FARRIS

25th Floor
700 W Georgia St | Vancouver, BC
Canada V7Y 1B3 | Tel 604 684 9151
Fax 604 661 9349 | www.farris.com

Reply Attention of: Erica C. Miller
Direct Dial Number: (604) 661-9328
Email Address: emiller@farris.com

Our File No.: 05497-0244

November 14, 2016

BY EMAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Inc. Application for a Certificate of Public Convenience and Necessity for the Replacement of the Corra Linn Dam Spillway Gates

Enclosed please find the Final Submissions of FortisBC Inc. dated November 14, 2016 with respect to the above-noted matter. Five hard copies will follow by courier.

Please also find enclosed three legal authorities, which are referenced in the Final Submission.

Yours truly,

FARRIS, VAUGHAN, WILLS & MURPHY LLP

Per: EMiller

Erica C. Miller

ECM/ch
Enclosure
c.c.: Registered Interveners
FortisBC Inc.

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

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the *Utilities Commission Act,*
R.S.B.C. 1996, Chapter 473 (the "*Act*")

and

An Application by FortisBC Inc.

for a Certificate of Public Convenience and Necessity for Replacement of the Corra Linn Dam Spillway Gates

FINAL SUBMISSIONS OF

FORTISBC INC.

November 14, 2016

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PART One: OVERVIEW

1. On June 29, 2016, FortisBC Inc. (**FBC** or the **Company**) filed an application (the **Application**) with the British Columbia Utilities Commission (**BCUC** or the **Commission**) for a Certificate of Public Convenience and Necessity (**CPCN**) for the construction and operation of fourteen replacement spillway gates and upgrades to certain of the components of the associated structures at the Corra Linn Dam (the **Project**).

2. The key driver for the Project arises from recent amendments made to Canadian dam industry standards and British Columbia government regulations, which have resulted in the Corra Linn Dam being reclassified to an "extreme" consequence classification, and hence no longer complying with the regulated requirements. The reclassification of the Corra Linn Dam is due to the risk of loss of life in excess of 100 persons to a permanent population residing downstream of the dam. Dams with an "extreme" classification are required to withstand a specific "design earthquake" and "design flood", and studies have determined that the Corra Linn Dam spillway gates and certain components of the associated structures are not presently able to withstand the "design earthquake" event. Accordingly, it has been determined that the spillway gates will require either substantial rehabilitation or replacement in order to satisfy industry standards and government regulations.

3. An additional driver for the Project is that the current spillway gates are 84 years old, and recent inspections have assessed the gates as being only in "fair to poor condition" and approaching end of life.

4. The Company identified four alternatives to bring the spillway gates into compliance with the regulated requirements: Alternative 1: Do Nothing, Alternative 2: Deferral, Alternative 3: Gate Refurbishment, and Alternative 4: Gate Replacement. Ultimately, only Alternative 4 was found to satisfy all the technical criteria of the Project, which sought to have the spillway gates withstand the design earthquake (including remaining operational following the design earthquake), withstand the design flood, minimize Project risks, and maximize the reliability of the spillway gates and associated equipment. Alternative 3 largely satisfied these technical criteria (aside from failing to minimize Project

risks). As Alternative 1 and Alternative 2 failed to satisfy any of the criteria, they were found to be not feasible and eliminated from further consideration.[1]

5. As between Alternative 3 and Alternative 4, FBC assessed which option would minimize the customer financial impacts resulting from the Project. While the initial capital costs of Alternative 4 (Gate Replacement) would be approximately $2.9 million more expensive then Alternative 3 (Gate Refurbishment), $62.694 million versus $59.784 million (as spent),[2] the long term financial impact of Alternative 3 increases when the future, necessary replacement of the existing spillway gates are taken into account. If the existing spillway gates are required to be replaced by 2032 (when the existing gates reach 100 years of age), the financial impact of Alternative 3 would be approximately $21 million more than Alternative 4 (Gate Replacement).[3] Even if the lifespan of the current spillway gates can be extended for a full 25 years following refurbishment, Alternative 3 would be approximately $10 million more than Alternative 4.[4]

6. Based on the technical and financial assessments of the Alternatives, FBC has selected Alternative 4 (Gate Replacement) as the preferred alternative for the Project. It has set out in detail in the Application, the steps to be taken to implement the Project utilizing this alternative. As noted previously, the total initial capital cost of the Project is expected to be $62.694 million (as spent). The impact to customer rates is an approximate increase of 1.49% over the 2016 approved Revenue Requirements, when all assets have entered into rate base in 2022, or an approximate bill increase of $1.83 per month for a residential customer consuming an average of 991 kWh per month. Over a 70 year analysis period, the levelized rate impact to customers is an increase of approximately 1.46%.[5]

7. On July 8, 2016, pursuant to Order G-107-16, the Commission established a written public hearing process and a Regulatory Timeline for the Application.[6]

8. The written record in this proceeding is extensive and includes the Application (in two parts, the Application at Exhibit B-1 with Appendices, and Exhibit B-1-1 with Confidential Appendices) and two rounds of Information Requests.

1 Ex. B-1, Application, s. 4.
2 Ex. B-1, Application, s. 4.3.2, at p. 36.
3 Ex. B-1, Application, s. 4.3.2, at p. 37.
4 Ex. B-1, Application, s. 4.3.2, at p. 37; Ex. B-3, BCUC IR 1.4.2.2.
5 Ex. B-3. BCUC IR 1.6.1, at pp. 33-34.
6 Order G-107-16, p. 2 and Appendix A.

9. It is respectfully submitted that the evidentiary record, including FBC's Application, Appendices, and its responses to Information Requests, confirms that the orders the Company seeks should be granted. While this Final Submission summarizes key points, FBC relies on the evidentiary record as a whole.

10. For ease of reference, the remainder of this Final Submission is organized as follows:

a. Part II – the CPCN Test;

b. Part III – the Corra Linn Dam;

c. Part IV - Project Justification;

d. Part V – Alternatives Considered;

e. Part VI – Project Description;

f. Part VII – Project Cost Estimate;

g. Part VIII – Public and First Nations Consultation; and

h. Part IX – Conclusion.

PART Two: THE CPCN TEST

11. FBC seeks approval of this Application for a CPCN pursuant to sections 45 and 46 of the *Utilities Commission Act*, RSBC 1996, c 473 (the **UCA**). The Application meets the statutory criteria and those which have been applied by the Commission in determining CPCN applications.

A. THE CPCN & PBR MATERIALITY THRESHOLD

12. As is described later in this Final Submission, the Project has an estimated capital cost of approximately $62.694 million.[7]

13. As the estimated capital cost are over the CPCN dollar threshold of $20 million, the Company is applying to the Commission for a CPCN for the Project.[8]

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[7] Ex. B-1, Application, s. 6.3.1, at p. 59.

14. The estimated capital cost are also over the PBR materiality threshold of $20 million, meaning that the Project is to be excluded from the PBR formula-driven spending envelope.[9] FBC confirms that none of the costs included in the Project's estimated capital cost arise from work that would normally be undertaken within the formula capital expenditures or the formula O&M expense under the PBR mechanism.[10]

15. The Company confirms that the Project is one single project, and that it is not the result of combining several smaller projects.[11]

B. FINANCIAL & TECHNICAL CAPACITY FOR THE PROJECT

16. As is set out in more detail in Section 2 of the Application, FBC confirms that it has both the financial and technical capacity to complete the Project.

