BC Hydro staff working with BCTC on VITR and the project challenges, the Commission Panel believes it is in the interest of ratepayers to introduce an incentive/penalty mechanism to ensure that this major project receives the focus, attention and direction it requires for an on-time, on-budget delivery.

Regardless the asset ownership structure, the Commission Panel further believes that the mechanism by definition can only be meaningful and effective when it applies to the entity responsible for project execution, which is BCTC. The Commission Panel does not accept the arguments of BC Hydro [on this issue] and also notes that during the Oral Argument Phase BC Hydro accepts BCTC's own assessment of its ability take on financial risk as identified in its two proposals (T42A:7980-7982).

The Commission Panel accepts BCTC's argument that the design of a mechanism encompassing more capital projects other than just VITR is more complex and should only be determined through a separate proceeding established for that purpose. Accordingly, the Commission Panel finds that the incentive/penalty amount of +/-25 percent of BCTC's approved return on equity component for F2009, as proposed in the Modified Framework, is appropriate for VITR but that the proposed cost threshold requires further refinement.

The Commission Panel notes that the uncertainty over the final costs of VITR will be greatly reduced by the award of the cable contract, which makes up more than 50 percent of the project costs and which BCTC expects will not be any higher than the lowest read out tender cost of $135.3 million (Exhibit B1-135). The Commission Panel also notes that its Decision to approve Option 1 through South Delta, with a secured ROW, provides the highest level of project definition and cost certainty relative to the other options that were being considered. In these circumstances, it would be unexpected for the actual project costs to fall significantly outside the P90-P10 range. Even then, the Commission Panel believes that a mechanism will serve a purpose.

The Commission Panel finds that the threshold for the incentive should be based on the P10 and P90 estimates for VITR expressed in nominal dollars. It has calculated a P90 estimate for VITR of $251 million in nominal dollars based on Option 1 through South Delta, including a 5 percent contingency on the lowest cable tender provided by BCTC in Exhibit B1-135. The Commission Panel has insufficient information to calculate a comparable P10 estimate reflecting Option 1 through South Delta and the results of the cable tender. **The Commission Panel therefore orders BCTC to provide for approval by the Commission, within 30 days of a signed cable**

**tender and no later than 90 days from this Decision, final P10 and P90 nominal dollar estimates for VITR that reflect the route option approved in this Decision and the signed cable tender. The estimates should be provided in a format similar to the P50 and P90 summary provided in response to Sea Breeze 2.45.1 in Exhibit B1-44. The estimate should show all adjustments made to reflect the final cable contract and there should no longer be any contingency included on the cable contract. In addition to the adjustments reflecting the final submarine cable contract, BCTC should clearly identify in its filing, with explanation, any other variances it makes to the P10 and P90 estimates for Option 1 through South Delta relative to the costs filed as part of this proceeding (Exhibit B1-1).**

## 10.0 THE TRAHVOL COMPLAINT

On November 8, 2005 TRAHVOL filed a Complaint with the Commission pursuant to Section 25 of the *UCA* (Exhibit C3-21). In that Complaint TRAHVOL submitted that the continued operation of the two 138 kV transmission lines through the community of Tsawwassen is unreasonable, unsafe, inadequate or unreasonably discriminatory, and requested that the Commission hold a hearing into the Complaint and further proposed that the Complaint hearing be part of the VITR CPCN proceeding.

In support of its Complaint TRAHVOL stated that it would demonstrate that, on the basis of EMF levels along the Tsawwassen portion of the ROW, the latest scientific research regarding the effects of EMF on public and animal health, and the impact on property values of recent heightened awareness of EMF levels and research, there is compelling evidence that the lines are unreasonable, unsafe, inadequate or unreasonably discriminatory. TRAHVOL stated that it intended to rely on evidence that it had submitted as an Intervenor in this proceeding to support its Complaint.

The Commission Panel accepted the Complaint and determined that it would properly be heard as part of this hearing (Exhibit A-36).

In its Argument, TRAHVOL reiterates its Complaint and submits that the Commission should order removal of the existing lines because of concerns about the seismic stability of the poles, the continued uncertainty around the health effects associated with EMF, and the negative impact on property values that results from that uncertainty and stigma (TRAHVOL Argument, para. 138-39).

BCTC submits that TRAHVOL's submissions do not support its assertions that the existing lines are unreasonable, inadequate, or unreasonably discriminatory. BCTC and BCOAPO both submit that the only possible basis on which TRAHVOL may bring its Complaint is with respect to the issue of safety, and that the onus is on TRAHVOL to establish the basis for its Complaint.

BCTC and BCOAPO argue that TRAHVOL has failed to establish that safety issues related to the existing lines are sufficient to warrant their removal (BCOAPO Reply, para. 14; BCTC Reply, para. 209-10).

In Reply, TRAHVOL made further submissions regarding EMF levels and scientific uncertainty, and argued that prudent avoidance and the precautionary principle support relocation of the transmission lines (TRAHVOL Complaint Reply).

**Commission Determination**

In this Decision, a CPCN is granted for VITR as modified by Option 1 through South Delta and therefore both of the existing 138 kV lines through Tsawwassen will be replaced by the new double-circuit line on single steel pole structures. Nevertheless, the Commission Panel addresses TRAHVOL's complaint here because many of TRAHVOL's concerns apply equally to Option 1.

The Commission Panel concludes that TRAHVOL has not provided any evidence from which it can be determined that the existing 138 kV lines through Tsawwassen are unreasonable, inadequate or unreasonably discriminatory.

TRAHVOL has provided submissions regarding safety issues. The Commission Panel has considered the issue of public health effects from EMF in Section 5.2. To reiterate those findings, the Commission Panel determines that the scientific research does not support TRAHVOL's assessment of EMF-related health risks, and notes that EMF levels along the ROW are well below established guidelines and are not uniquely high.

On the issue of pole safety, the Commission Panel notes that TRAHVOL's concern stems, in part, from the fact that the existing structures were constructed at an early stage of seismic design. While the Commission Panel does not conclude that the existing poles are unsafe, it notes that approval of Option 1 will result in the replacement of both existing lines with up-to-date steel pole structures. The issue of overhead transmission line safety was addressed in

Section 5.1 where the Commission Panel directs BCTC to address seismic loading in the design of the overhead segments of VITR.

**As a result of these determinations, the Commission Panel denies the Complaint.**

## 11.0 SUMMARY OF CONCLUSIONS AND DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Conclusions and Directives in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

| | **Conclusion/Directive** | **Section** | **Page** |
|---|---|---|---|
| 1. | Given the need for a project to provide adequate and reliable power to Vancouver Island customers, the Commission Panel concludes that it is in the public interest that the most cost-effective alternative be selected from amongst the competing alternatives. Further delay in finding a solution for Vancouver Island customers is not an option that is in the public interest. Moreover, all the alternative solutions for Vancouver Island customers have adverse impacts. The alternatives, including VITR with its several route options, VIC, and JdF, need to be compared to determine the best, most cost-effective means of supplying power to Vancouver Island. Each alternative has different impacts on interests; some of those interests may be considered public interests and others are private interests. The Commission Panel is of the opinion that both public and private interests should be considered in selecting the project alternative and route option that is in the public interest, although the relative weight placed on the different interests may vary. | 2.1 | 16 |
| 2. | The Commission Panel concludes there is already sufficient evidence on the record regarding the Vancouver Island load forecast and that the February 2006 forecast was available when the record was open. | 2.4 | 27 |
| 3. | The Commission Panel concludes that EMF concerns do not warrant actions beyond the very low cost measures that BCTC has included in its VITR design. | 5.2.6 | 71 |
| 4. | The Commission Panel directs BCTC to file a public report with the Commission every two years, or sooner if there are major developments in the field, that summarizes the latest results of EMF risk assessments and any changes in guidelines developed by the World Health Organization, ICNIRP, Health Canada and others where relevant. | 5.2.6 | 72 |

| | | | |
|---|---|---|---|
| 5. | The Commission Panel also finds that the disadvantages of the wood H-frame option outweigh the cost advantage, and therefore directs BCTC to implement Option 1 as described in the Application. | 6.4 | 105 |
| 6. | The Commission Panel directs BCTC to establish an account for what it considers conforming restoration costs and another account for what it considers non-conforming restoration costs. | 6.6 | 112 |
| 7. | The Commission Panel directs BCTC to study the transient stability of the approved project and to file with the Commission by December 31, 2006, a report documenting the security characteristics of the approved project and confirming that there are no other system upgrades required to ensure acceptable transient performance in the southern Vancouver Island transmission system. | 7.2 | 127-128 |
| 8. | The Commission Panel accepts the VIC loss calculation in Exhibit B1-56, BCUC 3.184.3 (revised), and the annual incremental loss cost of $2.4 million per year of VIC over VITR. | 7.6 | 145 |
| 9. | The Commission Panel determines that a reasonable approximation for the incremental losses associated with JdF over VITR can be calculated by taking half of the incremental losses associated with the “No VITR or VIC” case in Exhibit B1-56, BCUC 3.184.3 (revised), and adding half of an additional 5.5 MW and 45.8 GW.h for the PIK JdF converter to be kept in standby or on-line mode. | 7.6 | 145-146 |
| 10. | The Commission Panel determines it is not prudent to construct a permanent bypass facility at ARN to enable the connection of the VITR line to an ING-ARN 230 kV line, and does not assign any monetary benefit to either JdF or VIC for avoiding any upgrade work at ARN intended to make it more secure against seismic events. | 7.7.1 | 147-148 |
| 11. | The Commission Panel determines that two of the four VIT synchronous condensers could be shut down in the presence of an HVDC Light® converter station at PIK, so VIC or JdF should be assigned an annual benefit of half of $748,000, or $374,000, per year for the purposes of comparative analysis against VITR, provided that sufficient static reactive support is installed in the HVDC Light® converter to allow the provision of dynamic reactive support across its full output range. | 7.7.2 | 150 |

| | | | |
|---|---|---|---|
| 12. | For the purposes of project comparisons, the Commission Panel determines that a benefit of $30 million for Lower Mainland dynamic reactive power supply should be assigned to VIC as compared to VITR, and that no benefit should be assigned to JdF. | 7.7.4 | 155 |
| 13. | The Commission Panel determines that BCTC's assessment of at least $12 million as the cost that should be added to either VIC or JdF, to represent the one-year advancement from 2017 to 2016 of a second transmission capacity addition because of their lower transmission capacity as compared to VITR, is appropriate. | 7.7.6 | 160 |
| 14. | The Commission Panel orders BCTC to provide for approval by the Commission, within 30 days of a signed cable tender and no later than 90 days from this Decision, final P10 and P90 nominal dollar estimates for VITR that reflect the route option approved in this Decision and the signed cable tender. The estimates should be provided in a format similar to the P50 and P90 summary provided in response to Sea Breeze 2.45.1 in Exhibit B1-44. The estimate should show all adjustments made to reflect the final cable contract and there should be no longer any contingency included on the cable contract. In addition to the adjustments reflecting the final submarine cable contract, BCTC should clearly identify in its filing, with explanation, any other variances it makes to the P10 and P90 estimates for Option 1 through South Delta relative to the costs filed as part of this proceeding (Exhibit B1-1). | 9.3 | 206-207 |
| 15. | The Commission Panel denies the TRAHVOL Complaint. | 10.0 | 210 |

Dated at the City of Vancouver, in the Province of British Columbia, this 7th day of July 2006.

*Original signed by:*

Robert H. Hobbs
Chair

*Original signed by:*

Nadine F. Nicholls
Commissioner

*Original signed by:*

Liisa A. O'Hara
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER C-4-06

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Transmission Corporation
for a Certificate of Public Convenience and Necessity
for the Vancouver Island Transmission Reinforcement Project

**BEFORE:** R.H. Hobbs, Chair
N.F. Nicholls, Commissioner July 7, 2006
L.A. O'Hara, Commissioner

**CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY**

**WHEREAS:**

A. By application dated July 7, 2005, the British Columbia Transmission Corporation ("BCTC") requested that the British Columbia Utilities Commission (the "Commission") grant a Certificate of Public Convenience and Necessity ("CPCN") pursuant to Sections 45 and 46 of the Utilities Commission Act (the "Act"), for the Vancouver Island Transmission Reinforcement Project (the "VITR") to reinforce the electric transmission system serving Vancouver Island and the Southern Gulf Islands (the "VITR Application"); and

B. By Order No. G-70-05, the Commission established a Procedural Conference on August 4, 2005 regarding the regulatory process for the review of the VITR Application; and

C. By Order No. G-72-05, the Commission Panel established the Regulatory Timetable that included a Pre-hearing Conference, Town Hall Meetings, and an Oral Hearing to review the VITR Application; and

D. On September 30, 2005 Sea Breeze Regional Transmission System, Inc. [now Sea Breeze Victoria Converter Corporation ("Sea Breeze")] filed a CPCN application (the "VIC Application") for the Vancouver Island Cable Project (the "VIC") and requested that the Commission confirm the consolidation of the review of its VIC Application with the BCTC VITR proceeding. The Commission issued a separate procedural Order No. G-97-05 to initiate the regulatory review of the Sea Breeze VIC Application; and

E. By Order No. G-96-05, the Commission Panel revised the Regulatory Timetable for the review of the VITR Application, established Pre-hearing Conference No. 2 for October 21, 2005 and ordered Sea Breeze to file any further motion that it desired to be considered at Pre-hearing Conference No. 2; and

F. Following Pre-hearing Conference No. 2, the Commission Panel issued Order No. G-109-05 that established a Revised Regulatory Timetable for the review of the VITR Application which assumed that a consolidated process would be used to review the VITR and VIC Applications, and established Pre-hearing Conference No. 3 for November 10, 2005; and

G. By letter dated November 8, 2005 Tsawwassen Residents Against High Voltage Overhead Lines ("TRAHVOL") filed a complaint pursuant to Section 25 of the Act that the continued operation of the existing 138 kilovolt lines through Tsawwassen is unreasonable, unsafe, inadequate or unreasonably discriminatory, and requested that the Commission hold a hearing into the complaint; and

H. At Pre-hearing Conference No. 3 the Chair granted the application by Sea Breeze for the consolidation of the proceedings for the VITR Application and the VIC Application, and maintained the Revised Regulatory Timetable that was established by Order No. G-109-05. In addition, counsel for TRAHVOL accepted a proposal by the Panel Chair that the TRAHVOL Section 25 complaint be considered within the scope of the proceeding to review the VITR and VIC Applications; and

I. By Order No. G-141-05, the Commission Panel issued a Revised Regulatory Timetable for the proceeding, which delayed the start of the Public Hearing to February 6, 2006; and

J. Town Hall Meetings were held on Salt Spring Island on January 7, 2006 and in Tsawwassen on January 14, 2006; and

K. Opening Oral Submissions took place on January 30, 2006 and Submissions on the Proponent Consolidation of the Hearing Issues List took place on February 1, 2006; and

L. The Hearing Issues List was issued on February 3, 2006, and the Public Hearing commenced on February 6, 2006 in Vancouver; and

M. Sea Breeze withdrew its VIC Application on March 1, 2006; and

N. The evidentiary phase of the proceeding closed on March 23, 2006; and

O. By letter dated March 27, 2006, the Commission approved a request from BCTC to strike evidence from the record due to the withdrawal of the Sea Breeze VIC Application; and

P. The Written Argument phase of the proceeding was completed when BCTC filed its Reply Submission on May 16, 2006; and

Q. The Oral Phase of Argument, including submissions regarding motions by a number of parties, was heard on May 30 and 31, 2006; and

R. The Commission Panel has considered the VITR Application and the evidence and submissions presented on the Application and has determined that it is in the public interest that a CPCN be issued to BCTC for the VITR as modified by and subject to the conditions and directions set out in this Order and the Decision that is issued concurrently with it.

…/3

**NOW THEREFORE** pursuant to Sections 45 and 46 of the Act the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to BCTC for the VITR as described in the VITR Application and modified by the Decision issued concurrently with this Order, including overhead construction of the line in Tsawwassen and on the Gulf Islands. The CPCN is subject to the condition that the modified cost control/incentive mechanism described in Section 9 of the Decision apply to the project.

2. BCTC file for Commission approval, within the earlier of 30 days after signing the cable tender contract or 90 days of the date of this Order, final P10 and P90 nominal dollar cost estimates for VITR as described in Section 9 of the Decision that reflect the routing approved in the Decision issued concurrently with this Order and the signed cable tender contract.

3. BCTC comply with the directions of the Commission in the Decision issued concurrently with this Order, including the establishment of separate accounts to record conforming and non-conforming restoration costs.

4. BCTC file with the Commission quarterly progress reports on the VITR project schedule and costs, followed by a final report on project completion. BCTC will determine the form and content of the reports in consultation with Commission staff.

5. The TRAHVOL complaint filed by letter dated November 8, 2005 and made pursuant to Section 25 of the Act is dismissed.

**DATED** at the City of Vancouver, in the Province of British Columbia, this 7th day of July 2006.

BY ORDER

*Original signed by:*

Robert H. Hobbs
Chair

# LIST OF ACRONYMS

| | |
|---|---|
| 51 Percent Proposal | As described by BCTC at BCTC Argument, paragraph 3 |
| ac | Alternating Current |
| AIA | Archaeological Impact Assessment |
| AIP | Agreement in Principle filed as Exhibit B1-89 |
| AOA | Archaeological Overview Assessment |
| Application | Exhibit B1-1 |
| ARN | Arnott Substation |
| ATC | Available Transmission Capability |
| BC Hydro | British Columbia Hydro and Power Authority |
| BCAA | British Columbia Assessment Authority |
| BCOAPO | BC Old Age Pensioners Association, et al |
| BCTC | British Columbia Transmission Corporation |
| BPA | Bonneville Power Administration |
| Campbell | Bradley W. Campbell |
| CEC | Commercial Energy Consumers of British Columbia |
| CFT | Vancouver Island Call for Tenders |
| CFT Decision | Call for Tenders for Capacity on Vancouver Island and Review of Electricity Purchase Agreement – Order No. E-1-05 and Reasons for Decision |
| Commission, BCUC | British Columbia Utilities Commission |
| CPCN | Certificate of Public Convenience and Necessity |
| Customer Class Group | CEC, BCOAPO and JIESC, collectively |
| dc | Direct Current |
| Delta | Corporation of Delta |
| DLA | Development Loan Agreement |
| DMR | Dunsmuir Substation |
| DSB | Downstream Benefit |
| EAA | Environmental Assessment Act |
| EAC | Environmental Assessment Certificate |
| EAO | Environmental Assessment Office |

| | |
|---|---|
| EENS | Expected Energy Not Served |
| EIF | Energy Investors Fund |
| EMF | Electromagnetic Fields **or** Electric and Magnetic Fields |
| EPC | Engineering Procurement and Construction |
| FOR | Forced Outage Rate |
| GW.h | Gigawatt-hours |
| HDD | Horizontal Directional Drilling |
| Holmsen | Karsten Holmsen |
| HTG | Hul'qumi'num Treaty Group |
| HVDC | High Voltage Direct Current |
| Hz | Hertz |
| IARC | International Agency for Research on Cancer |
| ICNIRP | International Commission on Non-Ionizing Radiation Protection |
| IDC | Interest During Construction |
| IEEE | Institute of Electrical and Electronics Engineers |
| IEP/LTAP | Integrated Electricity Plan and Long-term Acquisition Plan |
| ING | Ingledow Substation |
| IPPs | Independent Power Producers |
| IR | Information Request |
| IRAHVOL | Island Residents Against High Voltage Overhead Lines |
| JdF | Juan de Fuca |
| JIESC | Joint Industry Electricity Steering Committee |
| kV | Kilovolts |
| Maracaibo | Owners of Strata Plan 905 and Shareholders of Maracaibo Estates Ltd. |
| mG | Milligauss |
| MVAr | Megavolt-amperes reactive |
| MW | Megawatts |
| MW.h | Megawatt-hours |
| Nam | Kyong H. Nam |
| NEB | National Energy Board |

| | |
|---|---|
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Council |
| NITS | Network Integrated Transmission Service |
| O&M | Operations and Maintenance |
| OATT | Open Access Transmission Tariff |
| PACA | Participant Assistance/Cost Award |
| PGA | Peak Ground Acceleration |
| PIK | Pike Lake Substation |
| PST | Phase Shifting Transformer |
| PV | Present Value |
| ROW | Right-of-way |
| RRA | Revenue Requirements Application |
| SBP-RTS | Sea Breeze Pacific Regional Transmission System, Inc. |
| SDSS PAC | South Delta Secondary School Parent Advisory Council |
| Sea Breeze | Sea Breeze Victoria Converter Corporation |
| SocGen | Sociéte Général |
| Socioeconomic and non-financial considerations | Encompasses non-financial ratepayer considerations such as reliability and risk, as well as broader community considerations such as impacts on safety, health, environment, and aesthetics |
| SVC | Static VAr Compensator |
| T36: 6840 | Transcript Volume 36, page 6840 |
| TBY | Taylor Bay Terminal |
| TFN | Tsawwassen First Nation |
| the Act, UCA | Utilities Commission Act |
| TRAHVOL | Tsawwassen Residents Against Higher Voltage Overhead Lines |
| VAr | Volt-amperes reactive |
| VIC | Vancouver Island Cable Project |
| VIC-Vancouver Island Cable Project | Used to refer to the VIC Project first proposed by Sea Breeze and also to the VIC-like alternative considered following withdrawal of Sea Breeze’s CPCN Application |
| VIGP | Vancouver Island Generation Project |
| VIT | Vancouver Island Terminal |

| | |
|---|---|
| VITR | Vancouver Island Transmission Reinforcement Project |
| WECC | Western Electricity Coordinating Council |

# APPEARANCES

| | |
|---|---|
| G.A. FULTON | Commission Counsel |
| A.W. CARPENTER<br>C. BYSTROM | British Columbia Transmission Corporation |
| P.J. LANDRY<br>J. HERBERT | Sea Breeze Pacific Regional Transmission System Inc.<br>Sea Breeze Victoria Converter Corporation |
| C.W. SANDERSON<br>C. GODSOE<br>H.M. CANE | British Columbia Hydro and Power Authority |
| R.B. WALLACE<br>S. HANSEN | Joint Industry Electricity Steering Committee |
| D. CRAIG | Commercial Energy Consumers Association of British Columbia |
| R. GATHERCOLE | B.C. Old Age Pensioners' Organization, Council of Senior Citizens' Organizations, Federated Anti-Poverty Groups of British Columbia, End Legislated Poverty, B.C. coalition of People with Disabilities, Active Support Against Poverty, and Tenants' Rights Action Coalition |
| K. JOHNNIE | Hum'qumi'num Treaty Group |
| J. YARDLEY | Corporation of Delta |
| B. KUDZIN | South Delta Secondary High School Parent Advisory Council |
| J. ARVAY, Q.C.<br>M. UNDERHILL | Tsawwassen Residents Against Higher Voltage Overhead Lines (TRAHVOL) |
| D. AUSTIN | Island Residents Against Higher Voltage Overhead Lines (IRAHVOL) |
| K. HOLMSEN | On His Own Behalf |
| B. CAMPBELL | On His Own Behalf |

## APPEARANCES

| | |
|---|---|
| J.B. Williston<br>E. Cheng<br>R.W. Rerie | Commission Staff |
| T.M. Berry<br>E. Switlishoff<br>R.V. Stubbings | Commission Consultants |
| Allwest Reporting Ltd. | Court Reporters |

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Transmission Corporation
Certificate of Public Convenience and Necessity Application for the
Vancouver Island Transmission Reinforcement Project

and

Sea Breeze Victoria Converter Corporation
Certificate of Public Convenience and Necessity Application for the
Vancouver Island Cable Project

## EXHIBIT LIST

| Exhibit No. | Description |
|---|---|
| *COMMISSION DOCUMENTS* | |
| A-1 | Commission letter dated July 12, 2005 and Order No. G-70-05 establishing the Procedural Conference |
| A-2 | Letter dated July 25, 2005 denying the IRAHVOL request for a delay of the Procedural Conference and advising that registrations for Intervenor and Interested Party status will be accepted until September 16, 2005 (Exhibit C3-4) |
| A-3 | Letter dated August 3, 2004 to Gary Holman, Salt Spring Regional District regarding Exhibits submitted under BCTC's Transmission System Capital Plan proceeding |
| A-4 | Letter and Commission Information Request No. 1 dated August 5, 2005 |
| A-5 | Letter dated August 8, 2005 to IRAHVOL regarding submission of Information Requests |
| A-6 | Letter dated August 9, 2005 and Order No. G-72-05 establishing a Pre-hearing Conference and Regulatory Timetable |
| A-7 | Letter dated August 11, 2005 responding to IRAHVOL's invitation to view a portion of the Tsawwassen corridor (Exhibit C3-10) |
| A-8 | Letter dated August 22, 2005 responding to Pamela Sutherland's invitation to view a portion of the Tsawwassen corridor (Exhibit C36-2) |

| Exhibit No. | Description |
|---|---|
| A-9 | Letter dated August 22, 2005 responding to Charles Bazzard's invitation to view a portion of the Salt Spring corridor (Exhibit C25-2) |
| A-10 | Letter dated August 22, 2005 responding to Julie Berks' invitation to view a portion of the Tsawwassen corridor (Exhibit C21-2) |
| A-11 | Letter dated August 29, 2005 commenting on the process for consideration of IRAHVOL's request that the zero rating of the HVDC system for planning purposes be included within the scope of the proceeding (Exhibit C3-12), and to identify the implications of the request for the regulatory process steps that are scheduled to occur prior to a decision regarding the IRAHVOL request |
| A-12 | Letter dated September 1, 2005 listing the proposed dates and locations for the Town Hall Meetings |
| A-13 | Letter and Commission Information Request No. 2 dated September 7, 2005 |
| A-14 | Letter dated September 9, 2005 requesting submissions on the Commission Panel's proposed plan for corridor inspections |
| A-15 | Letter dated September 20, 2005 to Karsten Holmsen - Request for extension denied |
| A-16 | Letter dated October 4, 2005 and Order No. G-96-05 issuing an amended Regulatory Timetable |
| A-17 | Letter No. L-87-05 dated October 12, 2005 amending a Revised Regulatory Timetable |
| A-18 | Letter dated October 18, 2005 denying Sea Breeze's request that the Commission require BCTC and any other participants who may wish to oppose the consolidation of the proceedings to review the VITR Application and the Vancouver Island Cable Project Application to file written argument (Exhibit C31-4) |
| A-19 | Letter dated October 19, 2005 issuing the Agenda for the Pre-hearing Conference |
| A-20 | Letter dated October 26,2005 – Information Request No. 1 to BC Hydro |
| A-21 | Letter dated October 26,2005 – Information Request No. 1 to IRAHVOL |
| A-22 | Letter dated October 26,2005 – Information Request No. 1 to Karsten Holmsen |

| Exhibit No. | Description |
|---|---|
| A-23 | Letter dated October 26,2005 – Information Request No. 1 to South Delta Secondary School Parent Advisory Council |
| A-24 | Letter dated October 26,2005 – Information Request No. 1 to Islands Trust |
| A-25 | Letter dated October 26,2005 – Information Request No. 1 to Sea Breeze Pacific Regional Transmission System, Inc. |
| A-26 | Letter dated October 26,2005 – Information Request No. 1 to Corporation of Delta |
| A-27 | Letter dated October 26,2005 – Information Request No. 1 to IRAHVOL |
| A-28 | Letter and Order G-109-05 dated October 27, 2005 – Revised Regulatory Timetable |
| A-29 | Letter dated November 3, 2005 to the Hul'qumi'num Treaty Group establishing a written comment process for the HTG requests and other submissions as set out in Exhibits C27-3, C27-5 and C27-7 |
| A-30 | Letter dated November 9, 2005 – 2 Issues at Pre-Hearing Conference |
| A-31 | Letter dated November 15, 2005 – Submission of Commission Counsel to Hul'qumi'num Treaty Group Submissions |
| A-32 | Letter dated November 15, 2005 – Consolidation of BCTC-VITR and Sea Breeze VIC Proceedings |
| A-33 | Letter dated October 6, 2005 enclosing Order No. G-97-05 and Notice of Pre-hearing Conference |
| | ***Previously A-1 in Sea Breeze VIC proceeding** |
| A-34 | Letter dated October 17, 2005 - Information Request No. 1 to Sea Breeze |
| | ***Previously A-2 in Sea Breeze VIC proceeding** |
| A-35 | Letter dated November 18, 2005 – Information Request No. 2 to Sea Breeze |
| A-36 | Letter dated November 18, 2005 to BCTC and Sea Breeze – Commission Panel scope decision addressing the IRAHVOL Complaint (Exhibit C3-21) discussed at the Pre-hearing Conference |
| A-37 | Commission Counsel letter dated November 25, 2005 re: Mikisew Cree First Nation Court of Appeal Decision |

| Exhibit No. | Description |
|---|---|
| A-38 | Letter dated November 25, 2005 to the Hul'qumi'num Treaty Group granting an extension of time for HTG to file a further reply submission addressing the BC Hydro Submission (Exhibit C6-5) |
| A-39 | Letter No. L-102-05 dated November 25, 2005 – Notice of Town Hall Meetings |
| A-40 | Letter No. L-103-05 dated December 1, 2005 - Commission Panel Decision regarding HTG's request for Advance Orders and other submissions as set out in Exhibits C27-3, C27-5, and C27-7 and issues a revised Regulatory Timetable |
| A-41 | Letter dated December 8, 2005 providing procedural information on the public hearing process to Participants |
| A-42 | Letter dated December 8, 2005 accepting Bonneville Power Administration request for Interested Party status and reassigning Exhibit E-19 as Exhibit D-71 |
| A-43 | Letter dated December 9, 2005 approving BCTC's request for an extension to the filing date for Intervenor Evidence |
| A-44 | Letter dated December 14, 2005 to Karsten Holmsen and John Cross responding to their requests for an extension to the time limit for presentations at the Town Hall Meetings |
| A-45 | Letter dated December 16, 2005 requesting Participants to comment on the proposed draft Revised Regulatory Timetable and notice that Exhibits B2-9 and B2-10 are withdrawn |
| A-46 | Letter dated December 20, 2005 responding to Karsten Holmsen's December 18, 2005 letter (Exhibit C1-20) requesting an opportunity for Intervenors to make presentations at Town Hall Meetings as well as in the Oral Hearing, in part, to provide supplemental information to the public that BCTC has not addressed |
| A-47 | Letter dated December 22, 2005 and Order No. G-141-05 issuing a Revised Regulatory Timetable and a revised Notice of Town Hall Meetings |
| A-48 | Letter dated January 5, 2006 to Maureen Broadfoot providing clarification of the purpose of the Town Hall Meetings |
| A-49 | Letter dated January 5, 2006 to Valerie Roddick providing clarification of the purpose of the Town Hall Meetings |

| Exhibit No. | Description |
|---|---|
| A-50 | Letter dated January 5, 2006 to Daria Zovi, IRAHVOL, clarifying the purpose of presentations at the Town Hall Meetings |
| A-51 | Letter dated January 5, 2006 to Hans Karow, CORE, advising that the deadline for filing evidence had passed and that the book noted in Exhibit C46-8 would not be accepted as evidence |
| A-52 | Letter dated January 9, 2006 issuing Commission Information Request No. 1 to the City of White Rock |
| A-53 | Letter dated January 9, 2006 issuing Commission Information Request No. 3 to British Columbia Transmission Corporation |
| A-54 | Letter dated January 9, 2006 issuing Commission Information Request No. 3 to IRAHVOL |
| A-55 | Letter dated January 9, 2006 issuing Commission Information Request No. 1 to Islands Trust |
| A-56 | Letter dated January 19, 2006 Commission Information Request No. 4 to British Columbia Transmission Corporation |
| A-57 | Letter to Hans Karow regarding emails to Chair and Panel Members |
| A-58 | Letter to Intervenors confirming the details of the Opening Oral Submissions, the Proponent Consolidation of the Hearing Issues List and the Date and Location of Oral Hearing |
| A-59 | Letter dated January 19, 2006 Commission Information Request No. 3 to Sea Breeze Victoria Converter Corporation |
| A-60 | Letter dated January 20, 2006 asking Sea Breeze to respond to a customer inquiry from Lynne Schroder (Exhibit E-73) |
| A-61 | Letter dated January 24, 2006 responding to Mr. Holmsen's questions regarding the hearing process (Exhibit C1-22) |
| A-62 | Letter dated January 24, 2006 to Participants enclosing the Order of Appearances for the Opening Oral Submissions session scheduled for January 30, 2006 and requesting Participants to advise Commission Counsel of their intention to make an Opening Statement |
| A-63 | Letter dated January 25, 2006 to the City of White Rock granting Leave to file the Council Resolution as evidence with respect to the Sea Breeze VIC (Exhibit 57-4) |

| Exhibit No. | Description |
|---|---|
| A-64 | Letter dated January 26, 2006 and Commission Staff Issues List |
| A-65 | Letter dated January 27, 2006 advising participants that the Commission Panel will release a Hearing Issues List based on the issues raised during the Oral Submissions on January 30, 2006 |
| A-66 | Letter dated February 1, 2006 on the Orders of Cross-examination for BCTC Panels 1, 2, and 3 |
| A-67 | Letter dated February 1, 2006 to BCTC with Commission Information Request No. 5 |
| A-68 | Letter dated February 2, 2006 from BCUC’s Counsel responding to K. Holmsen inquiries on the Order of Cross-Examination for BCTC’s Witness Panels (Exhibit C1-32) |
| A-69 | Letter dated February 3, 2006 with Commission Information Request No. 6 to BCTC regarding Exhibit B1-44 to BCUC IR 3.179.1 |
| A-70 | Letter dated February 3, 2006 enclosing the Hearing Issues List for the VITR-VIC Public Hearing |
| A-71 | Submission at Public Hearing – Revised Hearing Issues List |
| A-72 | Letter dated March 27, 2006 responding to Christopher Bystrom of Fasken Martineau DuMoulin regarding his request to strike Evidence from the Record |
| A-73 | Letter dated April 3, 2006 to Seabreeze requesting response to BC Hydro’s request (Exhibit C6-28) for an Order striking most of Sea Breeze's Response to Undertakings to BC Hydro at Transcript Volume 33, pages 6261-6262 |
| A-74 | Letter dated April 4, 2006 to participants requesting responses to BCTC’s request to change the Argument filing schedule |
| A-75 | Letter dated April 4, 2006 approving BC Hydro's request (Exhibit C31-57) to strike a portion of Sea Breeze's Response to Undertakings to BC Hydro at Transcript Volume 33, pages 6261-6262 |
| A-76 | Letter dated April 7, 2006 to participants amending the Argument filing dates and Evidentiary schedule |
| A-77 | Letter dated May 24, 2006 confirming Oral Phase of Argument to take place on May 30, 2006 |

| Exhibit No. | Description |
|---|---|
| A-78 | Letter dated May 26, 2005 issuing the Oral Argument Issues List |