17. With respect to financial capacity, FBC is capable of financing the Project either directly or through its parent FortisBC Pacific Holdings Inc. FBC has credit ratings for senior unsecured debentures from DBRS and Moody's Investors Service of A (low) and Baa1, respectively.[12]

18. With respect to technical capacity, the Company has considerable experience in the overall management of a number of large hydroelectric rehabilitation and upgrade projects. FBC will provide the necessary resources to manage the execution of the Project.[13] In addition, FBC plans to supplement its internal resources by ensuring that a reputable contractor with specialized experience in the design, supply and installation of spillway gate systems is used for the construction of the Project, and by retaining a knowledgeable Owner's Engineer that is familiar with the design of spillway gate systems.[14]

C. THE PROJECT IS IN THE PUBLIC CONVENIENCE AND NECESSITY

19. Section 45(1) of the UCA provides:

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8 Pursuant to the FBC's PBR Application (approved by Order G-139-14) and the Capital Exclusion Criteria (approved by Order G-120-15), the Commission set both the CPCN dollar threshold and the PBR materiality threshold at $20 million.
9 Ex. B-1, Application, s. 1.4.1, at p. 5.
10 Ex. B-5, CEC IR 1.3.1, at p. 7.
11 Ex. B-1, Application, s. 1.4.1, at p. 5.
12 Ex. B-1, Application, s. 2.2, at p. 8.
13 Ex. B-1, Application, s. 2.2, at p. 8.
14 Ex. B-1, Application, s. 2.3, at p. 9.

Certificate of public convenience and necessity

> **45**(1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

20. Pursuant to section 45(8) of the UCA, in order for the Commission to approve an application for a CPCN, it must first be satisfied that it is "necessary for the public convenience and properly conserves the public interest".

21. While section 45(8) of the UCA requires the proposed Application to be both "necessary for the public convenience" and to conserve the "public interest", these two phrases have been held to be synonymous with each other, rather than creating two distinct requirements that must each be satisfied.[15] The Commission 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".[16]

22. The UCA itself does not provide a definition or further explanation on when a project will be "necessary for public convenience" or in "the public interest". Instead, the BCUC has been found to have a broad discretion to consider a variety of factors and evidence. The test has been described as a "flexible test" where the Commission is able to consider and weigh a "broad range of interests".[17]

23. While the relevant factors to consider under sections 45 and 46 of the UCA will vary with each application, in the circumstances of this Application, the pertinent public interest concerns that the Commission should consider with respect to the Project include the (a) need for the refurbishment or replacement of the spillway gates and associated structures in order to satisfy industry standards and regulations; (b) need for the refurbishment or replacement to mitigate the risk of dam failure, and the associated consequences to downstream populations, the environment and infrastructure; (c) reliability of service of the spillway gates and the Corra Linn Dam; (d) operational effectiveness of the spillway gates and associated equipment; (e) cost effectiveness of the Project; (e) rate impact of the Project; (f) customer benefits, and (g) socio-economic consideration (including any positive or negative environmental, safety or community impacts).

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15 *Emera Brunswick Pipeline Co. (Re)*, 2007 LNCNEB 3 at para. 43.

16 Re British Columbia Transmission Corporation, An Application for a Certificate of Public Convenience and Necessity for the Vancouver Island Transmission Reinforcement Project, July 7, 2006 (the **VITR Decision**), at p. 15 and *Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co*., [1958] S.C.R. 353, 1958 CanLII 82 at para. 9.

17 The VITR Decision, at p. 15.

24. The Project satisfies each of these criteria.

D. SECTION 46(3.1) OF THE UCA

25. Section 46 (3.1) of the UCA requires the Commission to consider the following in determining 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;
>
> (c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*.

I. BRITISH COLUMBIA'S ENERGY OBJECTIVES

26. With respect to section 46(3.1)(a), British Columbia's energy objectives are provided in section 2 of the *Clean Energy Act* (**CEA**). FBC was mindful of these energy objectives when designing the Project and the following objectives were identified as being applicable to the present Application:

> (a) to achieve electricity self-sufficiency;
>
> ...
>
> (c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
>
> ...
>
> (g) to reduce BC greenhouse gas emissions…;
>
> ...
>
> (k) to encourage economic development and the creation and retention of jobs;
>
> ...
>
> (m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia.[18]

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[18] Ex. B-1, Application, s. 8, at p. 68.

27. The Corra Linn Dam is integral in supplying clean, renewable hydroelectric power in British Columbia, and ensuring that the spillway gates continue to be operational and safe is important to the overall operation of the dam. The Project therefore contributes to FBC achieving electricity self-sufficiency, the generation of clean or renewable energy in BC, the reduction of greenhouse gas emissions for alternative energy sources, and maximizing the value of BC's clean energy generation assets. In addition, the implementation of the Project and the associated construction will create jobs, encouraging economic development in the province.[19]

II. Long Term Strategy

28. Under section 46(3.1)(b), the Commission must consider the most recent long-term resource plan filed by the public utility.

29. The Project was identified in section 2.5.1.5 of FBC's 2012 Long-Term Capital Plan (the **2012 LTCP**),[20] which was filed alongside FBC's 2012 Long-Term Resource Plan (the **2012 LTRP**), as part of the Company's Integrated System Plan. The LTCP identified the Project as being a "major" capital project to be completed.[21] The Project is also consistent with the 2012 LTRP, which relied upon ongoing generation from all of FBC's generating assets, including the Corra Linn Dam. The 2012 LTCP and 2012 LTRP were accepted by the Commission in Order G-110-12.[22]

30. The Project was also identified as an anticipated CPCN application in FBC's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (**PBR Application**), which was approved by Order G-139-14.[23]

III. Sections 6 and 19 of the CEA

31. Finally, section 46(3.1)(c) of the UCA requires the Commission to consider the extent to which the Application is consistent with the applicable requirements in sections 6 and 19 of the CEA. None of the requirements in section 6 and 19 of the CEA are applicable to the Project, specifically:

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[19] Ex. B-1, Application, s. 8, at p. 68.
[20] The Project was referred to as the "Corra Linn Spillgate and Spillway Concrete Rehabilitation Project" in the 2012 Long Term Capital Plan.
[21] Ex. B-1, Application, s. 8, at p. 68.
[22] Order G-110-12, FBC's 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan. The Project is identified as the "Corra Linn Spillgate and Spillway Concrete Rehabilitation Project" at Ex. B-1, Application, Vol 1. – Long Term Capital Plan, at pp. 54-55.
[23] Order G-139-14, FBC's 2014-2018 Multi-Year Performance Based Ratemaking Plan. The Project is identified at Ex. B-1, Application, s. 5.4.2.2.

a. section 6(1) through (3) only apply to the "authority", which is defined as being BC Hydro;

b. section 6(4) requires a public utility to consider British Columbia's energy objectives in planning for "the construction or extension of generation facilities and energy purchases" in terms of its long-term resource plan. The Project will not result in new generation or energy purchases and it is not being driven by the generating capacity of the Corra Linn Dam;[24] and

c. section 19 applies to the authority, prescribed utilities and classes of prescribed public utilities, none of which apply to FBC.