### COMMISSION COUNSEL DOCUMENTS

| | |
|---|---|
| A2-1 | Report and Recommendations of the Public Inquiry in the Matter of Complaints against British Columbia Hydro and Power Authority and its proposed 230 kV transmission Line from Dunsmuir to Gold River, dated July 26, 1989 |
| A2-2 | Inquiry Report Commission Decision and Exhibit A-22 on the Inquiry relating to the Undergrounding of the Overhead Transmission Lines along Boundary Road in the City of Vancouver dated May 26, 1995 |
| A2-3 | Inquiry Report in the Matter of West Kootenay Power Limited and the Routing of Line Number 49 in the Vicinity of Penticton, B dated January 14, 1998 |
| A2-4 | Commission Decision in the Matter of West Kootenay Power Limited Certificate of Public Convenience and Necessity for Line Number 44, dated August 5th, 1998 |
| A2-5 | British Columbia Utilities Commission Decision in the Matter of West Kootenay Power Limited, Certificate of Public Convenience and Necessity for the Kootenay 230 kV System Development Project dated June 5, 2000 |
| A2-6 | Commission Letter No. L-31-01 with attached Reasons for Decision dated October 25, 2001 relating to the Complaint on the Routing of the 230 kV Transmission Lines through the Ootschenia area |
| A2-7 | Commission Letter No. L-34-02 dated September 6, 2002 in the matter of the Aquila Networks Canada (British Columbia) Ltd. and the Application for Reconsideration of Commission Decision and Order No. G-46-01 |
| A2-8 | Extracts from Special Direction, HC-1 and HC-2 |
| A2-9 | Submission at Public Hearing -Excerpt, Headed “1.4 The Nature of Commission Approvals”, Page 2 |
| A2-10 | Submission at Public Hearing – Principles of Corporate Finance, the First Canadian Edition |
| A2-11 | Submission at Public Hearing – Page from Spreadsheet in Exhibit B1-44 |

| Exhibit No. | Description |
|---|---|
| *BCTC DOCUMENTS* | |
| B1-1 | **BRITISH COLUMBIA TRANSMISSION CORPORATION** letter dated July 7, 2005 and Certificate of Public Convenience and Necessity Application for the Vancouver Island Transmission Reinforcement Project |
| B1-2 | Letter dated July 12, 2005 providing amendments to the July 7, 2005 CPCN application for the Vancouver Island Transmission Reinforcement Project |
| B1-3 | Letter dated July 26, 2005 responding to the IRAHVOL letter of July 23, 2005 (Exhibit C3-4) |
| B1-4 | Letter dated July 29, 2005 advising that BCTC will address the Salt Spring Regional District's Transmission System Capital Plan (VITR Exhibits C2-2 and C2-3) during the VITR proceeding |
| B1-5 | Letter dated August 18, 2005 to Neil Atchinson and Cecil Dunn, IRAHVOL, regarding Minister Neufeld's letter of July 29 and responding to questions raised by IRAHVOL regarding the Vancouver Island Transmission Reinforcement Project |
| B1-6 | Letter dated August 29, 2005 filing Responses (Volumes 1, 2 and 3) to Commission Information Request No. 1 |
| B1-7 | Letter dated August 31, 2005 filing amendments to the July 7, 2005 Certificate of Public Convenience and Necessity Application for the Vancouver Island Transmission Reinforcement Project |
| B1-8 | Letter dated September 13, 2005 response regarding proposed inspection |
| B1-9 | Response dated September 22, 2005 regarding Karsten Holmsen's late Information Request |
| B1-10 | Letter dated September 27, 2005 unable to file IR Responses today |
| B1-11 | Letter dated September 27, 2005 – Partial set of Responses to BCUC IR No. 2 and Intervenor IR No. 1 |
| B1-12 | Letter dated September 28, 2005 – Revised response to BCUC IR No. 1.110.1 |

| Exhibit No. | Description |
|---|---|
| B1-13 | Letter dated September 28, 2005 – Revised Tables in Information Requests |
| B1-14 | Letter dated September 30, 2005 – Information Request Extension Clarification |
| B1-15 | E-mail dated October 4, 2005 to Karsten Holmsen regarding the distribution of the IR-2 responses |
| B1-16 | Letter dated October 7, 2005 responding to Exhibits A-6, A-11 and B-15 |
| B1-17 | Letter dated October 11, 2005 filing second instalment of Information Responses to Commission IR-2 and Intervenor IRs-1 |
| B1-18 | Letter dated October 14, 2005 filing the final instalment of Information Responses to Commission IR-2 and Intervenor IRs-1 |
| B1-19 | Letter dated October 21, 2005 filing responses to Late Information Requests from Maureen Broadfoot; Glen Page; and Karsten Holmsen |
| B1-20 | Letter dated October 26, 2005 – Information Request to Corporation of the City of Delta |
| B1-21 | Letter dated October 26, 2005 – Information Request to IRAHVOL |
| B1-22 | Letter dated October 26, 2005 – Information Request to Karsten Holmsen |
| B1-23 | Letter dated October 26, 2005 – Information Request to Pam Sutherland |
| B1-24 | Letter dated October 26, 2005 – Information Request to SDSSPAC |
| B1-25 | Letter dated October 26, 2005 – Information Request to Maracaibo Estates Ltd. |
| B1-26 | Letter dated October 26, 2005 – Information Request to IRAHVOL |
| B1-27 | Letter dated October 26, 2005 – Information Request to Sea Breeze |

| Exhibit No. | Description |
|---|---|
| B1-28 | Letter dated October 26, 2005 – Information Request to J. Truscott |
| B1-29 | Letter dated October 26,2005 – Information Request to Islands Trust |
| B1-30 | Letter dated November 8, 2005 – Amendment to Application |
| B1-31 | Letter dated November 15, 2005 – Response to Hul’qumi’num Treaty Group Information Request |
| B1-32 | **BRITISH COLUMBIA TRANSMISSION CORPORATION** – Letter dated October 18, 2005 requesting Intervenor Status |
| | ***Previously C9-1 in Sea Breeze VIC proceeding** |
| B1-33 | Information Request No. 1 dated November 18, 2005 to Sea Breeze regarding the Vancouver Island Cable Project |
| B1-34 | Revised Information Request Questions 45 & 46 dated November 21, 2005 to Sea Breeze regarding the Vancouver Island Cable Project |
| B1-35 | Facsimile dated December 9, 2005 – Regarding filing of Intervenor Evidence |
| B1-36 | Letter dated December 15, 2005 requesting a further extension to the filing of Intervenor Evidence |
| B1-37 | Letter dated December 16, 2005 filing a report on the potential effect on property values of the VITR Project prepared by Larry Dybvig of Grover, Elliot & Co. Ltd. and the response of Dr. Linda Erdreich of Exponent to the evidence of Dr. Havas on the health effects associated with electromagnetic fields |
| B1-38 | Letter dated December 20, 2005 commenting on the draft revised proceeding timetable |
| B1-39 | Letter dated December 21, 2005 filing BCTC’s Intervenor Evidence regarding Sea Breeze’s VIC |
| B1-40 | Letter dated January 3, 2006 filing supporting documentation to the Rebuttal Evidence of Linda Erdreich contained in Exhibit B1-37 |
| B1-41 | Information Request No. 1 to the City of White Rock dated January 9, 2006 regarding the VIC |

| Exhibit No. | Description |
|---|---|
| B1-42 | Letter dated January 10, 2006 from the Environmental Assessment Office (on behalf of BCTC) filing a copy of the environmental assessment procedural order for the VITR project |
| B1-43 | Letter dated January 18, 2006 from Marcel Reghelini filing BCTC's witness panels |
| B1-44 | Letter dated January 23, 2006 filing partial responses to Information Requests on Exhibit B1-39 (BCTC Intervenor Evidence on VIC) – Part I |
| B1-45 | Letter dated January 24, 2006 responding to Maureen Broadfoot's concerns regarding the project description document on BCTC's website |
| B1-46 | Letter dated January 26, 2006 responding to Karsten Holmsen's request and BCTC's decision that Mr. Gallagher will not appear as a witness |
| B1-47 | Letter dated January 25, 2006 filing remainder of responses to Information Requests on Exhibit B1-39 (BCTC Intervenor Evidence on VIC) - Part 2 |
| B1-48 | Letter dated January 26, 2006 advising that the EMF Witness Panel may not be able to proceed until later in the hearing due to the availability of Mr. Dybvig and Mr. Havas |
| B1-49 | Letter dated January 29, 2006 filing remainder of responses to Information Requests on Exhibit B1-39 (BCTC Intervenor Evidence on VIC) – Part 3 |
| B1-50 | Opening Statement of Mr. Carpenter |
| B1-51 | Letter dated January 27, 2006 responding to Karsten Holmsen's request and BCTC's decision that Ms. Peverett will not appear as a witness |
| B1-52 | Letter dated January 31, 2006 filing BCTC's Information Request to Karsten Holmsen's regarding Exhibit C1-25 |
| B1-53 | Letter dated February 1, 2006 filing BCTC's consolidated issues list presented to the Commission Panel on February 1, 2006 |
| B1-54 | Letter dated February 1, 2006 response to BCUC Information Request No. 4 plus a guideline that identifies the Exhibit in which each of the BCTC Information Requests responses was filed |
| B1-55 | Letter dated February 3, 2006 with Witness Panel Qualifications with correction to titles of witnesses attached re: Exhibit B1-43 |

| Exhibit No. | Description |
|---|---|
| B1-56 | Letter dated February 3, 2006 filing revisions to the following BCUC and Sea Breeze Information Responses<br>• BCUC IR 1.3.7<br>• BCUC IR 1.36.1<br>• BCUC IR 1.91.1<br>• BCUC IR 3.178.5<br>• BCUC IR 3.181.4<br>• BCUC IR 3.184.3<br>• BCUC IR 3.191.1<br>• Sea Breeze IR 2.4.1<br>• Sea Breeze IR 2.13.2<br>• Sea Breeze IR 2.65.1 |
| B1-57 | British Columbia Transmission Corporation filing of Archaeological Assessments, Test Hole Data, and Transcript of Tsawwassen Information Session, dated February 6, 2006 |
| B1-58 | Direct Evidence of Don Gamble |
| B1-59 | Group of Revised Information Requests |
| B1-60 | Response to Undertaking at Transcript Volume 8, Page 1162 Line 24 to Page 1163 Line 9 |
| B1-61 | Response to BCUC's Information Request No. 5.205.1, 5.205.2, 5.205.3 and 6.206.0 |
| B1-62 | Transcript Errata for the Community Information Session on Tuesday, May 31, 2005 |
| B1-63 | "Vancouver Island 230 KV Transmission Reinforcement Project, Hwy #17 to English Bluff Area Restoration Cost Assessment" |
| B1-64 | "VITR Incentive / Penalty Mechanism" |
| B1-65 | Expected Energy Not Served (EENS) Study For Vancouver Island Transmission Reinforcement Project (Part IV) - Dated January 9, 2006 |
| B1-66 | Revised "Non-Natural Marine Hazards Assessment – February 14, 2006 |

| Exhibit No. | Description |
|---|---|
| B1-67 | Submission at Public Hearing - Vancouver Island Transmission Reinforcement (VITR) Project, Comparison of Suggested Route Alternatives at Tsawwassen – Revised February 14, 2006 |
| B1-68 | Submission at Public Hearing - “Non-Financial Ranking of Project Alternatives – Tsawwassen” BCUC Information Request 4.204.0, Revised Response Issued February 15, 2006 |
| B1-69 | Submission at Public Hearing – Undertaking of Mr. Barrett, BCTC to Mr. Austin, IRAHVOL |
| B1-70 | Submission at Public Hearing – Memorandum from Christopher Bystrom of Fasken Martineau |
| B1-71 | Submission at Public Hearing – Response to Information Request, Volume 17, Pages 2895-2896 and 2898-2899 |
| B1-72 | Submission at Public Hearing – VI Transmission Reinforcement Project team organization chart |
| B1-73 | Submission at Public Hearing – Undertaking of Mr. Dunne, BCTC to Mr. Holmsen |
| B1-74 | Submission at Public Hearing – Undertaking of Mr. MacPhail, BCTC, to Mr. Landy, Sea Breeze |
| B1-74A | Submission at Public Hearing – Transcript, Vol. 18, Page 3238, Line 12 to Page 3239, Line 9 |
| B1-75 | Submission at Public Hearing – Draft Report on Geotechnical Stability Assessment |
| B1-76 | Submission at Public Hearing – Documents received from Mr. Carpenter |
| B1-77 | Submission at Public Hearing – Graph, EMF Levels measured at ground level |
| B1-78 | Submission at Public Hearing – NERC Standard |
| B1-79 | Submission at Public Hearing – Revised Monte Carlo Analysis Summary Table |
| B1-80 | Submission at Public Hearing – Seismic Review of Galiano Island, Parker Island and Salt Spring Island Cable Terminal Sites |

| Exhibit No. | Description |
|---|---|
| B1-81 | Submission at Public Hearing – Official Community Plan of Salt Spring Island |
| B1-82 | Submission at Public Hearing – Group of documents from the Corporation of Delta |
| B1-83 | Submission at Public Hearing – Undertaking of BCTC to Ms. Kudzin |
| B1-84 | Submission at Public Hearing – Undertaking of Mr. Barrett to Mr. Arvay |
| B1-85 | Submission at Public Hearing – Probability distribution in figure-related conceptual form |
| B1-86 | Submission at Public Hearing – 1958 aerial photograph of Delta |
| B1-87 | Submission at Public Hearing – 2005 aerial photograph – Not available in electronic copy, only available at BCUC's Resource Library, due to size of map |
| B1-88 | Submission at Public Hearing – Map of the B.C. transmission system - Not available in electronic copy, only available at BCUC's Resource Library, due to size of map |
| B1-89 | Submission at Public Hearing – Tsawwassen First Nation Agreement in principle |
| B1-90 | Submission at Public Hearing – Corporation of Delta, Minutes of Regular Meeting of July 10, 2001 |
| B1-91 | Submission at Public Hearing – Document headed "May 16, 2001 – Risk of Undersea Slides Threaten Delta's Foreshore", to Mayor and Council from the Environmental Advisory Committee |
| B1-92 | Submission at Public Hearing – "Volume 15, No. 2, 2004, Documents of the NRPB, Advise on Limiting Exposure to Electromagnetic Fields (0-300 GHZ) |
| B1-93 | Submission at Public Hearing – Printout from World Health Organization website, "Electromagnetic Fields (EMF)" |
| B1-94 | Submission at Public Hearing – Response to Information Request at Volume 20, Page 3849 |

| Exhibit No. | Description |
|---|---|
| B1-95 | Submission at Public Hearing – Response to Information Request at Volume 20, Page 3634 |
| B1-96 | Submission at Public Hearing – Material from TRAHVOL's website |
| B1-97 | Submission at Public Hearing – Undertaking of BCTC to Mr. Herbert, Sea Breeze |
| B1-98 | Undertaking of BCTC to Commissioner Hobbs at Transcipt Volume 21, Page 3856, Lines 14 to 19 |
| B1-99 | Undertaking of Mr. Barrett, BCTC to Commissioner Nicholls at Transcipt Volume 19, Page 3477. Line 22, to Page 3478, line 2 |
| B1-100 | Undertaking of Mr. McPhail, BCTC to Mr. Fulton, BCUC Counsel at Transcipt Volume 19, Page 3429, Lines 10 to 17 |
| B1-101 | Submission at Public Hearing – Undertaking of BCTC to Commissioner O'Hara [Nicholls] |
| B1-102 | Submission at Public Hearing – Letter from Chair of Manitoba Clean Environment Commission dated September 21, 2001 |
| B1-103 | Submission at Public Hearing – National Energy Board's Environmental Screening Report on the Sumas 2 Hearing, with the Boards' comments on the EMF issue |
| B1-104 | Submission at Public Hearing – Letter from United States Environmental Protection Agency dated January 29th, 1992 with respect to potential carcinogenicity of Electromagnetic Fields |
| B1-105 | Submission at Public Hearing – Article entitled "Electromagnetic Hypersensitivity, A Systematic Review of Provocation Studies" by Dr. James Rubin and two co-authors |
| B1-106 | Submission at Public Hearing – World Health Organization Fact Sheet dated December 2005, headed "Electromagnetic Fields and Public Health, Electromagnetic Hypersensitivity" |
| B1-107 | Submission at Public Hearing – Study from UK Health Protection Agency Entitled "Power Frequency Electromagnetic Fields, Melatonin and the risk of Breast Cancer, Report of an Independent Advisory Group on Non-ionizing Radiation" |

| Exhibit No. | Description |
|---|---|
| B1-108 | Submission at Public Hearing – Paper entitled “Childhood Cancer in Relation to Distance from High Voltage Power Lines in England and Wales: A Case-Controlled Study” by Draper et al |
| B1-109 | Submission at Public Hearing – Document entitled “Framework Guiding Public Health Policy, Options and Areas of Scientific Uncertainty Dealing with EMF”, dated June 2005 |
| B1-110 | Submission at Public Hearing – Undertaking of Mr. Gabel, BCTC, to Commissioner Hobbs |
| B1-111 | Submission at Public Hearing – Undertaking of Mr. Barrett, BCTC to Commissioner O’Hara |
| B1-112 | Submission at Public Hearing – Undertaking of Mr. Barrett, BCTC, to Mr. Yarley, Delta |
| B1-113 | Submission at Public Hearing – Spreadsheet with planning level estimates highlighted |
| B1-114 | Submission at Public Hearing – Undertaking of Mr. Gabel, BCTC, to Commissioner Hobbs |
| B1-115 | Submission at Public Hearing – BCTC Sea Breeze Panel 1 documents |
| B1-116 | Submission at Public Hearing – Sea Breeze’s responses to NEB’s first round of Information Requests in NEB Hearing |
| B1-117R | Submission at Public Hearing – Letter from Sea Breeze to Rob Pellatt of BCTC dated November 25, 2004 |
| B1-118 | Submission at Public Hearing – Sea Breeze Power Corp. News Release dated September 16, 2005 |
| B1-119 | Submission at Public Hearing – Undertaking of Mr. Gabel, BCTC to Commissioner Hobbs |
| B1-120 | Submission at Public Hearing – Undertaking of BCTC to Mr. Austin, IRAHVOL |
| B1-121 | Submission at Public Hearing – Undertaking of Mr. Barnett, BCTC to Mr. Landy, Sea Breeze |

| Exhibit No. | Description |
|---|---|
| B1-122 | Submission at Public Hearing – BCTC Transmission Corporation Results for VITR Voltage Studies |
| B1-123 | Submission at Public Hearing – Letter identifying BCTC's Witness Panel |
| B1-124 | Submission at Public Hearing – Undertaking of BCTC to Mr. Herbert, Sea Breeze |
| B1-125 | Submission at Public Hearing – Undertaking of BCTC to Karsten Holmsen |
| B1-126 | Submission at Public Hearing – Undertaking of BCTC to Karsten Holmsen |
| B1-127 | Submission at Public Hearing – Letter from Esquimalt First Nation to National Energy Board dated March 13, 2006 |
| B1-128 | Submission at Public Hearing – Letter from MacLeod Dixon dated December 20, 2002, with attached Report from Jacques Whitford & Associates |
| B1-129 | Submission at Public Hearing – Figure 4A, Boomer Seismic Profiles across the southern Roberts Bank Delta Front |
| B1-130 | Submission at Public Hearing – Two pages re: BC Hydro 230 KV Corridor Southern Straight of Georgia, Stage 1 Marine Geologic Hazards |
| B1-131 | Submission at Public Hearing – "The Columbia River Treaty Entity Agreement, Aspects of the Delivery of the Canadian Entitlement" |
| B1-132 | Submission at Public Hearing – Letter to Board of Governors, California Independent System Operator dated September 1, 2006 |
| B1-133 | Submission at Public Hearing – Geotechnical Input to the Seismic Vulnerability Assessment of the City of Surrey Sanitary Sewer System |
| B1-134 | Letter dated April 12, 2006 filing responses to outstanding Undertakings |
| B1-135 | Letter dated May 4, 2006 filing a report described by Mr. Nelson at Transcript 37, pages 7238-7246, given during the evidentiary phase |

| Exhibit No. | Description |
|---|---|

*SEA BREEZE DOCUMENTS (SEE ALSO SEA BREEZE EXHIBITS C31)*

B2-1 September 30, 2005 Letter and Application for Vancouver Island Cable Project

***Previously B-1 in Sea Breeze VIC proceeding**

B2-2 Letter dated October 12, 2005 – Confirmation of filing requirements by P. John Landry, Davis & Company

***Previously B-2 in Sea Breeze VIC proceeding**

B2-3 Letter dated October 14, 2005 – Notice of Assignment

***Previously B-3 in Sea Breeze VIC proceeding**

B2-4 Letter dated October 17, 2005 – Detailed Written Submission to be filed October 18, 2005

***Previously B-4 in Sea Breeze VIC proceeding**

B2-5 Letter dated October 18, 2005 – Consolidation Application and Proposed Timetable

***Previously B-5 in Sea Breeze VIC proceeding**

B2-6 Letter dated October 20, 2005 – Authorities referred to in Exhibit B-5

***Previously B-6 in Sea Breeze VIC proceeding**

B2-7 Letter dated October 20, 2005 – Draft Terms of Reference

***Previously B-7 in Sea Breeze VIC proceeding**

B2-8 E-mail dated November 7, 2005 – Response to Commission Information Request No. 1 regarding the VIC

***Previously B-8 in Sea Breeze VIC proceeding**

B2-9 **WITHDRAWN**
**CONFIDENTIAL** -- Letter dated November 7, 2005 – Response to Commission Information Request

***Previously B-9 in Sea Breeze VIC proceeding**

| Exhibit No. | Description |
|---|---|
| B2-10 | **WITHDRAWN**<br>CONFIDENTIAL -- Facsimile dated November 9, 2005 – Response to Commission Information Request No. 1.8.2<br><br>***Previously B-10 in Sea Breeze VIC proceeding** |
| B2-11 | Letter dated November 17, 2005 – Responses to BCTC Information Request No. 1 |
| B2-12 | Letter dated November 18, 2005 – Outstanding responses to Commission Information Request No. 1 regarding VIC |
| B2-13 | Letter dated November 18, 2005 filing outstanding responses to Commission Information Request No. 1 regarding the Sea Breeze Intervenor Evidence on VITR ($2^{nd}$ instalment) |
| B2-14 | Letter dated November 29, 2005 – Response to Commission Information Request No. 1.7.2 |
| B2-15 | Letter dated November 29, 2005 – Revised response to Commission Information Request No. 1.76.2 |
| B2-16 | Letter dated December 6, 2005 – Dispute Exhibit E-19 Letter of Comment |
| B2-17 | Letter dated December 6, 2005 – Response to Commission Information Request No. 2 |
| B2-18 | Letter dated December 6, 2005 – Supplemental Information to Commission Information Requests No. 1.17.1 and 1.25.1 |
| B2-19 | Letter dated December 7, 2005 – Response to BC Hydro Information Request No. 1 |
| B2-20 | Letter dated December 7, 2005 – Responses to BCTC Information Request No. 1 |
| B2-21 | Letter dated December 8, 2005 – Additional responses to BCTC Information Request No. 1 |
| B2-22 | Letter dated December 9, 2005 commenting on BCTC's request for an extension of time for the filing of Intervenor Evidence related to the VIC |
| B2-23 | Letter dated December 9, 2005 enclosing a copy of the Sea Breeze response to BCTC's December 8, 2005 request for a copy of the VIC studies |

| Exhibit No. | Description |
|---|---|
| B2-24 | Letter dated December 9, 2005 filing outstanding responses to BCTC IR-1 regarding the VIC |
| B2-25 | Letter dated December 12, 2005 filing outstanding responses to Commission Information Request No. 2 regarding the VIC |
| B2-26 | Letter dated December 12, 2005 filing outstanding responses to BCTC IR-1 regarding Sea Breeze Intervenor Evidence on VITR |
| B2-27 | Letter dated December 12, 2005 filing outstanding responses to BC Hydro IR-1 regarding the VIC |
| B2-28 | Letter dated December 12, 2005 filing outstanding responses (3rd installment) to BCTC IR-1 regarding the VIC |
| B2-29 | Letter dated December 13, 2005 filing outstanding responses (4th installment) to BCTC IR-1 regarding the VIC |
| B2-30 | Letter dated December 13, 2005 filing outstanding response to BCUC IR 1.56.1 |
| B2-31 | Letter dated December 14, 2005 filing outstanding responses (5th installment) to BCTC IR-1 regarding the VIC |
| B2-32 | Letter dated December 14, 2005 filing outstanding responses (Final installment) to BCTC IR-1 regarding Intervenor Evidence relating to the VITR |
| B2-33 | Letter dated December 15, 2005 filing outstanding responses (Final installment) to BCTC IR-1 regarding the VIC |
| B2-34 | Letter dated December 15, 2005 responding to BCTC's request for a further extension to the filing date for Intervenor Evidence (Exhibit B1-36) |
| B2-35 | Letter dated December 16, 2005 filing outstanding responses (Final installment) to BCUC IR-2 regarding the VIC |
| B2-36 | Letter dated December 20, 2005 supporting the draft Revised Regulatory Timetable |
| B2-37 | Letter dated January 4, 2006 filing responses to BCTC Information Requests 1.21.2, 1.21.3, 1.24.9 and 1.24.11 regarding Sea Breeze's Intervenor Evidence with respect to the VITR Application that were inadvertently omitted from the responses to BCTC IR No. 1 (VITR) that were filed with the Commission in Exhibits B2-11, B2-20, B2-26 and B2-32 |

| Exhibit No. | Description |
|---|---|
| B2-38 | Letter dated January 9, 2006 issuing Information Request No. 1 to BCTC regarding its Intervenor Evidence on the VIC |
| B2-39 | Letter dated January 11, 2006 listing corrections to Sea Breeze's Information Request No. 1 to the British Columbia Transmission Corporation regarding its Intervenor Evidence in the VIC (Exhibit B2-38) |
| B2-40 | Email response dated January 9, 2006 to Letter of Comment dated January 8, 2006 from Derek & Karen Lorimer |
| B2-41 | Letter dated January 25, 2006 to the Fraser River Estuary Management Program (FREMP) requesting they clarify the role they expect to play in the review by the Environmental Assessment Office |
| B2-42 | Letter dated January 25, 2006 proposing an amendment to the Order of Testimony of BCTC's Witness Panels (Exhibit A-41) |
| B2-43 | Letter dated January 25, 2006 responding to a Letter of Comment from Lynne Schroder's concern on two property lots being affected and requesting clarification (Exhibit E-73) |
| B2-44 | Letter dated January 26, 2006 responding to a Letter of Comment from Gordon Hammond, Chair of the White Rock Ratepayers Association (Exhibit E-46) |
| B2-45 | Sea Breeze Opening Statement |
| B2-46 | Letter dated January 31, 2006 from Davis & Company responding to comments made during Opening Oral Submissions (Transcript Vol. 6, pp. 782-788) regarding VITR Related Issues identified by Sea Breeze |
| B2-47 | Letter dated February 1, 2006 from Davis & Company referring to Exhibit B2-46 and enclosing Sea Breeze's consolidation of the hearing issues list to the VIC Application |
| B2-48 | Letter dated February 1, 2006 responding to BCUC's Information Request No. 3 (Exhibit A-59) re: VIC-VITR Financial Analysis and spreadsheet |
| B2-49 | Letter dated February 1, 2006 responding to BCUC's Information Request No. 3 (Exhibit A-59) re: Guide to Sea Breeze VCC's Response to Information Requests |
| B2-50 | Letter dated February 3, 2006 filing supplemental responses to BCTC Information Requests |

| Exhibit No. | Description |
|---|---|
| B2-51 | Letter dated February 3, 2006 filing a list of witnesses, witness panels and CVs for each witness |
| B2-52 | Exhibits for Cross-Examination of BCTC Panel 1 |
| B2-53 | Copy of Dr. Rashwan’s Business Card |
| B2-54 | Submission at Public Hearing – Copy of two page letter from Mr. Manson to Ms. Peverett, Dated January 5, 2006 |
| B2-55 | Submission at Public Hearing - Email Between Ms. Peverett and Mr. Manson |
| B2-56 | Submission at Public Hearing – Extract from BCUC Information Request 140.1 |
| B2-57 | Submission at Public Hearing – Request for Information, Vancouver Island 230- KVAC Supply Submarine Cable System |
| B2-58 | Submission at Public Hearing – Volume 1 of 3, Tender Document, January 2006, Contract No. 300094 |
| B2-58A | Submission at Public Hearing – Exhibit B2-58 Remarked as Exhibit B2-58A |
| B2-58B | Submission at Public Hearing – Volume 2 of Tender documents |
| B2-58C | Submission at Public Hearing – Volume 3 of Tender documents |
| B2-59 | Submission at Public Hearing – Page 9i from Part 9, Appendix A |
| B2-60 | Submission at Public Hearing – Documents received from Mr. Landry |
| B2-61 | Submission at Public Hearing – Map relating to Lower Mainland and seismic sensitivity |
| B2-62 | Submission at Public Hearing – Sea Breeze Rebuttal Evidence |
| B2-63 | Submission at Public Hearing – Evidence “Reasons Why Sea Breeze Believes Bids Under…” |
| B2-64 | Submission at Public Hearing – Sea Breeze Omnibus document |
| B2-65 | Submission at Public Hearing – Excerpt from an article Re: Cone Penetration in Geotechnical Practice |

| Exhibit No. | Description |
|---|---|
| B2-66 | Submission at Public Hearing – Article by Robertson and Write on evaluating cyclic liquefaction potential using the cone penetration test |
| B2-67 | Submission at Public Hearing – Responses to Information Requests from BC Hydro |
| B2-68 | Submission at Public Hearing – Direct Evidence of Sea Breeze Panel 1 |
| B2-69 | Submission at Public Hearing – Opening Statement of Sea Breeze Corporate Policy / Management Panel |

### INTERVENOR DOCUMENTS

| | |
|---|---|
| C1-1 | **KARSTEN HOLMSEN** – Notice of Intervention dated May 15, 2005 |
| C1-2 | Letter dated July 27, 2005 outlining intervention issues for K. Holmsen |
| C1-3 | E-mail dated August 18, 2005 regarding the proposed site visits and requesting that the Panel remember to familiarize themselves with some of the alternative routes proposed to bypass the residential areas of Ladner and South Delta |
| C1-4 | Letter and Information Request No. 1 dated September 7, 2005 |
| C1-5 | E-mail dated September 10, 2005 support inspection |
| C1-6 | E-Mail dated September 15, 2005 requesting Procedure Clarification |
| C1-7 | E-mail dated September 20, 2005 confirming Procedure Clarification |
| C1-8 | E-mail dated September 21, 2005 – Supplemental Information Request |
| C1-9 | E-mail dated September 23, 2005 – Supplemental Information Request No. 2 |
| C1-10 | E-mail dated September 24, 2005 – Supplemental Information Request No. 3 |
| C1-11 | E-mail dated September 28, 2005 – Outstanding Questions in BCTC IR Responses |
| C1-12 | Letter dated October 3, 2005 regarding BCTC's CD Rom containing information responding to Information Requests |

| Exhibit No. | Description |
|---|---|
| C1-13 | Letter dated October 19, 2005 – Intervenor Evidence |
| C1-14 | Letter dated October 20, 2005 – Request Panel to reconsider viewing of Right-of-Ways |
| C1-15 | Letter dated October 26, 2005 – Corrections to Exhibit C1-14 |
| C1-16 | E-mail dated November 10, 2005 – Response to Commission Information Request No. 1 |
| C1-17 | E-mail dated November 10, 2005 – Response to BCTC Information Request No. 1 |
| C1-18 | Letter dated December 4, 2005 stating concerns regarding BCTC's Terms of Reference |
| C1-19 | Letter dated December 11, 2005 commenting on the time limit for presentations to be given at the Town Hall meetings |
| C1-20 | Letter dated December 18, 2005 responding to the Commission's letter of December 14, 2005 (Exhibit A-44) and requesting the Commission Chair to retract the changes to Exhibit A-41, indicated in Exhibit A-44, and allow Intervenor presentations at the Town Hall meetings as well as in the Oral Public Hearing processes |
| C1-21 | Letter dated January 13, 2006 withdrawing his request to make a presentation at the January 14, 2005 Town Hall Meeting in Tsawwassen |
| C1-22 | Letter dated January 22, 2006 requesting clarification on Oral Public Hearing Process |
| C1-23 | Letter dated January 24, 2006 requesting BCTC to include Mr. Richard Gallagher, Epidemiologist, Department Head, BC Cancer Research Centre, on the BCTC Witness Panel No. 4 and enclosing an excerpt from the 1998 West Kootenay Power CPCN Transcript |
| C1-24 | Letter dated January 24, 2006 requesting BCUC to include Ms. Jane Peverett, President and CEO on BCTC's Witness Panel # 1 or # 2, and be called to testify at the BCUC Oral Public Hearings to clarify previous statements with attached transcripts |
| C1-25 | Letter dated January 26, 2006 filing supplemental evidence under Exhibit C1-13, Section 1.0 on the effect of property values |
| C1-26 | Letter dated January 27, 2006 filing Opening Statement |

| Exhibit No. | Description |
|---|---|
| C1-27 | Letter dated January 27, 2006 responding to BCTC's response (Exhibit B1-46) and requesting Mr. Richard Gallagher be served a subpoena to appear as a witness at the Oral Public Hearing |
| C1-28 | Letter dated January 27, 2006 responding to BCTC's response (Exhibit B1-51) and requesting Jane Peverett be served a subpoena to appear as a witness at the Oral Public Hearing |
| C1-29 | Letter dated February 1, 2006 with Excel attachments in response to BCTC's Information Request No. 14 regarding Exhibit C1-25 |
| C1-30 | Letter dated February 1, 2006 to BCUC requesting a copy of BCTC's Archaeological Overview Assessment (Exhibit C1-4) |
| C1-31 | Letter dated February 2, 2006 responding to BCTC's response to BCUC's Information Request No. 4.203.1, 4.203.2 and 4.204.0 |
| C1-32 | Email dated February 2, 2006 requesting clarification on the Order of Cross-Examination for BCTC's Witness Panels |
| C1-33 | Submission at Public Hearing – Spreadsheet Entitled "Vancouver Island Transmission Reinforcement (VITR) Project – Comparison of Suggested Route Alternatives at Tsawwassen (IR 4.203.2 Jan 2006)" |
| C1-34 | Submission at Public Hearing – Email from Ms. Val Roddick, MLA, Dated December 5, 2005 |
| C1-35 | Submission at Public Hearing – Opening Statement of Karsten Holmsen |
| C1-36 | Submission at Public Hearing – Resume of Mr. Gallagher from BC Cancer Research Centre website |
| C1-37 | Submission at Public Hearing – Excerpt from 2003 Transcript of National Energy Board Hearings with Mr. Gallagher's responses to cross-examination |
| C2-1 | **SALT SPRING REGIONAL DISTRICT** – Notice of Intervention dated May 18, 2005 from Gary Holman, CRD Director |
| C2-2 | E-mail dated June 3, 2005 with questions regarding this process |
| C2-3 | E-mail dated July 26, 2005 with final submission from Salt Spring Regional District |
| C2-4 | E-mail dated October 5, 2005 – Support TRAVHOL's request for extension |

| Exhibit No. | Description |
|---|---|
| C2-5 | E-mail dated October 12, 2005 – Issues for Pre-hearing Conference Agenda |
| C3-1 | **TSAWWASSEN RESIDENTS AGAINST HIGHER VOLTAGE OVERHEAD LINES (TRAHVOL)** - Notice of Intervention dated June 21, 2005 from J. Cecil Dunn |
| C3-2 | Letter to the Honourable Richard Neufeld, Minister of Energy and Mines dated June 9, 2005 regarding BC Transmission Corporation's recent announcement of a power line route in Tsawwassen |
| C3-3 | Letter to the Honourable Richard Neufeld, Minister of Energy and Mines dated July 19, 2005 regarding this application |
| C3-4 | Letter dated July 23, 2005 requesting an extension to the July 29, 2005 Intervenor registration deadline and a rescheduling of the Procedural Conference |
| C3-5 | Letter dated July 25, 2005 confirming intervention and registering names of IRAHVOL representatives |
| C3-6 | E-mail dated July 27, 2005 responding to BC Transmission Corporation letter of July 23, 2005 (Exhibit B-3) |
| C3-7 | Letter dated July 29, 2005 to Minister Richard Neufeld, Ministry of Energy and Mines re: the Province's Commitment regarding Power Lines in Tsawwassen |
| C3-8 | E-mail dated August 4, 2005 from Maureen Broadfoot regarding Bruce Barrett's comments on Global Television's August 4, 2005 broadcast |
| C3-9 | E-mail dated August 6, 2005 from Maureen Broadfoot filing unanswered questions and new information requests |
| C3-10 | Letter dated August 10, 2005 offering the Commission Panel, the Applicant and all Intervenors/Interested Parties the opportunity to view a portion of the Tsawwassen corridor |
| C3-11 | Letter dated August 17, 2005 to Dennis Maniago regarding his comments on BCTC's expropriation of Tsawwassen residential property |
| C3-12 | Letter dated August 22, 2005 submitting an issue to be included within the scope of the VITR review |
| C3-13 | Notice of Counsel Appointments - E-mail dated September 7, 2005 |