PART Three: THE CORRA LINN DAM

32. The Corra Linn Dam is the uppermost dam in a series of four FBC-owned dams on the Kootenay River, located approximately 15 kilometres downstream from the city of Nelson, BC. The aggregate capacity of these four dams is 225 megawatts,[25] with the Corra Linn Dam having a current generating capacity of 49.45 MW.[26]

33. The Corra Linn Dam was commissioned in 1932, and has now been in operation for 84 years.[27] The Corra Linn Dam is a concrete mass gravity structure, and FBC considers the concrete structure to be in generally good condition.[28] The Corra Linn Dam is comprised of five sections: the east dam, the spillway, the middle dam, the powerhouse and the associated headworks.[29]

34. Of most relevance to the present Application is the spillway section of the Corra Linn Dam. It is comprised of fourteen identical spillway gates, each approximately ten metres wide by ten metres high. The gates are supported by a steel superstructure, which consists of sixteen bridges and seventeen towers. The spillway gates are raised (opened) and lowered (closed) using two electrically operated travelling screw hoists, which travel along the length of the superstructure to reach each of the gates.[30] A figure showing the spillway section of the Corra Linn Dam, including six spillway gates may be seen at Figure 3-4 of the Application.[31]

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24 Ex. B-3, BCUC IR 1.1.1, at p. 2.
25 Ex. B-1, Application, s. 3.1.1 at p. 10.
26 Ex. B-3, BCUC IR 1.1.1 at p. 3.
27 Ex. B-1, Application, s. 3.1.1 at p. 10, and s. 3.1.2 at p. 13.
28 Ex. B-3, BCUC IR 1.4.3 at p. 26.
29 Ex. B-1, Application, s. 3.1.1 at p. 10.
30 Ex. B-1, Application, ss. 3.1.2, 3.1.3 and 3.1.4 at p. 13.
31 See Ex. B-1, Application, Figure 3-4 at p. 14.

35. It is the raising and lowering of the spillway gates that regulates water flow at the Corra Linn Dam, maintaining the water levels in the Kootenay Lake reservoir. While the reservoir is shared by the Corra Linn Dam with the adjacent Kootenay Canal Generating Station (which is owned by BC Hydro), the Kootenay Canal Generating Station has no ability to spill water. As a result, in addition to being critical to the operation of the Corra Linn Dam itself, the Corra Linn Dam spillway gates and associated facilities are essential for the safe operation of the Kootenay Lake reservoir.[32] The importance of the spillway gates was further explained in section 3.1.2 of the Application, as follows:

> The Corra Linn Dam spillway gate facilities are critical for the safe operation of the reservoir and dam and provide an essential means for controlling reservoir levels. The gates are also used to release water to safely lower the reservoir in a controlled manner when high flow conditions occur. The ability of the gates to safely pass this water to lower the reservoir level in a controlled manner, while simultaneously providing a barrier to retain water, is dependent on the reliability and the structural capacity of the gates. Assuring that the gates maintain their capacity under all reasonably foreseeable scenarios not only protects the dam itself, but also prevents potential negative effects on the downstream population, environment and infrastructure.[33]

PART Four: PROJECT JUSTIFICATION

36. This section of FBC's Final Submission summarizes the primary drivers for the Project.[34]

37. First, as is set out below in more detail, there have recently been changes in the industry standards and government regulations that apply to dams in British Columbia. This has resulted in the Corra Linn Dam being reclassified as having an "extreme" consequence classification, which is a measure of the severity of the possible consequences if the Corra Linn Dam were to fail. Given the severity of the potential consequences of a failure, the Corra Linn Dam must be able to withstand a certain magnitude "design earthquake" and "design flood". As is explained below, recent assessments and studies performed by HMI Construction Inc. (**HMI**) have determined that the spillway gates and certain of the components of the associated equipment do not presently have the strength to withstand the design earthquake, and they therefore require replacement or substantial rehabilitation to comply with industry standards and regulation.

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[32] Ex. B-1, Application, s. 3.1.1 at p. 10.
[33] Ex. B-1, Application, s. 3.1.2, at p. 13.
[34] See also Ex. B-1, Application, s. 3 for additional details on the key drivers for the Project.

38. Additionally, the Corra Linn Dam is 84 years, and the spillway gates are approaching end of life. Recent inspections of three of the spillway gates, the steel superstructure and the gate hoists have confirmed that the spillway gates are presently in fair to poor condition.

A. RECENT CHANGES IN INDUSTRY STANDARDS & REGULATIONS

39. Since 2007, there have been several changes to the industry standards and regulations that apply to dams in British Columbia, specifically with respect to:

a. the Canadian Dam Association Dam Safety Guidelines (**CDSG**); and

b. the BC Dam Safety Regulation (**BCDSR**).

40. These changes, and the resulting impact on the Corra Linn Dam, are discussed next.

I. THE CANADIAN DAM ASSOCIATION DAM SAFETY GUIDELINES (CDSG)

41. The CDSG is published by the Canadian Dam Association[35] and sets out the industry standards for dams within Canada. It establishes the "Dam Consequence Classification", which is a system for classifying Canadian dams into categories, based on the severity of the consequences of the dam's failure. Depending on the consequence classification, the CDSG defines a "design flood" and a "design earthquake", which is a measure of the severity of hazards that each consequence classification of a dam is recommended to withstand.[36]

42. In 2007, the Dam Consequence Classification was updated from having four tiers (ranging from "low" to "very high"), to add a fifth, "extreme", classification. A design flood and design earthquake were also defined for the "extreme" category; a dam with an "extreme" consequence classification is recommended to remain stable in the event of a design flood with a maximum flood load condition of

[35] The Canadian Dam Association (**CDA**) is a Canadian organization that exists to promote excellence in dam engineering, construction and operation. It is a member society of the Engineering Institute of Canada, and serves as the Canadian national committee of the International Commission on Large Dams. The CDA is responsible for producing publications, guidelines and technical bulletins on dams in Canada, including the Dam Safety Guidelines (see Ex. B-1, Application, s. 3.2.1.1 at p. 15).

[36] Ex. B-1, Application, s. 3.2.1.1 at p. 15.

the Probable Maximum Flood (**PMF**[37]), and a design earthquake with the seismic load condition of either the 1/10,000 year event or the Maximum Credible Earthquake (**MCE**[38]).[39]

II. The BC Dam Safety Regulation (BCDSR)

43. While the CDSG sets out industry standards, it is the BCDSR that specifically regulates the Corra Linn Dam.[40]

44. The Corra Linn Dam is licensed and regulated under the *Water Sustainability Act*, SBC 2014, c 15,[41] and, as a dam owner, FBC is required to meet the requirements specified with the BCDSR. Some key provisions of the BCDSR include:

a. section 5, which requires a dam owner to:

   i. properly inspect, maintain, and repair the dam and related works to keep it in good operating condition, and

   ii. exercise reasonable care to avoid the risk of significant harm to public safety, the environment, land or other property, resulting from a defect, insufficiency or failure of the dam;[42]

b. section 14, which requires FBC to minimize the likelihood of the Corra Linn Dam developing a “Hazardous Condition”[43]; and

c. section 15, which requires FBC to minimize the likelihood of the Corra Linn Dam developing a “Potential Safety Hazard.[44]

45. There are significant penalties for non-compliance with the BCDSR.[45]

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[37] The PMF is defined by the CDSG as the most severe flood that can be reasonably expected to occur at a particular location.
[38] The MCE is defined by the CDSG as the largest possible earthquake anticipated for the site.
[39] Ex. B-1, Application, ss. 3.2.1.1.1 and 3.2.1.1.2 at pp. 16-17.
[40] Ex. B-1, Application, s. 3.2.1.1, at p. 15 and s. 3.2.1.2, at p. 17.
[41] The *Water Sustainability Act* replaced the *Water Act* on February 29, 2016.
[42] Ex. B-1, Application, s. 3.2.1.2.2 at p. 19.
[43] Ex. B-1, Application, Appendix A1, BCDSR s. 1(1) defines a “Hazardous condition” as including defects or insufficiencies in a dam that are likely to be hazardous to the dam, or may reasonably anticipated to be or become hazardous to public safety, the environment, land or other property.
[44] Ex. B-1, Application, Appendix A1, BCDSR, s. 1(1) defines a “Potential Safety Hazard” as a condition that has not yet, but has the potential to become, a hazardous condition.