| Exhibit No. | Description |
|---|---|
| C3-14 | Letter and Information Request No. 1 dated September 7, 2005 |
| C3-15 | E-mail dated September 11, 2005 from Maureen Broadfoot regarding unanswered questions and new information requests |
| C3-16 | E-mailed dated September 14, 2005 from Mark Underhill, Underhill Faulkner Bois Parker Law Corporation Inc. representing IRAHVOL along with co-counsel Joseph J. Arvay, Q.C., Arvay Finlay |
| C3-17 | Letter dated September 20, 2005 from Arvay Finlay in response to BCOAPO letter of September 15, 2005 |
| C3-18 | Letter dated October 4, 2005 from Arvay Finlay in response to BCTC's letter of September 30, 2005 |
| C3-19 | Letter dated October 5, 2005 from Arvay Finlay filing Evidence on behalf of IRAHVOL |
| C3-20 | Letter dated October 27, 2005 providing follow-up comments regarding the proposed corridor inspection by the Commission Panel |
| C3-21 | Letter dated November 8, 2005 – Formal complaint regarding Tsawwassen corridor |
| C3-22 | E-mail dated November 10, 2005 – Response to Commission Information Request No. 1 |
| C3-23 | E-mail dated November 10, 2005 – Partial Response to BCTC Information Request No. 1 |
| C3-24 | E-mail dated November 10, 2005 – Partial Response No. 2 to BCTC Information Request |
| C3-25 | E-mail dated November 10, 2005 – Response to BCOAPO Information Request |
| C3-26 | **TSAWWASSEN RESIDENTS AGAINST HIGH VOLTAGE OVERHEAD LINES SOCIETY** - Letter dated October 18, 2005 from Joseph J. Arvay Q.C., Arvay Finlay requesting Intervenor Status<br><br>***Previously C8-1 in Sea Breeze VIC proceeding** |
| C3-27 | Letter dated November 22, 2005 filing Partial Response No. 3 to BCTC's Information Request regarding the Intervenor Evidence of IRAHVOL |

| Exhibit No. | Description |
|---|---|
| C3-28 | Partial Response No. 4 dated December 1, 2005 to BCTC Information Request |
| C3-29 | Addendum to Appendix J to Partial Response No. 4 dated December 1, 2005 to BCTC Information Request (Exhibit C3-28) |
| C3-30 | Letter dated December 12, 2005 filing the Affidavit of Cornelia Clennan |
| C3-31 | E-mail dated December 16, 2005 from Maureen Broadfoot commenting on the draft Revised Regulatory Timetable (Exhibit A-45) |
| C3-32 | Letter dated December 20, 2005 commenting on the draft revised proceeding timetable |
| C3-33 | Letter dated December 23, 2005 from IRAHVOL's Counsel advising that he has a timing conflict with the Revised Regulatory Timetable |
| C3-34 | Letter dated January 20, 2006 from Mark Underhill, Underhill Faulkner Bois Parker Law Corporation Inc. filing a reply report from Dr. Magda Favas to Linda Erdreich |
| C3-35 | Email dated January 26, 2006 from Joseph Arvay of Arvay Finlay Barristers requesting a modification to the Order of Witness Panels due to availability of their EMF expert witness |
| C3-36 | Letter dated February 3, 2006 advising that TRAHVOL will be submitting an additional issue for the Hearing Issues List at the commencement of the Public Hearing |
| C3-37 | "Vancouver Island transmission Reinforcement (VITR) – Tsawwassen Route Alternatives Evaluation" prepared by British Columbia Transmission Corporation |
| C3-38 | Article from the Vancouver Province dated February 7, 2006 entitled "Sparks Likely to Fly at Power-Line Hearing" |
| C3-39 | Submission at Public Hearing – BCTC News Release dated September 7th, 2005 |
| C3-40 | Submission at Public Hearing – Affidavit of Neil Atchison |
| C3-41 | Submission at Public Hearing – Affidavit of Marcia Newman |

| Exhibit No. | Description |
|---|---|
| C3-42A | Submission at Public Hearing – Neil Atchison's working notes, pages 1-15 |
| C3-42B | Submission at Public Hearing – Neil Atchison's working notes, pages 1-9 |
| C3-42C | Submission at Public Hearing – Neil Atchison's working notes, email dated February 1, 2006 |
| C3-43 | Submission at Public Hearing – Email from Neil Atchison to Marcia Newman dated February 1, 2006 |
| C3-44 | Submission at Public Hearing – "Tsawwassen's Endangered Spaces 2006 Calendar |
| C3-45 | Submission at Public Hearing – "Opening Statement – TRAHVOL, BCUC VITR/VIC Hearing, February 27, 2006 |
| C3-46 | Submission at Public Hearing – Editorial from The Delta Optimist dated February 22, 2006 |
| C3-47 | Submission at Public Hearing – TRAHVOL Powerpoint presentation |
| C3-48 | Submission at Public Hearing – List of TRAHVOL meeting dates |
| C3-49 | Submission at Public Hearing – Executive Summary of Report of Delpizzo, Neutra and Lee |
| C3-50 | Submission at Public Hearing – Decision of the Public Utilities Commission of the State of California in the matter of the Application of Pacific Gas and Electric Company for a Certificate of Public Convenience and Necessity |
| C3-51 | Submission at Public Hearing – Decision of the Public Utilities Commission of the State of California, January 26, 2006 |
| C3-52 | Submission at Public Hearing – Health Effects ABD Exposure Guidelines related to extremely low frequency electric and magnetic fields, an overview |
| C3-53 | Submission at Public Hearing – Overall evaluations of carcinogenicity to humans group 2B: Possibly carcinogenic to Humans |
| C3-54 | Submission at Public Hearing – Transcript from Larry King Live Show |
| C3-55 | Submission at Public Hearing – Excerpt from "EMF Wrappage" booklet from NIEHS |

| Exhibit No. | Description |
|---|---|
| C3-56 | Submission at Public Hearing – Document showing different possible scenarios of EMF |
| C3-57 | Submission at Public Hearing – Draft Report on Relation between power frequency electric and magnetic filed exposure and human cancer |
| C3-58 | Submission at Public Hearing – Population-based case-control study of occupational exposure to electromagnetic fields and breast cancer |
| C3-59 | Submission at Public Hearing – Pollan Report |
| C3-60 | Submission at Public Hearing – Kliukiene Study |
| C3-61 | Submission at Public Hearing – Villeneuve Study |
| C3-62 | Letter dated March 29, 2006 filing response to Undertaking at Transcript, Volume 23, page 4411 |
| C4-1 | **BRADLEY W. CAMPBELL** - Notice of Intervention dated July 11, 2005 |
| C4-2 | E-mail dated November 10, 2005 – Support IRAHVOL's complaint with proceedings. |
| C4-3 | Opening Statement by Mr. Campbell |
| C4-4 | Submission at Public Hearing - BC Hydro Power Live Easement Summary, 2 pages |
| C5-1 | **CORPORATION OF DELTA** - Notice of Intervention dated February 15, 2005 and confirmation letter dated July 15, 2005 from James G. Yardley, Murdy & McAllister |
| C5-2 | Letter dated June 28, 2005 from Mayor Lois E. Jackson regarding BC Transmission Corporation's proposal to replace the transmission lines between Arnott substation in South Delta and Vancouver Island |
| C5-3 | Information Requests dated September 7 & 8, 2005 from James G. Yardley, Murdy & McAllister |
| C5-4 | Letter dated September 29, 2005 – Submission from James G. Yardley, Murdy & McAllister |
| C5-5 | Facsimile dated October 5, 2005 – Support Intervenors request for extension |

| Exhibit No. | Description |
|---|---|
| C5-6 | Letter dated October 19, 2005 – Pre-filed Evidence of Trent Reid from James G. Yardley, Murdy & McAllister |
| C5-7 | Facsimile dated November 3, 2005 – Propose Theatre at South Delta Secondary School for Town Hall Meetings |
| C5-8 | Letter dated November 10, 2005 – Responses to Commission Information Requests |
| C5-9 | Letter dated November 10, 2005 – Responses to BCOAPO Information Requests |
| C5-10 | Letter dated November 10, 2005 – Responses to BCTC Information Requests |
| C5-11 | **CORPORATION OF DELTA** – Facsimile dated October 18, 2005 from James. G. Yardley, Murdy & McAllister requesting Intervenor Status |
| | ***Previously C7-1 in Sea Breeze VIC proceeding** |
| C5-12 | Letter dated December 9, 2005 filing outstanding responses to Commission Information Request No. 1 |
| C5-13 | Letter dated December 7, 2005 filing outstanding response to BCTC IR-1 |
| C5-14 | E-mail dated December 19, 2005 commenting on the proposed change in date and time for the Tsawwassen Town Hall meeting |
| C5-15 | Letter dated January 27, 2006 from James G. Yardley, Murdy & McAllister advising of Dr. Robin Gregory's unavailability and requesting the Commission to reschedule Delta's Witness Panel or that Dr. Gregory's attendance be rescheduled as a separate panel |
| C5-16 | Letter dated January 31, 2006 from James G. Yardley, Murdy & McAllister regarding the City of Delta's response to Transcript Volume 6 pp. 890, Issue No. 5 |
| C5-17 | Letter dated February 2, 2006 from James G. Yardley, Murdy & McAllister regarding BCUC's Information Request No. 1.3 (Exhibit B1-6) |
| C5-18 | Submission at Public Hearing – Witness Aid with respect to description of BC Hydro Easements in Tsawwassen |
| C5-19 | Submission at Public Hearing – Extracts of Tsawwassen First Nations Agreement in Principle |

| Exhibit No. | Description |
|---|---|
| C5-20 | Submission at Public Hearing – Response to Outstanding Undertakings to Corporation of Delta |
| C5-21 | Letter dated March 29, 2006 filing response to outstanding Undertakings in Transcript – Public Hearing – Volume 21 |
| C6-1 | **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** - Notice of Intervention dated July 13, 2005 |
| C6-2 | Letter dated October 19, 2005 – Direct Testimony of Kenneth H. Tiedemann |
| C6-3 | Letter dated October 26, 2005 – Information Request to Hul'qumi'num |
| C6-4 | Letter dated November 10, 2005 – Response to Commission Information Request No. 1 |
| C6-5 | Letter dated November 15, 2005 – Response to Hul'qumi'num Treaty Group Submissions |
| C6-6 | **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY –** Web registration dated October 6, 2005 requesting Intervenor Status |
| | ***Previously C1-1 in Sea Breeze VIC proceeding** |
| C6-7 | Letter dated November 18, 2005 filing Information Request No. 1 to Sea Breeze re: VIC Application |
| C6-8 | Letter dated December 12, 2005 filing the Direct Testimony of James Edward Fralick |
| C6-9 | Letter dated December 20, 2005 commenting on the draft revised proceeding timetable |
| C6-10 | Letter dated December 29, 2005 responding to IRAHVOL's counsel letter of December 23, 2005 (Exhibit C3-33) |
| C6-11 | Letter dated February 7, 2006 to Commission regarding James Edward Fralick's qualifications and his Curriculum Vitae |
| C6-12 | Submission at Public Hearing – Letter from Mr. Sanderson to Mr. Landry |
| C6-13 | Submission at Public Hearing – Two page cover letter |

| Exhibit No. | Description |
|---|---|
| C6-14 | Submission at Public Hearing - Direct Testimony of Tony Morris, Manager, Enterprise Strategy and Investment with British Columbia Hydro and Power Authority |
| C6-15 | Submission at Public Hearing – Witness Aid: Revised Proposal: Roles and Responsibilities |
| C6-16 | Submission at Public Hearing – Sea Breeze Power Corp 20FR12G filing on July 7, 2005 for the year ended December 31, 2004 |
| C6-17 | Submission at Public Hearing – Exhibit 4.18, Limited Partnership Agreement of Sea Breeze Pacific Juan De Fuca Cable LP |
| C6-18 | Submission at Public Hearing – Exhibit 4.19, Development Loan Agreement |
| C6-19 | Submission at Public Hearing – Extract from Schedule 1.3 of the Development Loan Agreement regarding the Juan De Fuca Project |
| C6-20 | Submission at Public Hearing – GANTT Chart filed with NEB |
| C6-21 | Submission at Public Hearing – Filing with NEB Re: corporate experience of Sea Breeze Group of Companies |
| C6-22 | Submission at Public Hearing – Response to BC Hydro Information Request 18.0 Called Appendix 18.3 and 18.4 |
| C6-23 | Submission at Public Hearing – National Energy Board response to BC Hydro |
| C6-24 | Submission at Public Hearing – Response to BCTC Question 1 |
| C6-25 | Submission at Public Hearing – Excerpt, Page 8 & 9, NEB |
| C6-26 | Submission at Public Hearing – Commission Order Letter No. L-104-05 dated December 2, 2005 establishing the 2006 Return on Common Equity for a Low-Risk Benchmark Utility |
| C6-27 | Letter dated March 29, 2006 filing response to various Undertakings in Transcript – Public Hearing - Volume 35 |
| C6-28 | Letter dated April 3, 2006 from Lawson Lundell requesting removal of response to the undertakings filed by Sea Breeze on March 29, 2006 as part of Exhibit C31-57 |

| Exhibit No. | Description |
|---|---|
| C7-1 | **JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** - Notice of Intervention dated July 13, 2005 |
| C7-2 | **JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE** – Letter dated October 17, 2005 from R. Brian Wallace, Bull Housser & Tupper requesting Intervenor Status also including Lloyd Guenther, LSM Consulting |
| | ***Previously C5-1 in Sea Breeze VIC proceeding** |
| C7-3 | Letter dated December 20, 2005 commenting on BC Hydro's submission regarding the possibility of a delay in the January public hearing (Exhibit C6-9) |
| C7-4 | Opening Statement of Joint Industry Steering Committee |
| C8-1 | **NEIL ATCHISON** - Notice of Intervention dated July 19, 2005 |
| C9-1 | **JOHN R. BULLOCH** - Notice of Intervention dated July 19, 2005 |
| C9-2 | Letter dated August 25, 2005 requesting that an on site in situ ground inspection take place |
| C9-3 | Submission at Tsawwassen Town Hall Meeting |
| C10-1 | **ISLANDS TRUST** - Notice of Intervention dated July 19, 2005 from Linda Adams |
| C10-2 | Letter dated July 19, 2005 confirming Islands Trust intervention |
| C10-3 | Letter dated August 18, 2005 requesting rescheduling of Town Hall meeting on November 19 due to Local General Elections on the same date |
| C10-4 | Letter dated October 12, 2005 regarding proposed locations and times for Town Hall Meetings |
| C10-5 | Letter dated October 19, 2005 submitting Intervenor Evidence |
| C10-6 | Letter dated November 10, 2005 – Response to Commission Information Request No. 1 |
| C10-7 | Letter dated November 10, 2005 – Response to BCTC Information Request |
| C10-8 | Letter dated December 21, 2005 filing Evidence from Islands Trust |

| Exhibit No. | Description |
|---|---|
| C10-9 | Letter dated January 23, 2006 from Linda Adams responding to Commission's Information Request No. 1 |
| C11-1 | **DARRYL & GEETA SCHALLIG** - Notice of Intervention dated July 19, 2005 |
| C11-2 | Letter dated July 20, 2005 with reasons for intervention |
| C11-3 | Submission at Tsawwassen Town Hall Meeting from Daryl Schallig - Original presentation unavailable, copy of transcript provided instead - Transcript Volume 5, Page 716 line 15 to Page 725 line 24 |
| C12-1 | **LYNETTE OLFERT** - Notice of Intervention dated July 21, 2005 |
| C12-2 | Intervention Withdrawn – See Interested Party D-36 |
| C13-1 | **TRANSCANADA ENERGY LTD.** - Notice of Intervention dated July 21, 2005 from Alan Ross |
| C14-1 | **RANDY BOUSFIELD** - Notice of Intervention dated July 21, 2005 |
| C15-1 | **WILLIAM A. SHARKEY** - Notice of Intervention dated July 22, 2005 |
| C15-2 | Submission at Tsawwassen Town Hall Meeting |
| C16-1 | **JOHN CROSS** - Notice of Intervention dated July 25, 2005 |
| C16-2 | Information Request No. 1 dated September 7, 2005 |
| C16-3 | E-mail dated December 11, 2005 giving notice of a Town Hall presentation on behalf of the Tsawwassen Homeowners Association |
| C16-4 | E-mail dated January 8, 2006 advising the Commission that a presentation will not be made at the Tsawwassen Town Hall Meeting on January 14, 2006 |
| C16-5 | Letter dated January 29, 2006 requesting a change in status to Interested Party |
| C17-1 | **NORSKECANADA** - Notice of Intervention dated July 25, 2005 from Dennis Fitzgerald |
| C17-2 | Letter dated July 27, 2005 regarding reasons for intervention and support of the application |

| Exhibit No. | Description |
|---|---|
| C18-1 | **LIS BRIDSON** - Notice of Intervention dated July 23, 2005 |
| C18-2 | Intervention Withdrawn – see Exhibit D-42 |
| C19-1 | **NICK ARDANAZ** - Notice of Intervention received July 25, 2005 |
| C20-1 | **DON & IRENE HORN** - Notice of Intervention received July 25, 2005 |
| C20-2 | Letter received August 19, 2005 requesting a change in status to Interested Party (See Exhibit D-43) |
| C21-1 | **JULIE BERKS** - Notice of Intervention dated July 18, 2005 |
| C21-2 | Email dated August 23, 2005 inviting the Commission Panel members to view the right of way from her Shannon Way home |
| C21-3 | Letter dated September 16, 2005 responding to the Commission Panel's proposed inspection of the transmission line route |
| C21-4 | Letter dated October 26, 2005 providing follow-up comments regarding the proposed corridor inspection by the Commission Panel |
| C21-5 | Submission at Tsawwassen Town Hall Meeting |
| C22-1 | **LES MALZENICZKY** - Notice of Intervention dated July 23, 2005 |
| C22-2 | Intervention withdrawn – see Exhibit D-44 |
| C23-1 | **DR. & MRS. DAWSON** - Notice of Intervention dated July 20, 2005 |
| C24-1 | **VINCENT STROTHER** - Notice of Intervention dated July 21, 2005 |
| C24-2 | Letter of Comment dated August 24, 2005 |
| C25-1 | **OWNERS OF STRATA PLAN 905 AND SHAREHOLDERS OF MARACAIBO ESTATES LTD.** - Notice of Intervention dated July 26, 2005 from Charles L.A. Bazzard |
| C25-2 | Letter of Comment dated August 12, 2005 regarding the Procedural Conference and proposed process |