46. Consistent with the CDSG, the BCDSR incorporates the Dam Consequence Classification scale. On November 20, 2011,[46] the BCDSR was updated to reflect the recent changes to the CDSG, to add the "extreme" consequence classification. Under the BCDSR, a dam falls under the "extreme" category where certain specified consequences or losses will arise following a failure of the dam, including where there is a risk to a permanent downstream population of 100 or more people.[47]

47. Where a dam has a "high", "very high" or "extreme" consequence classification, the BCDSR requires a dam owner to conduct a periodic Dam Safety Review (**DSR**). The frequency of the required DSRs is determined by the consequence classification (for example, every 10 years for a dam with a "very high classification" and every 7 years for a dam with an "extreme" classification).[48]

48. A DSR must be carried out by an engineering professional, with qualifications and experience in dam safety analysis. These professionals are guided by the Professional Practice Guideline for Legislated Dam Safety Reviews in BC, published by the Association of Professional Engineers and Geoscientists of British Columbia. These Guidelines require the engineering professionals to conduct DSRs "in compliance with the applicable legislation, these guidelines and using the guiding principles of the CDA Dam Safety Guidelines and associated technical bulletins".[49]

III. The Impact of the Changes on the Corra Linn Dam

(a) <u>The 2012 DSR</u>

49. Prior to the November 20, 2011 changes to the BCDSR, the Corra Linn Dam was rated as having a "very high" consequence classification, under the then existing four-tier classification system. With this "very high" classification, the Corra Linn Dam was required to have DSRs conducted every ten years and hence the most recent DSR at the time was completed in 2002.[50]

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45 Ex. B-1, Application, Appendix A1, BCDSR, s. 29(2)(b).

46 The BCDSR was first passed into law under the *Water Act*, as BC Regulation 44/2000, effective February 11, 2000. The November 30, 2011 amendment was passed as BC Regulation 163/2011. Note: The BCDSR was again updated on February 29, 2016, under the *Water Sustainability Act*, as BC Regulation 40/2016. The 2016 version of the BCDSR continues to align with the consequence classifications set out in the current CDSG. As designed, the Project meets the requirements of both the 2011 version of the BCDSR and the 2016 version of the BCDSR.

47 Ex. B-1, Application, s. 3.2.1.2.1, at p. 18 and Appendix A1, BCDSR, Schedule 1, ss. 1-2.

48 Ex. B-1, Application, Appendix A1, BCDSR, Schedule 2, s. 2.

49 Ex. B-1, Application, s. 3.2.1.2.2 at p. 19, emphasis added. See Footnote 17 of the Application for a link to the Professional Practice Guidelines.

50 Ex. B-1, Application, s. 3.2.2.1, at p. 20.

50. Pursuant to the BCDSR, the dam owner is required to establish the consequence classification of a dam, using a licensed engineering professional through the DSR process.[51] In 2012, FBC contracted Knight Piésold Ltd. (**KP**) to conduct a DSR (the **2012 DSR**), and to consider whether or not the Corra Linn Dam continued to satisfy the CDSG and the BCDSR.[52]

51. KP concluded in the 2012 DSR that the consequence classification of the Corra Linn Dam needed to be updated from "very high" to the newly created "extreme" classification. This was as a result of the risk of loss of life in excess of 100 persons to a permanent population residing downstream of the dam in the event the Corra Linn Dam were to fail. KP also recommended that the seismic stability and withstand capacity of the Corra Linn Dam, the spillway gates, gantry and hoists be assessed, to determine if they could withstand the updated design earthquake.[53]

52. Due to the potentially significant implications of the change in the Corra Linn Dam's consequence classification, FBC sought further clarification from KP regarding the 2012 DSR. KP reviewed its assessment, and in early 2015 confirmed its original finding that the "extreme" classification applied to the Corra Linn Dam.[54]

(b) <u>The Dam Stability Study & Gate Withstand Study</u>

53. In accordance with the recommendations made by KP in the 2012 DSR, FBC engaged KP[55] to perform a study to assess the structural stability of the Corra Linn Dam (the **Dam Stability Study)**, and engaged HMI[56] to perform a gate withstand study to assess the seismic withstand capability of the spillway gates, towers, bridges and hoists (the **Gate Withstand Study**).[57] In the Dam Stability Study, KP concluded that the Corra Linn Dam's concrete structure is expected to perform satisfactorily under the

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51 Ex. B-8, BCOAPO IR 1.3.1, at p. 3.

52 Ex. B-1, Application, s. 3.2.2.1, at pp. 20-21.

53 Ex. B-1, Application, s. 3.2.2.1, at pp. 20-21.

54 Ex. B-1, Application, s. 3.2.2.1, at p. 21.

55 In engaging KP to perform the Dam Stability Study, FBC used its recent experience with other engineering firms to determine KP's price was reasonable and prudent (including based on the estimated level of hours and comparable engineering studies). Having performed the 2012 DSR, KP was able to provide a competitive quote for the Dam Stability Study (Ex. B-10, BCOAPO IR 2.18.1 at p. 7).

56 HMI is a well-established spillway gate contractor (Ex. B-1, Application, s. 3.2.2.3, at p. 21). In engaging HMI to perform the Gate Withstand Study, FBC used its recent experience with other engineering firms to determine HMI's price was reasonable and prudent (including ensuring that the total price and hourly rates proposed by HMI was comparable to other comparable engineering firms in BC (Ex. B-10, BCOAPO IR 2.17.1 at p. 6. See also Ex. B-5, CEC IR 1.4.2 and 1.4.2.1 at p. 9-10).

57 Ex. B-1, Application, ss. 3.2.2.2 and 3.2.2.3, at pp. 21-22.

MCE and PMF, the maximum “design earthquake” and “design flood” applicable to the “extreme” consequence classification.[58]

54. With respect to the Gate Withstand Study, HMI reviewed the BCDSR and CDSG and assessed whether the Corra Linn Dam spillway gates and associated equipment would meet the design withstand capacity, including specifically the capacity of:

a. the spillway gates to withstand MCE;[59]

b. the spillway gates to operate during the PMF;

c. the superstructure to remain operable after the PMF; and

d. the hoists to remain operable after the PMF.[60]

55. HMI concluded that the spillway gates did not have sufficient capacity to withstand the MCE.[61] To rectify this situation, HMI made the following key conclusions in its report (the **HMI Preliminary Engineering Report**):[62]

a. the spillway gates require either replacement or significant refurbishment of the existing gate frame and skin plate;[63] and

b. the towers and bridges of the superstructure require reinforcement.[64]

56. As a result, the spillway gates do not satisfy the requirements of the CDSG and BCDSR, and will require replacement or refurbishment to do so.

IV. THE SPILLWAY GATES ARE APPROACHING END OF LIFE

58 Ex. B-1, Application, ss. 3.2.2.2, at p. 21.

59 The design earthquake utilized in the HMI Preliminary Engineering Report was determined by Wutec Geotechnical International, a BC based seismic engineering firm, with reference to the National Resources Canada probabilistic seismic hazard database and the BC Hydro Probabilistic Seismic Hazard Analysis Model. See Ex. B-8, BCOAPO IR 1.4.1, p. 4 and Ex. B-1, Application, Appendix C, s. 2.

60 Ex. B-1, Application, s. 3.2.2.3, at p. 22.

61 Ex. B-1, Application, s. 3.2.4, at p. 24; Ex. B-1-1, Application, Confidential Appendix E, ss. 2.6.1 and 2.6.3 at pp. 1 and 19.

62 Ex. B-1-1, Application, Confidential Appendix E.

63 Ex. B-1, Application, s. 3.2.2.3, at p. 22, citing Confidential Appendix E, s. 2.6.3.

64 Ex. B-1, Application, s. 3.2.2.3, at p. 22, citing Confidential Appendix E, ss. 5.4 and 5.5.

57. A second driver for the Project is that the Corra Linn Dam spillway gates are approaching end of life.

58. The Corra Linn Dam spillway gates have presently been in operation for 84 years. The recommended design life for new gates is 100 years; however this assumes that appropriate repairs and maintenance are able to be undertaken during the gates' service life. In the case of the Corra Linn Dam, the spillway gates were not constructed with a means of isolation from the water (for example, with a bulkhead) in order to create a dry environment for inspection and repair of the gates. This has made access to the gates more challenging, and as a result, routine maintenance and refurbishment activities, while appropriate, have been minimal.[65]

59. To determine the current condition of the spillway gates, various inspections were performed by FBC and external specialist consultants in January 2016.[66]

60. A visual inspection was performed to select three of the fourteen spillway gates for a more detailed inspection (specifically, gates ten, eleven and fourteen).[67] These gates were selected as they visually appeared to be in worse condition than the remaining gates, based on level of corrosion. However, the level of corrosion noted was not significantly different between the fourteen spillway gates,[68] and it was determined that the three selected gates are a representative sample of the condition for the remaining gates,[69] particularly as the fourteen gates are all of identical vintage and design, and have been operating under identical condition.[70]

61. A detailed inspection was conducted for the three spillway gates, along with the steel superstructure and the gate hoists, and it included a visual inspection, non-destructive testing, electrical testing and metallurgical testing.[71]

62. The detailed inspection was not able to include an inspection of the embedded parts of the spillway gates, which are the underwater portions of the spillway gates. This was because the design of the Corra Linn Dam spillway gates does not allow the gates to be isolated from the water for inspection,

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65 Ex. B-1, Application, s. 3.2.3 at p. 23.
66 Ex. B-1, Application, s. 3.2.3 at p. 23.
67 Ex. B-1, Application, s. 3.2.3 at p. 23; Ex. B-5, CEC IR 1.2.2, at pp. 3-4.
68 Ex. B-5, CEC IR 1.2.2 and 1.2.3 at pp. 3-4; Ex. B-11, CEC IR 2.21.1, at p. 1.
69 Ex. B-8, BCOAPO IR 1.5.1, at p. 5. Note: The overall cost of inspecting the three spillway gates (in addition to the steel superstructure and the gate hoists) was approximately $40,000. It is estimated that it would have cost an additional $100,000 to inspect the remaining 11 spillway gates (Ex. B-5, CEC IR 1.2.4 and 1.2.5 at pp. 4-5).
70 Ex. B-1, Application, s. 3.2.3 at p. 23.
71 Ex. B-1, Application, s. 3.2.3 at p. 23.

as described above. Instead, as a proxy, FBC used the results of an inspection of the embedded parts of another dam[72] that has spillway gates comparable to the Corra Linn Dam.[73] The embedded parts on the proxy dam had heavy corrosion in most areas that were in contact with water.[74]

63. As a result of the detailed inspection, the spillway gates of the Corra Linn Dam were assessed to be in fair to poor condition, and found to be approaching end of life.[75] While the detailed inspection was performed on only three of the spillway gates, completing inspections on the remaining eleven gates would not impact this conclusion. As was noted previously, all fourteen spillway gates were designed, built and installed at the same time, and they have been subjected to the same operating environment, meaning that they would be of similar condition and strength. In any event, even if the remaining eleven gates are in better condition than the three inspected, all gates will require refurbishment or replacement to meet the requirements of the CDSG and BCDSR.[76]

V. SUMMARY OF KEY DRIVERS

64. As was set out above, there are two primary drivers of the Project, the Corra Linn Dam spillway gates: (i) do not have the strength to withstand the "extreme" classification design earthquake event (the MCE) as is required by the CDSG and BCDSR, and (ii) are in fair to poor condition and approaching end of life.

65. In contrast, the Project is not being driven by the generating capacity of the Corra Linn Dam,[77] and FBC's obligations under the CDSG and BCDSR are not dependent on or related to the benefits of the Corra Linn generating units, the Canal Plant Agreement, or the Power Purchase Agreement.[78]

66. As a result of the key drivers, the spillway gates require either replacement or significant refurbishment to align with the withstand capacity requirements of the CDSG for a dam rated with the BCDSR "extreme" consequence classification. The required updates would mitigate the potential for a

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72 The proxy dam was undergoing maintenance, meaning that one of the gates was fully isolated, allowing for a detailed inspection of the embedded parts (see Ex. B-1, Application, s. 3.2.3, at p. 24).
73 The proxy dam is approximately twelve years newer than the Corra Linn Dam, and the proxy dam's spillway gates are similar in size and design to those at the Corra Linn Dam (see Ex. B-1, Application, s. 3.2.3, at p. 24).
74 Ex. B-1, Application, s. 3.2.3 at pp. 23-24.
75 Ex. B-1, Application, s. 3.2.3 at p. 23.
76 Ex. B-5, CEC IR 1.2.8 at p. 6.
77 Ex. B-3, BCUC IR 1.1.1, at p. 2.
78 Ex. B-9, BCUC IR 2.9.1 and 2.9.3 at pp. 1-2.

spillway gate failure, and the associated consequences to downstream populations, the environment and infrastructure.[79]

PART Five: ALTERNATIVES CONSIDERED

67. In Section 4 of the Application, FBC identified and explained four options that it considered before selecting Alternative 4: Gate Replacement, as the most suitable option for the Project.

A. SUMMARY OF THE ALTERNATIVES

68. The four alternatives identified in the Application were as follows:

a. Alternative 1: Do Nothing;

b. Alternative 2: Deferral;

c. Alternative 3: Gate Refurbishment; and

d. Alternative 4: Gate Replacement.

69. In addition to these four Alternatives, in its responses to Information Requests, FBC considered the following additional alternatives proposed, and explained why they were not feasible or not supported as alternatives for the Project:

a. replacement of the entire Corra Linn Dam spillway section with a new, "modern design" spillway, or modification of the number or type of spillway gates;[80]

b. replacing some of the spillway gates and decommissioning the others;[81] and

c. replacing some of the spillway gates and refurbishing the others.[82]

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[79] Ex. B-1, Application, s. 3.2.4 at p. 24.

[80] Ex. B-3, BCUC IR 1.4.5, at p. 28 and Ex. B-11, CEC IR 2.27.1. While FBC considered modifying the gate type or the number of gates at the Corra Linn Dam, the concrete structure of the dam itself is in good condition and does not require modification. Any design variations to the spillway section of the Corra Linn Dam would be approximately two to five times more costly than the alternatives examined in the Application.

[81] Ex. B-3, BCUC IR 1.4.4.1, at pp. 27-28. The Corra Linn Dam requires all fourteen spillway gates to safely pass the PMF required by the BCDSR. As such, decommissioning some of the gates, and replacing others, is not a feasible alternative.

[82] Ex. B-5, CEC IR 1.9.1, at pp. 19-20. While it is possible to replace some of the spillway gates and refurbish the others, the disadvantages discussed below for Alternative 3: Gate Refurbishment would apply to this option, with

B. EVALUATION OF THE ALTERNATIVES

70. To assess these four alternatives, FBC utilized four technical criteria and one financial criterion.

I. THE TECHNICAL EVALUATION CRITERIA

71. First, the following four Technical Evaluation Criteria were used to assess each of the four alternatives:

1) the ability of the spillway gates to withstand the PFM and MCE;

2) the ability of the spillway gates to remain operational post-earthquake;

3) minimize project risks; and

4) maximize the reliability of the spillway gates and associated equipment.[83]

72. The Technical Evaluation Criteria were applied to determine which of the Alternatives were feasible for the Project. The results of the application of the Technical Evaluation Criteria to the four Alternatives is summarized in Table 4-1 of the Application, as follows:[84]

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respect to the gates that were refurbished instead of replaced. Full replacement of all fourteen gates is the preferred option due to the disadvantages associated with refurbishment.