| **Exhibit No.** | **Description** |
|---|---|
| C25-3 | Letter dated October 18, 2005 – Evidence |
| C25-4 | E-mail dated October 19, 2005 – Recommend consolidation of BCTC VITR and Sea Breeze VIC project, submission also included |
| C25-5 | E-mail dated November 9, 2005 – Comment regarding Pre-Hearing Conference |
| C25-6 | E-mail dated November 9, 2005 – Response to BCTC Information Request |
| C25-7 | **MARACAIBO ESTATES LTD. AND THE OWNERS OF STRATA PLAN 905** – E-mail dated October 18, 2005 requesting Intervenor Status from Charles Bazzard |
| | ***Previously C15-1 in Sea Breeze VIC proceeding** |
| C25-8 | Letter dated December 31, 2005 responding to BCTC's Rebuttal Evidence dated December 16, 2005 |
| C25-9 | Submission at Salt Spring Town Hall Meeting – Atlas "Islands in the Salish Sea" |
| C25-10 | Submission at Salt Spring Town Hall Meeting – Overhead Transmission Lines Powerpoint presentation |
| C25-11 | Email dated January 24, 2006 responding to Exhibit A-62 advising of Mr. Bazzard's intention to make an Opening Statement on behalf of Maracaibo Estates Ltd and the Owners of Strata Plan 905 |
| C25-12 | Email dated January 26, 2006 Requesting Leave to make an Opening Statement |
| C25-13 | Letter dated January 29, 2006 submitting Opening Statement of Mr. Bazzard |
| C26-1 | **THE BC OLD AGE PENSIONERS ORGANIZATION *ET AL*. (BCOAPO)** - Notice of Intervention dated July 25, 2005 from Richard Gathercole of the BC Public Interest Advocacy Centre on behalf of the BCOAPO |
| C26-2 | Letter dated August 24, 2005 commenting on the invitations to the Panel to view the proposed Salt Spring Corridor |
| C26-3 | Information Request No. 1 dated September 7, 2005 |
| C26-4 | Letter dated September 15, 2005 commenting on the Panel's proposed inspection of the proposed transmission line corridor |

| Exhibit No. | Description |
|---|---|
| C26-5 | Letter dated October 26, 2005 – Information Request to Corporation of the City of Delta |
| C26-6 | Letter dated October 26, 2005 – Information Request to IRAHVOL |
| C26-7 | **BC Old Age Pensioners' Organization** – E-mail registration dated October 7, 2005 requesting Intervenor Status represented by The British Columbia Public Interest Advocacy Centre |
| | ***Previously C2-1 in Sea Breeze VIC proceeding** |
| C26-8 | Letter dated December 19, 2005 commenting on the draft revised Regulatory Timetable |
| C26-9 | Submission at Public Hearing – Salt Spring IRAHVOL petition |
| C27-1 | **HUL'QUMI'NUM TREATY GROUP** - Notice of Intervention dated July 25, 2005 from Robert Morales |
| C27-2 | Facsimile dated October 4, 2005 – Support request for extension |
| C27-3 | Facsimile dated October 12, 2005 – Submit issues for consideration at upcoming Hearing |
| C27-4 | Facsimile dated October 17, 2005 - Evidentiary submission from Kathleen Johnnie |
| | **Withdrawn** |
| C27-5 | Facsimile dated October 19, 2005 – Official Evidentiary submission from Kathleen Johnnie |
| C27-6 | Letter dated October 28, 2005 confirming HTG's interest in accepting the Commission's offer of additional time to support the various Order requests included HTG's October 19, 2005 submission |
| C27-7 | Supplemental Submission dated November 2, 2005 |
| C27-8 | **HUL'QUMI'NUM TREATY GROUP** - Web registration dated October 17, 2005 from Kathleen Johnnie requesting Intervenor Status |
| | ***Previously C4-1 in Sea Breeze VIC proceeding** |
| C27-9 | E-mail dated November 18, 2005 – Response to BC Hydro Information Request No. 1 (Exhibit C6-3) |

| Exhibit No. | Description |
|---|---|
| C27-10 | Letter dated November 21, 2005 submitting questions to the Environmental Assessment Office regarding the BCTC Vancouver Island Transmission Project and the Sea Breeze Vancouver Island Cable Project |
| C27-11 | HTG's Reply Submissions dated November 22, 2005 |
| C27-12 | Letter dated November 23, 2005 requesting an extension of time to allow HTG to respond to BC Hydro's Reply Submission (Exhibit C6-5) |
| C27-13 | Letter dated January 6, 2006 notifying the Applicants and the Commission of their duty to consult with the Hul'qumi'num Treat Group and the Hul'qumi'num Mustimuhw |
| C28-1 | **PRISTINE POWER INC.** - Notice of Intervention dated July 26, 2005 from Loyola G. Keough, Bennett Jones LLP |
| C29-1 | **COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA** - Notice of Intervention dated July 29, 2005 from Christopher Weafer |
| C29-2 | Submission at Public Hearing – Excerpt from BC Hydro's Annual Report entitled Management Report |
| C29-3 | Submission at Public Hearing – Extracts from five historical BC Hydro Annual Reports "Consolidate Financial Statements |
| C30-1 | **MCLENNAN, MAIRI** – Web registration and e-mail dated July 29, 2005 |
| C30-2 | Letter dated December 20, 2005 commenting on the draft Revised Regulatory Timetable |
| C31-1 | **SEA BREEZE PACIFIC REGIONAL TRANSMISSION SYSTEM, INC.**– Notice of Intervention dated July 29, 2005 from Paul B. Manson |
| C31-2 | Letter and Information Request No. 1 dated September 7, 2005 |
| C31-3 | Letter dated October 14, 2005 – Notice of Assignment |
| C31-4 | Letter dated October 17, 2005 – Submission from P. John Landry, Davis & Company |
| C31-5 | Letter dated October 18, 2005 – Submission regarding consolidation application from P. John Landry, Davis & Company |

| Exhibit No. | Description |
|---|---|
| C31-6 | Web submission dated October 19, 2005 – Intervenor Evidence |
| C31-7 | Letter dated October 20, 2005 – Copies of authorities referred to in Exhibit C31-5 |
| C31-8 | Duplicate of Exhibit C31-6 |
| C31-9 | E-mail dated October 20, 2005 – Draft Terms of Reference (Version 1) regarding the Vancouver Island Cable Project |
| C31-10 | E-mail dated November 14, 2005 – Responses to Commission Information Request No. 1 |
| C31-11 | Submission at Public Hearing – Letter from J.P. Landry, Davis & Company, dated March 2, 2006, with attached revised Witness Panel List |
| C31-12 | Submission at Public Hearing – Revised Version of Exhibit C31-11 |
| C31-13 | Submission at Public Hearing – Letter from Sea Breeze Victoria Converter Corporation to Mr. David Pollack, City of White Rock, with attachment |
| C31-14 | Submission at Public Hearing – Revised Opening Statement of Sea Breeze |
| C31-15 | Submission at Public Hearing – Response to two Information Requests by Mr. Fulton |
| C31-16 | Submission at Public Hearing – Supplementary response to BCTC and request of Mr. Carpenter re: GANTT Chart |
| C31-17 | Submission at Public Hearing – Revision to Sea Breeze Response to BCTC Information Request 1.39.2 |
| C31-18 | Submission at Public Hearing – Correction to Sea Breeze's response to Information Request No. 12 |
| C31-19 | Submission at Public Hearing – Response to request for information arising out of rebuttal evidence |
| C31-20 | Submission at Public Hearing – Direct Testimony of Sea Breeze Panel C |
| C31-21 | Submission at Public Hearing – Requests by Ms. Hansen and the Chairperson for a revised description of the Orders sought by Sea Breeze |
| C31-22 | Submission at Public Hearing – Correction to Response to Commission's Information Request No. 1.31.2 in Exhibit B2-11 |

| Exhibit No. | Description |
|---|---|
| C31-23 | Submission at Public Hearing – Sea Breeze Reply Evidence to Exhibit 6-14 |
| C31-24 | Submission at Public Hearing – Direct Evidence for Panel B |
| C31-25 | Submission at Public Hearing – Status Reports up to February 10, 2006 |
| C31-26 | Submission at Public Hearing – Project Status Report of March 10, 2006 |
| C31-27 | Submission at Public Hearing – Review of ABB HVBDC Cable Transmission Projects |
| C31-28 | Submission at Public Hearing – Response to Information Request at Transcript Volume 31, pages 6118 to 6120 |
| C31-29 | Submission at Public Hearing – Attachment to Exhibit B2-20 |
| C31-30 | Submission at Public Hearing – Direct Evidence for Sea Breeze Panel D |
| C31-31 | Submission at Public Hearing – Photographs of different IGBT Modules |
| C31-32 | Submission at Public Hearing – Document from original data re: VITR 2026/17 Winter Peak 2650 MW |
| C31-33 | Submission at Public Hearing – Undertaking at Transcript Volume 31, pages 6122 to 6123 |
| C31-34 | Submission at Public Hearing – Undertaking to a request of Mr. Carpenter at PP 5747-5749 |
| C31-35 | Submission at Public Hearing – Contractual status of key management personnel |
| C31-36 | Submission at Public Hearing – Confirmation regarding clause 711 of Development Loan Agreement Relating to Confidentiality |
| C31-37 | Submission at Public Hearing – Group of responses regarding HVDC light cables |
| C31-38 | Submission at Public Hearing – List of Milestones achieved in Evidence |
| C31-39 | Submission at Public Hearing – Response to Undertaking by Ms. Kane Re: Amendment to Status Reports |
| C31-40 | Submission at Public Hearing – Geological Survey of Canada Slope Map |
| C31-41 | Submission at Public Hearing – Extract from Commission's Ruling re: Vancouver Island Generation Project, CPCN Application, September 8, 2003 |

| Exhibit No. | Description |
|---|---|
| C31-42 | Submission at Public Hearing – Report from Canadian Electricity Association, March 2006, “The Integrated North American Electricity Market Et Al” |
| C31-43 | Submission at Public Hearing – Response to Undertaking at Transcript Volume 33, Page 6241 |
| C31-44 | Submission at Public Hearing – Response to Undertaking Transcript Volume 33, Page 6298 |
| C31-45 | Submission at Public Hearing – Response to Undertaking Transcript Volume 32, Page 6032 |
| C31-46 | Submission at Public Hearing – Response to Undertaking Transcript Volume 32, Page 6034 |
| C31-47 | Submission at Public Hearing – Sea Breeze response to City of White Rock letter |
| C31-48 | Submission at Public Hearing – Correction to the Record arising out of a request by Mr. Carpenter for a more legible copy of Exhibit C31-32 |
| C31-49 | Submission at Public Hearing – BCTC Standards of Conduct |
| C31-50 | Submission at Public Hearing – Redacted Version of Information Request of BCTC to Sea Breeze dated March 16, 2006 |
| C31-51 | Submission at Public Hearing – Page 4 of Final Marine Route of Proposed 16” GSX Pipeline |
| C31-52 | Submission at Public Hearing – Letter from Energy Investors Funds and Attachments of March 14, 2006 |
| C31-53 | Submission at Public Hearing – Sea Breeze Response to Information Request form BCTC |
| C31-54 | Submission at Public Hearing – E-mail from Mr. Herbert containing an e-mail from Mr. Schroeder to Mr. Landry with answers to various questions |
| C31-55 | Submission at Public Hearing – CV of Andrew E. Schroeder |
| C31-56 | Submission at Public Hearing – Excerpt from the Peace Arch News, dated March 11, 2006 |
| C31-57 | Responses to various Undertakings at Transcript Volume 30 through to Volume 40 |

| Exhibit No. | Description |
|---|---|
| C31-58 | Letter dated April 4, 2006 filing response to BC Hydro's Application to strike a portion of Sea Breeze's Response to Undertakings to BC Hydro (Exhibit C6-28) |
| C32-1 | **ELK VALLEY CORPORATION** – Notice of Intervention dated July 27, 2005 from J. David Newlands |
| C33-1 | **TERASEN GAS INC.** – Web Registration received August 3, 2005 from Scott Thomson |
| C34-1 | **ISLAND RESIDENTS AGAINST HIGH VOLTAGE OVERHEAD LINES (IRAHVOL)**– Notice of Intervention dated August 3, 2005 from David Austin and Daria Zovi |
| C34-2 | Letter and Information Request No. 1 dated September 7, 2005 |
| C34-3 | Letter and Information Request No. 1 dated September 8, 2005 (Revised) |
| C34-4 | Letter dated October 3, 2005 requesting an equivalent extension to October 20, 2005 for the purposes of filing its Intervenor evidence |
| C34-5 | Letter dated October 7, 2005 requesting that the issue of the scope of the Commission's review of the VITR Project as it relates to socio-economic and environmental issues, be placed on the October 21, 2005 pre-hearing conference agenda |
| C34-6 | Letter dated October 19, 2005 – Submission of policy evidence |
| C34-7 | Letter dated November 15, 2005 – Response to Commission Information Request No. 1 |
| C34-8 | **ISLAND RESIDENTS AGAINST HIGH VOLTAGE OVERHEAD LINES** – E-mail dated October 18, 2005 from David Austin, Tupper Jonnson and Yeadon requesting Intervenor Status<br>***Previously C6-1 in Sea Breeze VIC proceeding** |
| C34-9 | Letter dated November 15, 2005 filing responses to BCTC Information Request No. 1 |
| C34-10 | Letter dated December 21, 2005 filing IRAHVOL's Evidence |
| C34-11 | Letter dated December 29, 2005 requesting the Commission Panel's leave to make a presentation at the Town Hall Meeting on Salt Spring Island |

| Exhibit No. | Description |
|---|---|
| C34-12 | Submission at Salt Spring Town Hall Meeting regarding health hazards for patients with pacemakers |
| C34-13 | Letter dated January 9, 2006 issuing Information Request No. 2 to BCTC regarding its December 21, 2005 Rebuttal Evidence |
| C34-14 | **REVISED** - Letter dated January 13, 2006 to the Honourable Barry Penner, Minister of Environment; Wally Oppal, QC, Attorney General and Richard Neufeld, Minister of Energy, Mines & Petroleum Resources regarding the regulatory reviews of the VITR and VIC projects |
| C34-15 | Letter dated January 23, 2006 IRAVHOL's responding to the Commission Information Request No. 1 |
| C34-16 | Submitted at the Public Hearing<br>Document Headed "4.0 Reference: Application, Tab Introduction, page 11, CPCN Criteria" |
| C34-17 | Excerpts from British Columbia Transmission Corporation "Introduction and Context for Baseline Study dated April 2005 |
| C34-18 | Map "Vancouver Island Region" in relation to 25 kV Supply to Gulf Islands |
| C34-19 | Submission at Public Hearing – Web pages from Federal Department of Fisheries & Oceans |
| C34-20 | Submission at Public Hearing – Archival Materials from Delta Museum Archives |
| C34-21 | Submission at Public Hearing – IRAHVOL's Policy Panel Opening Statement |
| C34-22 | Submission at Public Hearing – BC Hydro's Service Plan 2006/07 to 2008/09 |
| C34-23 | Submission at Public Hearing – BCTC Service Plan for Fiscal Years 2006/07 to 2008/09, dated January 2006 |
| C34-24 | Submission at Public Hearing – Budget and Fiscal Plan, 2006/07 – 2008/09, dated February 21, 2006, BC Ministry of Finance |
| C34-25 | Submission at Public Hearing – Extracts from BC Hydro's Service Plan 2005/06 and 2007/08, Service Plan Update 2005 |
| C34-26 | Submission at Public Hearing – Press Release Forrest Kerr Project Interconnection Facilities approved by the BCTC |

| Exhibit No. | Description |
|---|---|
| C34-27 | Submission at Public Hearing – BC Hydro's 1995 Integrated Electricity Plan, Appendix H, Transmission Analysis of the 1995 Integrated Electricity Plan |
| C34-28 | Submission at Public Hearing – Extract from BC Hydro's Electric Load Forecast 2003/04 to 2023/24 |
| C34-29 | Submission at Public Hearing – Extract from the BC Hydro Revenue Requirements Hearing |
| C34-30 | Submission at Public Hearing – "A Briefing on BC Hydro's Transmission Capacity Requirements" Prepared by BC Hydro Executive Operation, September 2002 |
| C34-31 | Submission at Public Hearing – 10th Annual Report, Year ended 31 March 1972, BC Hydro and Power Authority |
| C34-32 | Submission at Public Hearing – Letter from E. Livingston, P. Eng dated March 14, 1975 and attachments |
| C35-1 | **TRUSCOTT, DOUGLAS AND JACKIE**– Notice of Intervention dated July 29, 2005 on behalf of the Oakspring Strata VIS 2431 |
| C35-2 | E-mail dated November 10, 2005 – Unable to fulfill obligations as an Intervenor |
| C35-3 | **DOUGLAS AND JACKIE TRUSCOTT** – E-mail dated October 18, 2005 requesting Intervenor Status |
| | ***Previously C12-1 in Sea Breeze VIC proceeding** |
| C35-4 | Letter of comment on health hazards from Jackie Truscott submitted at Salt Spring Town Hall Meeting |
| C35-5 | Letter of comment on health hazards from Doug Truscott submitted at Salt Spring Town Hall Meeting |
| C36-1 | **SUTHERLAND, PAM**– Notice of Intervention dated August 8, 2005 |
| C36-2 | E-mail dated August 11, 2005 advising the Panel that should they undertake an inspection of the Tsawwassen corridor, that her property is available for visitation |
| C36-3 | Facsimile dated October 18, 2005 – Property Values and Proposed Expropriation |

| **Exhibit No.** | **Description** |
|---|---|
| C36-4 | Submission at Public Hearing – Responses of Ms. Sutherland |
| C36-5 | Letter dated February 2, 2006 – Notice to Appear |
| C37-1 | **BAKER, LORRAINE**– Notice of Intervention received August 8, 2005 |
| C38-1 | **BOYCE, SHARI**– Notice of Intervention received August 16, 2005 |
| C38-2 | Submission at Public Hearing – Written Presentation of S. Boyce |
| C39-1 | **SENCOT'EN ALLIANCE** – Notice of Intervention dated July 28, 2005 (received August 18, 2005) from Eric Pelkey and Susan Anderson Behn |
| C39-2 | **SENCOT'EN ALLIANCE** – Facsimile dated October 19, 2005 registering for Intervenor Status<br><br>***Previously C10-1 in Sea Breeze VIC proceeding** |
| C40-1 | **BROADFOOT, Maureen** – Notice of Intervention dated August 16, 2005 on behalf of a committee of concerned parents at South Delta Secondary High School |
| C40-2 | Letter dated March 3, 2005 from Maureen Broadfoot to Premier Gordon Campbell requesting that the government intervene in BCTC's VITR Application **and** Letter dated March 1, 2005 from Maureen Broadfoot to The Honourable Richard Neufeld, Minister of Energy and Mines requesting that the government intervene in BCTC's VITR Application |
| C40-3 | E-mail dated October 16, 2005 – Submission regarding Information Request Responses |
| C40-4 | E-mail dated October 31, 2005 – Submission of News Articles |
| C40-5 | E-mail dated January 3, 2006 requesting clarification regarding presentations at the Town Hall Meetings |
| C40-6 | E-mail dated January 7, 2006 attaching an article entitled "Discrepancy over figures for lines" by Maureen Gulyas for the Delta Optimist |
| C40-7 | E-mail dated January 8, 2006 providing the text of an article from the South Delta Leader entitled "Some Suggestive Scenes" |

| Exhibit No. | Description |
|---|---|
| C40-8 | E-mail dated January 7, 2006 providing the text of an article by Philip Raphael entitled "Newsmaker of the Year: IRAHVOL" |
| C40-9 | E-mail dated January 12, 2006 filing an article from the Delta Optimist entitled "A Matter of Health" |
| C40-10 | Email dated January 20, 2006 letter of comment with article from Delta Optimist "Prudent Decision Required" |
| C40-11 | Email dated January 20, 2006 letter of comment with article from Delta Optimist "BCUC is urged to reject plan" |
| C40-12 | Email dated January 4, 2006 letter of comment enclosing an article from the Delta Optimist entitled "In the Public Interest?" |
| C41-1 | **SOUTH DELTA SECONDARY SCHOOL PARENT ADVISORY COUNCIL** – Notice of Intervention dated August 22, 2005 from Janice Ristow |
| C41-2 | Web filing dated October 14, 2005 – Submission |
| C41-3 | Letter dated November 10, 2005 – Responses to BCTC Information Request No. 1 and Commission Information Request No. 1 |
| C41-4 | Opening Statement of Ms. Kudzin for South Delta School Parents' Advisory Council |
| C41-5 | Submission at Public Hearing – Equakealert document |
| C41-6 | Submission at Public Hearing – School Emergency Exit Plan |
| C41-7 | Submission at Public Hearing – Document "Seven Steps to Electrical Safety" |
| C41-8 | Submission at Public Hearing – Question of Mr. Karow to Dr. Ahlbom from BCUC website |
| C41-9 | Submission at Public Hearing – Resolution of South Delta Senior Secondary School Parent Advisory Committee |
| C42-1 | **BOLIRINNO, JOEQYNA** – Notice of Intervention dated August 23, 2005 |
| C42-2 | Submission at Public Hearing – Written text of presentation by Ms. Bolirinno |
| C43-1 | **PAGET, N.R.G.** – Notice of Intervention dated August 23, 2005 |

| Exhibit No. | Description |
|---|---|
| C44-1 | **BOLUS, LEONARD G.** – Notice of Intervention and Information request received August 24, 2005 |
| C45-1 | **DELTA SCHOOL DISTRICT –** Notice of Intervention dated September 8, 2005 from Grant McRadu |
| C45-2 | Letter dated May 13, 2005 to Mr. Michael Costello, President and Chief Executive Officer, British Columbia Transmission Corporation |
| C45-3 | Statement of Heather King on behalf of the Delta School District |
| C45-4 | Submission at Public Hearing – Letter of Comment / Submission from the Delta School District |
| C46-1 | **COALITION TO REDUCE ELECTROPOLLUTION –** Notice of Intervention received September 13, 2005 from Hans Karow |
| C46-2 | E-mail dated September 28, 2005 – Submission |
| C46-3 | Letter dated October 3, 2005 advising that copies of the proceeding documentation had not yet been provided |
| C46-4 | E-mail dated October 5, 2005 – Request for hard copies and clarification of deadline for Information Requests |
| C46-5 | E-mail dated October 19, 2005 – Request submission be read at Pre-hearing conference |
| C46-6 | E-mail dated October 19, 2005 – Submission regarding Exhibit A-19<br>**Withdrawn** |
| C46-7 | **COALITION TO REDUCE ELECTROPOLLUTION** – E-mail dated October 18, 2005 requesting Intervenor Status from Hans Karow<br>***Previously C14-1 in Sea Breeze VIC proceeding** |
| C46-8 | Letter dated December 27, 2005 submitting a one page summary/assessment of EMF studies in the Bonneville Power publication “Electrical and Biological Effects of Transmission Lines: A Review” |

| Exhibit No. | Description |
|---|---|
| C46-9 | E-mail dated January 16, 2006 to Commissioner Hobbs from Hans Karow/CORE asking him if he would live near high voltage transmission lines exposing his family to EMF |
| C47-1 | **RODDICK, VALERIE MLA –** Notice of Intervention received September 13, 2005 |
| C47-2 | E-mail dated January 3, 2006 requesting clarification regarding presentations made at the Town Hall Meetings |
| C47-3 | Submission at Tsawwassen Town Hall Meeting |
| C48-1 | **GSX CONCERNED CITIZENS COALITION (GSXCCC) –** Notice of Intervention dated September 16, 2005 |
| C49-1 | **CLEAN ENERGY FOUNDATION –** Notice of Intervention dated September 17, 2005 from Milt Bowling |
| C50-1 | **PLUMPTON, SUSAN AND CLIFF**– Notice of Late Intervention dated September 22, 2005 |
| 50-2 | Letter dated December 20, 2005 submitting Information Request No. 1 |
| C51-1 | **NAM, KYONG H.** – Notice of Intervention dated October 11, 2005 |
| C51-2 | Submission dated October 7, 2005 regarding EMF’s and Health Hazards |
| C51-3 | Letter dated January 12, 2006 commenting on the Town Hall Meetings |
| C51-4 | Letter dated January 30, 2006 commenting that the transmission lines were being used to transmit signals other than 60 cycles |
| C51-5 | Letter dated February 2, 2006 requesting information on health hazards and use of professional designation with APEGGA |
| C51-6 | Letter dated February 6, 2006 regarding Intervenor Evidence Supplement for Public Hearing on EMF and Health Hazards, provided upon request of Mr. Fulton, Counsel |
| C51-7 | Submission at Public Hearing – Series of emails to and from Dr. Nam |

| **Exhibit No.** | **Description** |
|---|---|
| C52-1 | **TOWN OF VIEW ROYAL** – E-mail dated October 17, 2005 from Emmet McCusker requesting Intervenor Status<br><br>***Previously C3-1 in Sea Breeze VIC proceeding** |
| C53-1 | **HOLMAN, GARY** – E-mail dated October 18, 2005 requesting Intervenor Status<br><br>***Previously C13-1 in Sea Breeze VIC proceeding** |
| C54-1 | **GSX CONCERNED CITIZENS COALITION** – Notice of Intervention dated October 19, 2005 from Arthur Caldicott<br><br>***Previously C16-1 in Sea Breeze VIC proceeding** |
| C55-1 | **HARVIE, George**– Notice of Intervention dated October 18, 2005 (The Corporation of Delta)<br><br>***Previously C17-1 in Sea Breeze VIC proceeding** |
| C56-1 | **SALT SPRING ISLAND LOCAL TRUST COMMITTEE** – Notice of Intervention dated October 18, 2005 from Kimberly Lineger<br><br>***Previously C18-1 in Sea Breeze VIC proceeding** |
| C57-1 | **CITY OF WHITE ROCK** – Notice of Intervention dated October 25, 2005 from Mayor Judy L. Forster<br><br>***Previously C19-1 in Sea Breeze VIC proceeding** |
| C57-2 | Letter dated December 21, 2005 filing Evidence from the City of White Rock |
| C57-3 | Letter dated January 23, 2006 from the City of White Rock responding to Commission Information Request No. 1 |
| C57-4 | Letter dated January 23, 2006 from the City of White Rock filing a Council Resolution and requesting Commission leave to file same as evidence with respect to the Sea Breeze VIC |
| C57-5 | Submission at Public Hearing – Letter containing two resolutions passed by the White Rock City Council |

| Exhibit No. | Description |
|---|---|
| C58-1 | **SONGHEES FIRST NATION** – Notice of Intervention dated October 27, 2005 from Chief Robert Sam<br><br>***Previously C20-1 in Sea Breeze VIC proceeding** |
| C59-1 | **CITY OF SURREY** – Notice of Intervention dated January 25, 2006 from Dianne L. Watts, Mayor |

### INTERESTED PARTY DOCUMENTS

| | |
|---|---|
| D-1 | Web registration dated July 11, 2005 from Heather Orr, Environmental Assessment Office |
| D-2 | Web registration dated July 19, 2005 from Margaret Atchison |
| D-3 | Web registration dated July 26, 2005 from Gary Williams |
| D-4 | Web registration dated July 26, 2005 from Karen Sweet |
| D-5 | Web registration dated July 26, 2005 from Kevin Jamieson |
| D-6 | Web registration dated July 27, 2005 from Danny Duch |
| D-7 | Web registration dated July 27, 2005 from Patti Purchas |
| D-8 | Web registration dated July 27, 2005 from Victor Villeneuve |
| D-9 | Web registration dated July 28, 2005 from Joan Purchas |
| D-10 | Web registration dated July 28, 2005 from Lorne Purchas |
| D-11 | Web registration dated July 28, 2005 from Guenter and Monika Schreiber |
| D-12 | Letter dated July 25, 2005 requesting Interested Party status from Myron Osatenko |
| D-13 | Letter dated July 19, 2005 requesting Interested Party status from Sheila Harrington |
| D-14 | Web registration dated July 29, 2005 from Christine & Alan Tobiason |
| D-15 | Web registration dated July 29, 2005 from Bert Schroeter |
| D-16 | Web registration dated July 29, 2005 from Greg G. Fahlman |

| Exhibit No. | Description |
|---|---|
| D-17 | Web registration dated July 29, 2005 from Mark Warwarick<br>August 3, 2005 submission entitled "Direct Current Transmission Lines" |
| D-18 | Web registration dated July 29, 2005 from Ray Carter |
| D-19 | Web registration dated August 3, 2005 from Darlene Morrison |
| D-19-1 | Letter of Comment received March 17, 2006 from Darlene Morrison |
| D-20 | Web registration dated August 3, 2005 from Kathy and Scott Mitchell |
| D-21 | Web registrations dated August 3, 2005 from Angela and Martin Kind |
| D-22 | Letters dated July 25, 2005 from John and Anne Noble |
| D-23 | Web registration received August 8, 2005 from Andrew Boyce |
| D-24 | Web registration received August 8, 2005 from J.R. Moran |
| D-25 | Letter dated July 26, 2005 from Edward Kenmare<br>Letter of Comment received August 10, 2005 |
| D-26 | Web registration received August 8, 2005 from R.J. Allinson |
| D-27 | Web registration received August 8, 2005 from Patricia Ellks |
| D-28 | Web registration received August 8, 2005 from K. Whitlum |
| D-29 | Web registration received August 8, 2005 from Mark Robinson |
| D-30 | Web registration received August 8, 2005 from Pat Lorimy |
| D-31 | Web registration received August 8, 2005 from John Bell |
| D-32 | Web registration received August 11, 2005 from Toan My To |
| D-33 | Letter dated August 11, 2005 from Reg and Gale Dawson |
| D-34 | Letter dated August 10, 2005 from Ben and Betty Dunstan |
| D-35 | Letter received August 12, 2005 from Carolyn and Don Allen |
| D-36 | Web registration received August 15, 2005 from Lynette Olfert requesting change to Interested Party status |
| D-37 | Web registration received August 15, 2005 from Mrs. Sung Nam |

| Exhibit No. | Description |
|---|---|
| D-38 | Web registration received August 15, 2005 from Andre and Maria de Ruijter |
| D-39 | Web registration received August 15, 2005 from Mark Timmons |
| D-40 | Letter dated August 13, 2005 from Joseph and Bernadette Kudzin |
| D-41 | E-mail dated August 17, 2005 from Don and Karen Parry |
| D-41-1 | Letter dated January 10, 2006 from Don & Karen Parry regarding property values along the existing right-of-way |
| D-42 | Letter dated August 13, 2005 Lis Bridson |
| D-43 | Letter received August 19, 2005 from Don and Irene Horn requesting a change in status to Interested Party (See Exhibit C20-2) |
| D-44 | Letter dated August 15, 2005 from Les Malzseniczky requesting a change in status to Interested Party |
| D-44-1 | Submission at Tsawwassen Town Hall Meeting |
| D-45 | Web registration requesting Interested Party status from Lesley Leake |
| D-46 | Web registration requesting Interested Party status from Glen Page |
| D-47 | Web registration requesting Interested Party status from Allen and Zara Cody |
| D-48 | Letter dated August 12, 2005 requesting Interested Party status from Bob and Wendy Childs |
| D-49 | E-mail dated August 24, 2005 requesting Interested Party status from Shelley Willms |
| D-50 | E-mail dated September 1, 2005 requesting Interested Party status and enclosing a March 3, 2005 Letter of Comment from Riaz & Fatima Pardhan |
| D-51 | E-mail dated September 2, 2005 requesting Interested Party status from Jim & Kelly Gallagher |
| D-52 | Web registration dated September 7, 2005 requesting Interested Party status from Lorraine Baker |
| D-53 | E-mail dated September 8, 2005 requesting Interested Party status from Jack S. Weddell |

| Exhibit No. | Description |
|---|---|
| D-54 | Web registration dated September 8, 2005 requesting Interested Party status from Florence Weisser |
| D-55 | Web registration dated September 11, 2005 Sukeina Jethabhai and Mohammad Meghjee requesting Interested Party status |
| D-56 | Web registration dated September 11, 2005 Peter Thesiger requesting Interested Party status |
| D-57 | Web registration dated September 13, 2005 requesting Interested Party Status from Ante Filipovic |
| D-58 | Web registration dated September 13, 2005 requesting Interested Party Status from Jonathan Jakubec |
| D-59 | Web registration dated September 13, 2005 requesting Interested Party Status from Dini Veldhuis |
| D-60 | E-mail dated September 15, 2005 from Jun & Cora Arguelles requesting Interested Party status |
| D-61 | Web registration dated September 17, 2005 requesting Interested Party Status from David R. Jones |
| D-62 | Web registration dated September 17, 2005 requesting Interested Party Status from Delores Savage |
| D-63 | Web registration dated September 17, 2005 requesting Interested Party Status from Mr. M. Anderson |
| | Letter of Comment received November 1, 2005 |
| D-64 | Web registration dated September 17, 2005 requesting Interested Party Status from Phil Ethier |
| D-65 | Web registration dated September 17, 2005 requesting Interested Party Status from Rocio Gonzalez |
| D-66 | Web registration dated September 17, 2005 requesting Interested Party Status from Vaclav Simek |
| D-67 | Web registration dated September 19, 2005 requesting Interested Party Status from Steven Reid |
| D-68 | Letter dated September 13, 2005 requesting change from Intervenor to Interested Party Status from Shirley C. and Robert L. Hanken |

| Exhibit No. | Description |
|---|---|
| D-69 | **JOY, Carmel** – Web registration dated October 8, 2005 requesting Interested Party status and Letter of Comment dated October 8, 2005<br><br>***Previously D-1 in Sea Breeze VIC proceeding** |
| D-70 | **MOYSA, N.** – Letter dated October 14, 2005 requesting Interested Party Status<br><br>***Previously D-2 in Sea Breeze VIC proceeding** |
| D-71 | Letter of Comment dated December 6, 2005 from the Bonneville Power Administration<br><br>***formerly Exhibit E-19** |
| D-72 | Letter of Comment dated December 20, 2005 from the City of Surrey – Paul Ham, P.Eng., General Manager, Engineering Dept |
| D-73 | Web registration dated February 28, 2005 requesting Interested Party Status from Janet Williams |
| D-73-1 | Letter of Comment received by fax February 28, 2006 from Janet Williams |
| D-74 | Web registration dated March 21, 2006 requesting Interested Party status from Phil Le Good |