[83] Ex. B-1, Application, s. 4.1.1 at p. 25. See this section for additional details on each of the criteria.

Table 4-1: Corra Linn Dam Spillway Gate Project Alternatives Comparison

Alternative		1 Ability to Withstand the Design Flood and Design Earthquake Events	2 Ability of the Spillway Gates to Remain Operational Post-Earthquake	3 Minimize Project Risks	4 Reliability of Gates and Associated Equipment	Overall Assessment
		Project Technical Criteria (Notes 1 and 2)				
1	Do Nothing	Does not meet Criterion	Does not meet Criterion	Does not meet Criterion	Does not meet Criterion	Not Feasible
2	Deferral	Does not meet Criterion	Does not meet Criterion	Does not meet Criterion	Does not meet Criterion	Not Feasible
3	Gate Refurbishment	Meets Criterion	Meets Criterion	Does not meet Criterion	Meets Criterion	Feasible
4	Gate Replacement	Meets Criterion	Meets Criterion	Meets Criterion	Meets Criterion	Feasible

(green)	Meets the Project Technical Criteria
(red)	Does not Meet the Project Technical Criteria

(a) <u>The Feasibility of Alternative 1 & Alternative 2</u>

73. It was determined that Alternative 1 (Do Nothing) and Alternative 2 (Deferral) failed to satisfy the Technical Evaluation Criteria, and thus they were not feasible alternatives for the Project. Accordingly, these alternatives were eliminated from further consideration.

(b) <u>The Feasibility of Alternative 3</u>

74. Alternative 3 (Gate Refurbishment) would include the refurbishment of the spillway gates structure, painting of all exposed steel to provide corrosion protection, replacement of the roller bushings, rehabilitation of the embedded parts, refurbishment of the spillway gate hoists, reinforcement of the towers and bridges that support the spillway gate hoist, and upgrades to the power distribution and control systems for the spillway gates.[85]

75. With respect to the Technical Evaluation Criteria, Alternative 3 satisfies criterion 1 (it would refurbish the structure to withstand the design flood and the design earthquake) and criterion 2 (the

[85] Ex. B-1, Application, s. 4.2.3, at p. 26.

spillway gates would remain operable following the design earthquake event).[86] Alternative 3 also would allow the installation of low maintenance equipment, simplifying future maintenance.[87]

76. While Alternative 3 partially satisfies criterion 4 (it would minimize the number of possible failure modes, and minimize the risk of failure to the auxiliary equipment such as electrical power supply, hoists and towers), the potential for latent defects would remain following the refurbishment,[88] arising from undetected defects related to pre-existing corrosion on the existing gates. The latent defects result in increased structural stress levels that impact the strength of the gates, making it more susceptible to fatigue, and ultimately, failure.[89]

77. Additionally, Alternative 3 does not satisfy criterion 3, and therefore does not minimize project risks. Refurbishment is the alternative with the highest project risks, which may result in cost variances. The anticipated project risks include the following:

a. the required construction method is complex and refurbishment activities must take place in the field, which may potentially negatively impact the Project schedule;

b. as the precise condition of each gate cannot be confirmed until it is removed from service and inspected, there is the potential for Project scope variation with refurbishment;

c. as refurbishment would require the removal of lead paint, repainting and millwork in close proximity to or immediately above the water, this alternative would require environmental mitigation measures; and

d. the work above or in close proximity to the water, as well as in constrained areas that are challenging to access, would also increase the risk of the safety to workers, and would require the use of complex work procedures and extensive temporary scaffolding and complex work procedures.[90]

[86] Ex. B-1, Application, s. 4.3.1.3, at pp. 30-31.
[87] Ex. B-1, Application, s. 4.3.1.3, at pp. 30-31.
[88] Ex. B-1, Application, s. 4.3.1.3, at pp. 30-31.
[89] Ex. B-1, Application, s. 4.3.1.3, at p. 31; Ex. B-5, CEC IR 1.10.1, at pp. 22-23.
[90] Ex. B-1, Application, s. 4.3.1.3, at p. 30; Ex. B-8, BCOAPO IR 1.6.1, at p. 7.

78. Finally, Alternative 3 is only expected to extend the life of the Corra Linn Dam spillway gates by approximately 11 to 25 years.[91] The existing Corra Linn Dam spillway gates are approximately 84 years old, their maintenance has been minimal due to access challenges, and they are currently assessed to be in "fair to poor condition" and approaching end of life.[92] Even with full implementation of Alternative 3, the existing gates will have the potential for latent defects, resulting in increased structural stress levels that impact the strength of the gates.[93] Accordingly, Alternative 3 would require FBC to again consider replacement of the gates within the next 15 to 25 years.[94]

(c) <u>The Feasibility of Alternative 4</u>

79. The final alternative is Alternative 4 (Gate Replacement), which would include the construction of 14 new spillway gates (manufactured to present day design requirements), repair or upgrade of the embedded parts (as required), reinforcement of the towers and bridges that support the spillway gate hoists, repair and replacement of the spillway gate hoists (as required), and upgrades to the power distribution and control system for the spillway gates.[95] The expected working life of the new gates is 100 years.[96]

80. Alternative 4 satisfies all four Project Technical Criteria, and no disadvantages were identified with this option. The advantages of Alternative 4 may be summarized as follows:

a. with replacement, the gates would withstand the PMF and MCE, and would remain operational post-earthquake;

b. the project risks are also minimized, including reduced environmental risks, as the new gates are painted offsite as opposed to in proximity to the water;

c. there would be a shorter construction period, allowing all fourteen gates to be back in service more quickly;

d. as new gates will be utilized, they will be designed to incorporate the engineering developments that have occurred over the last 85 years;

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91 Ex. B-1, Application, s. 4.3.1.3, at p. 30; Ex. B-3, BCUC IR 1.4.2, at pp. 24-25.
92 Ex. B-1, Application, s. 3.2.3 at p. 23.
93 Ex. B-1, Application, s. 4.2.1.3, at p. 31; Ex. B-5, CEC IR 1.10.1, at p. 22.
94 Ex. B-1, Application, s. 4.3.1.3, at p. 30; Ex. B-3, BCUC IR 1.4.2, at pp.24-25.
95 Ex. B-1, Application, s. 4.2.4, at p. 27.
96 Ex. B-3, BCUC IR 1.4.1, at p. 24.

e. the new gates will have new rollers with anti-friction bearings and a centralized lubrication system, which will facilitate the ease of operation and reliability of the gates and will allow for simplified maintenance (as the lubrication system will allow for the greasing of the bearings without the need to open or climb down the spillway gates for maintenance access);

f. the new gates would have thicker skin plate than the existing spillway gates, reducing the risk of gate failure;

g. replacement reduces safety risks to the public, plant property and FBC personnel;

h. this alternative minimizes the risk of generation interruption as a result of unplanned spillway gate failures; and

i. as new gates would be installed, this alternative results in the maximum lifetime extension for the spillway gates.[97]

(d) Summary of Technical Evaluation Criteria

81. As was noted previously, Alternative 1 (Do Nothing) and Alternative 2 (Deferral) do not satisfy the Technical Evaluation Criteria; as they do not mitigate the reliability, safety and regulatory risks that are driving the need for the Project, they are not feasible alternatives. In contrast, each of Alternative 3 (Gate Refurbishment) and Alternative 4 (Gate Replacement) are feasible alternatives, though only Alternative 4 achieves all four of the Technical Evaluation Criteria.

82. From a technical perspective, the Company confirms that further inspections of the spillway gates and the associated equipment would not assist in determining whether Alternative 3 (Gate Refurbishment) or Alternative 4 (Gate Replacement) is the preferred alternative for the Project.[98] Accordingly, to further compare these alternatives and select the best option for the Project, the Financial Evaluation Criterion was next applied.

II. THE FINANCIAL EVALUATION CRITERION

[97] Ex. B-1, Application, s. 4.3.1.4, at pp. 32-33; Ex. B-5, CEC IR 1.10.2, at p. 23.
[98] Ex. B-5, CEC IR 1.9.1, at p. 20.

83. One Financial Evaluation Criterion was used to evaluate Alternative 3 (Gate Rehabilitation) and Alternative 4 (Gate Replacement), specifically, to minimize the customer financial impacts of the Project.[99]

(a) Initial Capital Costs & Revenue Requirements

84. To assess the financial impact of the Alternatives, first the Company performed a comparison of the initial capital costs of each Alternative 3 (Gate Refurbishment) and Alternative 4 (Gate Replacement). These assessments were determined based on AACE International Recommended Practice No. 69R-12 Class 3 Estimate (**AACE Class 3**), and the results are summarized as follows:[100]

Table 4-2: Comparison of Initial Capital Costs between Alternative 3 and 4 ($ millions)

	Alternative 3: Gate Refurbishment		Alternative 4: Gate Replacement	
	2015 $	As-Spent $	2015 $	As-Spent $
Engineering	2.492	2.665	2.349	2.506
Supply, Installation & Testing	20.278	21.687	18.098	19.302
Site-Support Work	7.732	8.269	9.443	10.071
Indirect Costs	0.720	0.770	0.624	0.666
Project Management	6.375	6.818	4.322	4.610
Subtotal Construction	*37.596*	*40.209*	*34.837*	*37.155*
Removal Cost[39]	-	-	5.331	5.804
Construction Contingency	2.255	2.412	2.008	2.148
Subtotal Construction & Removal	*39.851*	*42.620*	*42.177*	*45.108*
FBC – Project Management	2.920	3.155	2.920	3.155
Generation Admin Overhead	0.543	0.589	0.543	0.589
Project Contingency[40]	6.497	6.955	6.846	7.328
Pre-Approval Project Costs[41]	1.062	1.081	1.062	1.081
Subtotal (incl. Construction & Removal)	*50.873*	*54.400*	*53.548*	*57.260*
AFUDC	n/a	5.394	n/a	5.434
TOTAL Project Capital Costs	**50.873**	**59.794**	**53.548**	**62.694**

85. In addition, the Company performed a comparison of the revenue requirement for each of Alternative 3 (Gate Refurbishment) and Alternative 4 (Gate Replacement):101

99 Ex. B-1, Application, s. 4.1.1, at p. 25.
100 Ex. B-1, Application, Table 4-2, at p. 35.
101 Ex. B-1, Application, Table 4-3, at p. 36.

Table 4-3: Financial Analysis of Alternatives ($ millions unless otherwise stated)

	Alternative 3: Gate Refurbishment	Alternative 4: Gate Replacement
As-spent Capital Costs (incl. AFUDC & Removal)	59.794	62.694
2022 Incremental Rate Base[42]	58.166	61.153
PV of Incremental Revenue Requirement - 70 years[43]	105.808	85.018
% Increase on Rate - Year 2022	1.41%	1.49%
Levelized % Increase on Rate - 70 years	1.81%	1.46%
Discounted Cash Flow NPV	1.598	1.868

86. Comparing these alternatives, Alternative 4 (Gate Replacement) is approximately $2.9 million more expensive than the gate refurbishment option, in as-spent initial capital costs.102

(b) <u>Long-Term Financial Impacts</u>

87. While Alternative 4 (Gate Refurbishment) is more expensive in terms of initial capital costs, the above analysis does not take into account the long-term financial impacts of each of the alternatives. Specifically, under Alternative 3 (Gate Refurbishment), even after refurbishment, full replacement of the spillway gates is expected to be required within approximately 15 to 25 years. In comparison, in Alternative 4 (Gate Replacement), the new spillway gates will have an estimated service life of 100 years,103 and no further replacement of the gates would be required during the 70 year analysis period of the Project.104

88. Assuming that the refurbished gates in Alternative 3 require replacement in approximately 15 years (once the gates are 100 years of age in 2032), the cost of this installation is estimated to be approximately $33.723 million (as spent), plus an additional $7.729 million in removal costs for the existing gates.105 When this replacement value is included in Alternative 3, the net present value of the incremental revenue requirement over a 70 year period is increased to $105.808 million, which is approximately $21 million more than Alternative 4 (which is $85.018 million).106

89. Even if the refurbishment in Alternative 3 is able to extend the service life of the existing spillway gates by a full 25 years (such that replacement would be required in 2045), the net present

[102] Ex. B-1, Application, s. 4.3.2, at p. 36.
[103] Ex. B-3, BCUC IR 1.4.1, at p. 24.
[104] Ex. B-1, Application, s. 4.3.2, at p. 37.
[105] Ex. B-1, Application, s. 4.3.2, at p. 36.
[106] Ex. B-1, Application, s. 4.3.2, at p. 37.

value of the incremental revenue requirement of Alternative 3 over a 70 year period would be increased to $94.897 million, which is still approximately $10 million more than Alternative 4.107

III. THE PREFERRED ALTERNATIVE 4: GATE REPLACEMENT

90. Based on the evaluation using the Technical Evaluation Criteria and the Financial Project Criterion, Alternative 4 (Replacement) is the preferred solution for the Project. In addition to addressing all of the technical goals of the Project, Alternative 4 also minimizes the financial impacts of the Project over the long term.

PART Six: PROJECT DESCRIPTION

91. The recommended alternative, Alternative 4: Gate Replacement, is comprised of the following Project components:

a. replacement of the fourteen existing spillway gates;

b. reinforcement of the existing spillway towers and bridges;

c. reinforcement of the existing hoists; and

d. replacement of the existing embedded parts.[108]

92. The details of each of these components of the Project are set out in section 5.1 of the Application.

93. The Company will assign an experienced team to oversee the Project and necessary controls will be put in place. This will include a Project Director, a Project Manager, and an FBC Construction Manager. A proposed Organization Chart for the Project may be found in the Company’s response to the Commission’s Information Request 1.2.2.[109]

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[107] Ex. B-1, Application, s. 4.3.2, at p. 37; Ex. B-3, BCUC IR 1.4.2.2, at p. 25.
[108] Ex. B-1, Application, s. 5.1, at p. 39.
[109] Ex. B-3, BCUC IR 1.2.2, at p. 8.

A. CONTRACTING MODEL

94. The first stages in FBC's execution and schedule of the Project is for the Company to select its preferred contracting model, and then to complete is contractor selection and Award.[110]

95. As is set out in more detail below, FBC has not yet selected its preferred contracting model for the Project. However, it is evaluating the merits of utilizing an Early Contractor Involvement (**ECI**) model. The ECI model being contemplated has two distinct phases: an Open Book Phase (**OBP**) and a Design Build Phase (**DBP**).[111] Through Information Requests, several questions were raised by the Commission and Interveners regarding the contract model selection process and the ECI model. For clarity, in this section of the Final Submission, FBC provides a summary of the steps it will follow during the Contractor Selection and Award phase of the Project to determine its preferred contracting method, select a contractor, negotiate the key contractual terms, and ultimately execute the Project.