### LETTERS OF COMMENT

| Exhibit No. | Description |
|---|---|
| E-1 | Letter of Comment dated June 3, 2005 from Sheila Harrington |
| E-2 | Letter of Comment dated February 21, 2005 from Claudia Jesson, Corporation of Delta |
| E-3 | Letter of Comment dated February 21, 2005 from Neil Atchison and Cecil Dunn, Tsawwassen Residents Against Higher Voltage Overhead Lines |
| E-4 | Response letter dated April 1, 2005 from Honourable Richard Neufeld, Minister, to Letter of Comment from Wendy and Bob Childs |
| E-5 | Letter of Comment dated April 5, 2005 from Tony Law, Island Trust Council |
| E-6 | Letter of Comment dated April 10, 2005 from Ted Bishop |
| E-6-1 | Pending – submission at Salt Spring Town Hall Meeting |

| Exhibit No. | Description |
|---|---|
| E-7 | Letter of Comment dated July 28, 2005 from Foster W. Richardson and M.A. Richardson |
| E-8 | Letter of Comment dated July 28, 2005 from Hans L. a Delta resident |
| E-9 | Letter of Comment dated July 28, 2005 from Ann Gardner and M.J. L. Gardner |
| E-10 | Letter of Comment dated July 28, 2005 from Sonja Whitehead and P. Leah |
| E-11 | Letter of Comment dated August 4, 2005 from Lorraine Baker |
| E-12 | Letter of Comment dated August 5, 2005 from Mrs. I.A. Jackson |
| E-13 | Letter of Comment received August 10, 2005 from Edward A. Kenmare |
| E-14 | Letter of Comment dated August 5, 2005 from Mr. & Mrs. R.I. Holder |
| E-15 | Letter of Comment dated October 21, 2005 from Roger Santini |
| E-16 | **BERG, Richard** - E-mail dated November 3, 2005 – Letter of Comment E-mail dated November 3, 2005 from Richard Berg<br><br>Emails dated November 3, 2005 between Terry Treasure & Richard Berg<br><br>***Previously E-1 in Sea Breeze VIC proceeding** |
| E-16-1 | **BERG, Richard** - Email dated February 1, 2006 Letter of Comment to the Honourable Gordon Campbell, Premier, regarding the privatization of transmission lines |
| E-16-2 | **BERG, Richard** - Email dated February 1, 2006 Letter of Comment to BCTC's Donna McGeachie forwarded to BCUC regarding replacement of transmission lines |
| E-16-3 | **BERG, Richard** - Email dated February 1, 2006 Letter of Comment regarding official governmental policy and role of BCUC |
| E-17 | Letter of Comment dated November 30, 2005 – Article from The Delta Optimist Newspaper from Maureen Broadfoot for the SDSHS |
| E-18 | Letter of Comment dated December 5, 2005 – Article from the Delta Optimist Newspaper from Maureen Broadfoot<br><br>**WITHDRAWN – replaced with Exhibit C40-7** |

| Exhibit No. | Description |
|---|---|
| E-19 | Letter of Comment dated December 6, 2005 from the Bonneville Power Administration<br><br>***Reassigned as Exhibit D-71** |
| E-20 | Letter of Comment dated December 7, 2005 from Mr. Don Bruchet |
| E-21 | Letter dated December 16, 2005 from the District of Saanich, Engineering Department to Sea Breeze Pacific Regional Transmission System, Inc. |
| E-22 | Letter of Comment from Shannon Cannon |
| E-23 | Letter of Comment dated January 2, 2006 from Don & Karen Parry |
| E-24 | Letter of Comment dated December 30, 2005 from the Esquimalt Chamber of Commerce signed by Marilyn Holder, Director |
| E-25 | Letter of Comment dated January 5, 2006 from Glenda Bartosh, White Rock |
| E-26 | Letter of Comment submission at Salt Spring Town Hall Meeting from the Raging Grannies |
| E-27 | Letter of Comment submission at Salt Spring Town Hall Meeting from Kim Hoban |
| E-28 | Pending – submission at Salt Spring Town Hall Meeting |
| E-29 | Letter of Comment submission at Salt Spring Town Hall Meeting from resident |
| E-30 | Letter of Comment submission at Salt Spring Town Hall Meeting from K. Linegen |
| E-31 | Letter of Comment submission at Salt Spring Town Hall Meeting from Chris Anderson |
| E-32 | Letter of Comment submission at Salt Spring Town Hall Meeting from resident |
| E-33 | Letter of Comment submission at Salt Spring Town Hall Meeting from Dr. Angela Dedye, Ph.D. |
| E-34 | Letter of Comment submission at Salt Spring Town Hall Meeting from John Steel |
| E-35 | Letter of Comment submission at Salt Spring Town Hall Meeting from Margaret Briggs |

| Exhibit No. | Description |
|---|---|
| E-36 | Letter of Comment submission at Salt Spring Town Hall Meeting from David Denning |
| E-37 | Letter of Comment submission at Salt Spring Town Hall Meeting from Gary Brady |
| E-38 | Letter of Comment submission at Salt Spring Town Hall Meeting from Jean Collins |
| E-39 | Letter of Comment submission at Salt Spring Town Hall Meeting from Katharina Gustavs |
| E-40 | Letter of Comment submission at Salt Spring Town Hall Meeting from Elizabeth White |
| E-41 | Letter of Comment submission at Salt Spring Town Hall Meeting from Deborah Cran |
| E-42 | Letter of Comment submission at Salt Spring Town Hall Meeting from John Quinn |
| E-43 | Letter of Comment submission at Salt Spring Town Hall Meeting from Erin Porter |
| E-44 | Letter of Comment submission at Salt Spring Town Hall Meeting from Larry Wolfe |
| E-45 | Letter of Comment submission at Salt Spring Town Hall Meeting from Aaron Sigargeirson |
| E-46 | Letter of Comment dated January 12, 2006 from the White Rock Ratepayers Association |
| E-46-1 | Letter of Comment dated January 9, 2006 from the White Rock Ratepayers Association regarding the VITR-VIC hearing process |
| E-47 | Letter of Comment dated December 30, 2006 from the Town of Sidney, Robert J.W. Hall, Director of Engineering and Works to Sea Breeze Pacific Regional Transmission System |
| E-48 | Letter of Comment dated January 8, 2006 from Derek & Karen Lorimer |
| E-49 | Submission at Tsawwassen Town Hall Meeting by Wendy Jeske |
| E-50 | Submission at Tsawwassen Town Hall Meeting by Cecil Dunn & Family |
| E-51 | Submission at Tsawwassen Town Hall Meeting by Deborah McBride |

| Exhibit No. | Description |
|---|---|
| E-52 | Submission at Tsawwassen Town Hall Meeting by F. Weisser |
| E-53 | Submission at Tsawwassen Town Hall Meeting by Glen Page |
| E-54 | Submission at Tsawwassen Town Hall Meeting by Agnes Jackson |
| E-55 | Submission at Tsawwassen Town Hall Meeting by Rocio Gonzalez |
| E-56 | Submission at Tsawwassen Town Hall Meeting by Michael John Winfield |
| E-57 | Submission at Tsawwassen Town Hall Meeting by Bernadette Kudzin |
| E-58 | Submission at Tsawwassen Town Hall Meeting by Douglas George Masey |
| E-59 | Submission at Tsawwassen Town Hall Meeting by Andrew Bak |
| E-60 | Submission at Tsawwassen Town Hall Meeting by Doug Adams |
| E-61 | Submission at Tsawwassen Town Hall Meeting by Shelley Willms |
| E-62 | Submission at Tsawwassen Town Hall Meeting by Unknown Presenter |
| E-63 | Submission at Tsawwassen Town Hall Meeting by Joedi Timmons |
| E-64 | Submission at Tsawwassen Town Hall Meeting by John Noble |
| E-65 | Submission at Tsawwassen Town Hall Meeting by Unknown Presenter |
| E-66 | Submission at Tsawwassen Town Hall Meeting by Mark Robinson |
| E-67 | Submission at Tsawwassen Town Hall Meeting by M. Dietrich |
| E-68 | Submission at Tsawwassen Town Hall Meeting by Unknown Presenter |
| E-69 | Letter of Comment dated January 14, 2006 from Jim Ormesher |
| E-70 | Letter of Comment dated January 16, 2006 from Dale Evoy |
| E-71 | Letter of Comment dated January 16, 2006 from Leona Gom |
| E-72 | Letter of Comment dated January 16, 2006 from Elizabeth Kearns |
| E-73 | Letter of Comment dated January 16, 2006 from Lynne Schroder |
| E-74 | Letter of Comment dated January 18, 2006 from Genevieve Loslier and Thomas Gessell |
| E-75 | Letter of Comment dated January 18, 2006 from Lynne Sinclair |

| Exhibit No. | Description |
|---|---|
| E-76 | Letter of Comment dated January 18, 2006 from John and Patricia Samson |
| E-77 | Letter of Comment dated January 19, 2006 from Fiona Old |
| E-78 | Letter of Comment dated January 24, 2006 from Randy Sigouin |
| E-79 | Letter of Comment dated January 28, 2006 from J.E. McIlvenna |
| E-80 | Letter of Comment dated January 28, 2006 from Robert Odynski |
| E-81 | Letter of Comment received January 31, 2006 from Mary and J. Person |
| E-82 | Letter of Comment received January 31, 2006 from Anonymous |
| E-83 | Letter of Comment dated January 28, 2006 from Cham Cheong Yuen |
| E-84 | Letter of Comment received January 31, 2006 from Varena Blatter |
| E-85 | Letter of Comment received January 31, 2006 from H. I. Dye |
| E-86 | Letter of Comment dated January 29, 2006 from David Adamson |
| E-87 | Letter of Comment received January 31, 2006 from E. A. Old |
| E-88 | Letter of Comment received February 1, 2006 from Joelle Tiessen |
| E-89 | Letter of Comment received February 2, 2006 from Janice Smith |
| E-90 | Letter of Comment received February 1, 2006 from Roger Poissent and Debbie Norrish |
| E-91 | Letter of Comment received February 1, 2006 from Mr. & Mrs. R. Kocher |
| E-92 | Letter of Comment received February 1, 2006 from Bill Cron |
| E-93 | Letter of Comment received February 1, 2006 from Lorraine Hand |
| E-94 | Letter of Comment received February 1, 2006 from Anonymous |
| E-95 | Letter of Comment received February 3, 2006 from June and Vern Dubay |
| E-96 | Letter of Comment received February 3, 2006 from Mr. & Mrs. E. Duck |
| E-97 | Letter of Comment received February 3, 2006 from Diane Pauker |
| E-98 | Letter of Comment received February 3, 2006 from Mr. & Mrs. A. Visone |

| Exhibit No. | Description |
|---|---|
| E-99 | Letter of Comment received February 3, 2006 from Gabrielle Visone |
| E-100 | Letter of Comment dated February 4, 2006 from Peter & Gail Taylor |
| E-101 | Letter of Comment dated February 5, 2006 from Ray Skelly |
| E-102 | Letter of Comment received February 3, 2006 from Pieter Vlek |
| E-103 | Letter of Comment received February 6, 2006 from Jean-Claude Castex |
| E-104 | Letter of Comment received February 6, 2006 from the Watson Family |
| E-105 | Letter of Comment received February 6, 2006 from Sarah Blane |
| E-106 | Letter of Comment received February 6, 2006 from Eric Schmidt |
| E-107 | Letter of Comment received February 7, 2006 from Jim Davidson and Carmen Froment |
| E-108 | Letter of Comment received February 7, 2006 from Thomas Haworth |
| E-109 | Letter of Comment received February 7, 2006 from Keith Stirling |
| E-110 | Letter of Comment received February 7, 2006 from Sharon & Douglas Muche |
| E-111 | Letter of Comment received February 7, 2006 from Beverley Cunningham |
| E-112 | Letter of Comment received February 7, 2006 from Colin & Muriel Mason |
| E-113 | Letter of Comment received February 7, 2006 from Ben Dirksen |
| E-114 | Letter of Comment dated February 8, 2006 from Kristen Sheehan |
| E-115 | Letter of Comment received February 8, 2006 from Joan Coulas |
| E-116 | Letter of Comment received February 8, 2006 from Susan and Brian Lamont |
| E-117 | Letter of Comment received February 8, 2006 from Ezio Cividino |
| E-118 | Letter of Comment received February 8, 2006 from Carl and Sandra Olafson |
| E-119 | Letter of Comment received February 8, 2006 from Marie-France Hautberg |
| E-120 | Letter of Comment received February 8, 2006 from A. Lewis |
| E-121 | Letter of Comment received February 8, 2006 from Jim Diemer |

| Exhibit No. | Description |
|---|---|
| E-121-1 | Letter of Comment received March 9, 2006 from Jim Diemer |
| E-122 | Letter of Comment dated February 9, 2006 from Ra & Deborah McGuire |
| E-123 | Letter of Comment dated February 9, 2006 from Peter & Leora Shipley |
| E-124 | Letter of Comment dated February 6, 2005 from Edith & Helmut Kraemer opposing the 550 Mega Watt Cable planned through South Surrey - White Rock |
| E-125 | Letter of Comment from an Anonymous resident received February 9, 2006 |
| E-126 | Letter of Comment received February 9, 2006 from Gail & Dave Annets |
| E-127 | Letter of Comment received February 10, 2006 from Gladys M. Rai |
| E-128 | Letter of Comment dated February 8, 2006 from William S. Morton |
| E-129 | Petition received February 10, 2006 from William Morton and Home Owners/Residents opposed to the proposed HVDC-light, City of White Rock Route |
| E-130 | Letter of Comment received February 14, 2006 from Bhupinder Singh Sidhu |
| E-131 | Letter of Comment received February 13, 2006 from Scott and Barbara Guest |
| E-132 | Letter of Comment received February 13, 2006 from Maureen & Robin Harrison |
| E-133 | Letter of Comment received February 13, 2006 from Rolf and Julie Wagner |
| E-134 | Letter of Comment received February 13, 2006 from April Rohee |
| E-135 | Letter of Comment received February 13, 2006 from Anonymous |
| E-136 | Letter of Comment received February 13, 2006 from N. & S. Ghislieri |
| E-137 | Letter of Comment received February 13, 2006 from Debra Swain |
| E-138 | Letter of Comment received February 15, 2006 from Paula Ryan |
| E-139 | Letter of Comment received February 15, 2006 from A.J. & V.M. Nicholson |
| E-140 | Letter of Comment received February 15, 2006 from Curtis Murray |
| E-141 | Letter of Comment received February 16, 2006 from Dori Brown |

| Exhibit No. | Description |
|---|---|
| E-142 | Letter of Comment received February 16, 2006 from Linda Carvajal |
| E-143 | Letter of Comment received February 16, 2006 from Bruce McLeod |
| E-144 | Letter of Comment received February 19, 2006 from Tonja Steiner |
| E-145 | Letter of Comment received February 18, 2006 from Karen Cunha |
| E-146 | Letter of Comment received February 20, 2006 from Daphne Buchanan |
| E-147 | Letter of Comment received February 20, 2006 from Laura and Russell Kearnes |
| E-148 | Letter of Comment received February 20, 2006 from Patricia L. (Buchanan) Randall |
| E-149 | Letter of Comment received February 21, 2006 from Tanesa Kiso |
| E-150 | Letter of Comment received February 21, 2006 from Paul Felker |
| E-151 | Letter of Comment received February 21, 2006 from Greg and Kelly Dombroski |
| E-152 | Letter of Comment received February 21, 2006 from David Souter |
| E-153 | Letter of Comment received February 21, 2006 from Annette Zacher |
| E-154 | Letter of Comment received February 22, 2006 from Robert Anderson |
| E-155 | Letter of Comment received February 22, 2006 from Robert and JoAnne Lemieux |
| E-156 | Letter of Comment received February 21, 2006 from Ingrid Diles |
| E-157 | Letter of Comment received February 17, 2006 from Maureen Hansen |
| E-158 | Letter of Comment received February 22, 2006 from Seth Wass |
| E-159 | Letter of Comment received February 22, 2006 from William S. Morton |
| E-159-1 | Letter of Comment received February 24, 2006 from William S. Morton |
| E-160 | Letter of Comment received February 22, 2006 from Karen Haugland |
| E-161 | Letter of Comment received February 22, 2006 from Jan Kristiansen |
| E-162 | Letter of Comment received February 22, 2006 from Liz Barak |

| Exhibit No. | Description |
|---|---|
| E-163 | Letter of Comment received February 22, 2006 from Cathy Potkins |
| E-164 | Letter of Comment received February 22, 2006 from Valerie Mair |
| E-165 | Letter of Comment received February 23, 2006 from Jeff Hubbick |
| E-165-1 | Letter of Comment emailed February 27, 2006 from Jeff Hubbick |
| E-166 | Letter of Comment received February 23, 2006 from Christine Kearnes |
| E-167 | Letter of Comment received February 23, 2006 from Wayne Bourgeois |
| E-168 | Letter of Comment received February 23, 2006 from Irene L. Olson |
| E-169 | Letter of Comment emailed February 25, 2006 from Diane Bradley |
| E-170 | Letter of Comment emailed February 27, 2006 from Betty Jo Gillett |
| E-171 | Letter of Comment emailed February 26, 2006 from Tom & Lucy Seidelmann |
| E-172 | Letter of Comment emailed February 25, 2006 from Richard Wiklo and Nancy Walton |
| E-173 | Letter of Comment received February 27, 2006 from R. J. Ralston |
| E-174 | Letter of Comment emailed February 27, 2006 from Bonnie-Jayne Errett |
| E-175 | Letter of Comment emailed February 28, 2006 from DJ@telus.net |
| E-176 | Letter of Comment emailed February 28, 2006 from Darlene Rodocker |
| E-177 | Letter of Comment emailed February 28, 2006 from Gillian Caldwell |
| E-178 | Letter of Comment emailed February 28, 2006 from Dr. John D. Welch |
| E-179 | Letter of Comment emailed February 28, 2006 from William K. Tower |
| E-180 | Letter of Comment emailed February 28, 2006 from Roger Poissenot and Debbie Norrish |
| E-181 | Letter of Comment emailed February 28, 2006 from Prof. David MacAlister |
| E-182 | Letter of Comment emailed February 28, 2006 from D. Gibala |
| E-183 | Letter of Comment emailed February 28, 2006 from Judy Hale |

| Exhibit No. | Description |
|---|---|
| E-185 | Letter of Comment received March 1, 2006 from Guy Gentner, MLA, North Delta |
| E-186 | Letter of Comment received March 2, 2006 from Robert Lee Taylor and Sonja Taylor |
| E-187 | Letter of Comment received February 28, 2006 from Ministry of Environmental Assessment Office responding to IRAHVOL |
| E-188 | Letter of Comment received March 2, 2006 from Gordon Hogg, MLA, Surrey-White Rock |
| E-189 | Letter of Comment dated March 2, 2006 from Leslie Cummings, Surrey |
| E-190 | Letter of Comment received March 1, 2006 from Judith Hampson, White Rock |
| E-191 | Letter of Comment dated March 2, 2006 from Anne Wallace |
| E-192 | Letter of Comment dated March 2, 2006 from Darrin Lane, White Rock |
| E-193 | Letter of Comment dated March 3, 2006 from Tenzin White |
| E-194 | Letter of Comment dated March 3, 2006 from Linda and Tom Spragge |
| E-195 | Letter of Comment dated March 3, 2006 from Kimberlea Murphy |
| E-196 | Petition received March 7, 2006 from Valerie M. Mair |
| E-197 | Letter of Comment received March 8, 2006 from Tracy Farden |
| E-198 | Letter of Comment received March 10, 2006 from George Plant |
| E-199 | Letter of Comment received March 17, 2006 from Marilyn & Ian Holder |
| E-200 | Letter of Comment emailed March 17, 2006 from Phil Le Good |
| E-201 | Letter of Comment emailed March 18, 2006 from William K. Tower |