I. Selection of Preferred Contracting Model

96. The Company anticipates selecting its preferred contracting method by the end of November 2016, in accordance with the proposed Project schedule.[112] To assist in this, the Company has engaged Bramcon Project Consultants Ltd. (**Bramcon**),[113] an experienced engineering and project management firm. Bramcon has extensive knowledge in the suitability and application of various project delivery methods in British Columbia. This includes specific experience with developing and executing projects that utilize the ECI contracting model.[114]

97. To determine the preferred contracting model, Bramcon will assist FBC in evaluating the ECI model for the Project by assessing, among other things, the potential risks and their likely allocation, the complexities of the Project, constructability, and likelihood for scope changes associated with the Project.[115]

[110] Ex. B-1, Application, s. 5.3.1, at p. 45.
[111] Ex. B-3, BCUC IR 1.2.3, at pp. 9-10.
[112] Ex. B-9, BCUC IR 2.10.2, at p. 5.
[113] Bramcon's principal is Mr. Bryan McConachy, who is both a Professional Engineer and a Project Management Professional (who was elected a Fellow of the Project Management Institute). Bramcon was retained by BC Hydro in 2009 with respect to their spillway gate program, and it worked with BC Hydro to both develop the ECI process and through the execution phase (Ex. B-9, BCUC IR 2.10.2, at p. 5).
[114] Ex. B-9, BCUC IR 2.10.2, at p. 5.
[115] Ex. B-9, BCUC IR 2.10.2, at p. 5.

(a) The ECI Model

98. As was mentioned previously, FBC is considering utilizing the ECI project delivery model. Under the ECI model, the owner engages a construction contractor at an early stage to develop the scope of work for the project, *prior* to finalizing the contract price. Once a contractor is selected (the "**ECI Contractor**"), the scope of work, deliverables, risk and costs for the project are developed collaboratively and a construction estimate is developed in an open-book format until a price can be agreed upon between the contractor and owner.[116] The model seeks to balance risk, price and control of a project.[117]

99. Due to the involvement of a knowledgeable contractor at the early stages of a project, the ECI model is well suited for one-of-a kind projects that pose unique challenges.[118] This would be a major advantage of the ECI model for the Project, as it would allow the Company to leverage the experience of a knowledgeable contractor during the early stages of the Project, to reduce variations in the schedule and costs of the Project, and to address the unique challenges posed by the Project (specifically, the specialized nature of the type of lifting required for the spillway gates, and the challenges to access to the Project site).[119]

100. In contrast, a major disadvantage associated with the ECI model is increased owner participation during the early stages. In the case of the Project, FBC plans to mitigate this disadvantage by engaging the services of an Owner's Engineer. The Owner's Engineer will assist in the review process during the OBP (helping to manage the increase demand on FBC's resources during this phase), provide an assessment and recommendations on the reasonableness of project costs that are not competitively tendered, and assist with reviewing the technical specifications and design of the Project.[120]

101. Should the evaluation by FBC and Bramcon not support the implementation of an ECI contracting model for the Project, then the Company would consider alternative project delivery methods, such as a Design Build Tender. This would involve engaging an Owner's Engineer to support the completion of the necessary contracting documentation.[121]

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116 Ex. B-11, CEC IR 2.24.1, at p. 6.
117 Ex. B-3, BCUC IR 1.2.3, at p. 9.
118 Ex. B-3, BCUC IR 1.2.3, at p. 9.
119 Ex. B-3, BCUC IR. 1.2.3, at p. 9; Ex. B-5, IR CEC 1.13.3, at p. 30.
120 Ex. B-11, CEC IR 2.25.1, at pp. 8-9.
121 Ex. B-9, BCUC IR 2.10.2, at p. 6.

II. SELECTION OF AN ECI CONTRACTOR

102. Assuming that FBC selects proceeding with the ECI model, it will next select its ECI Contractor. Given the importance of the work to be completed during the OBP, the selection of the ECI Contractor is critical to the success of the ECI model.[122]

103. FBC is contemplating selecting HMI as the ECI Contractor for the Project.[123] FBC selected HMI to assist with developing the construction cost estimate for the Project for the purposes of this Application for a number of reasons, including:

a. HMI is recognized as an industry leader in spillway gate rehabilitation projects in Canada;

b. HMI has recently completed projects of similar scope as the Project within BC, and is currently engaged by BC Hydro through to 2026 for their spillway gate rehabilitation program;

c. HMI has extensive knowledge of the ECI model through its involvement with BC Hydro using this model since 2010; and

d. HMI has the required in-house capabilities for engineering (design and inspection), fabrication, installation and commissioning.[124]

104. These factors also make HMI well suited to act as the ECI Contractor for the Project.[125] Further, selecting HMI as the ECI Contractor would allow the Company to fully leverage its well-established working relationship with HMI (that it has developed over the past 18 months), and to utilize the engineering that has already been completed by HMI.[126]

105. Despite the advantages of using HMI as the ECI Contractor, FBC confirms that it has not presently engaged HMI for this role,[127] and it has no contractual obligation to engage HMI as the ECI

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[122] Ex. B-9, BCUC IR 2.10.2, at p. 6.
[123] Ex. B-9, BCUC IR 2.10.2, at p. 6.
[124] Ex. B-9, BCUC IR 2.10.2, at p. 6.
[125] Ex. B-9, BCUC IR 2.10.2, at p. 6; FBC also sought the opinion of consulting firm Hatch Ltd. (**Hatch**), whose personnel have worked closely with HMI over the past ten years on the BC Hydro spillway gate project, and Hatch confirmed the technical and design capabilities of HMI (see Ex. B-5, CEC IR 1.18.1, at p. 42).
[126] Ex. B-9, BCUC IR 2.10.2, at p. 6
[127] Ex. B-3, BCUC IR 1.2.3, at p. 9.

Contractor.[128] FBC will engage Bramcon to advise on the suitability of HMI as the ECI Contractor, having considered:

a. HMI's corporate capabilities in the design and construction of spillway gates and components;

b. HMI's success on recent rehabilitation projects in BC;

c. HMI's experience with the ECI model;

d. HMI's financial capacity to provide a bond for the Total Construction Cost; and

e. HMI's ability to provide all the required types and levels of insurance required by FBC.[129]

106. Bramcon's recommendation and FBC's decision regarding HMI are expected by end of November 2016.[130]

107. Should the evaluation of FBC and Bramcon not support the engagement of HMI as the ECI Contractor, the Company will instead select an ECI Contractor through a Request for Proposal (**RFP**) process. This process would require the contractor to state, among other things, their proposed mark-ups, terms and conditions exceptions and engineering and design rates, to allow FBC to assess their viability as an ECI Contractor.[131]

III. Negotiation of Key Contractual Terms

108. Once the ECI Contractor has been selected (either HMI is recommended by Bramcon and selected by FBC, or, if HMI is not selected, the ECI Contractor that is selected through an RFP process), FBC will negotiate a number of key commercial terms with the ECI Contractor that will form part of the contract for the DBP phase (the "**DBP Contract**").[132]

109. The process of negotiating these key commercial terms of the DBP Contract prior to entering into the OBP ensures that the parties are able to agree upon fair and competitive terms. The key terms that will be negotiated include:

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128 Ex. B-11, CEC IR 2.26.1, at p. 10.
129 Ex. B-9, BCUC IR 2.10.2, at p. 6.
130 Ex. B-9, BCUC IR 2.10.2, at p. 6.
131 Ex. B-9, BCUC IR 2.10.2, at p. 6.
132 Ex. B-9, BCUC IR 2.10.2, at p. 7.

a. the percentage of profits and overheads to be applied to the direct costs established at the end of the OBP (the reasonableness of which will be assessed against benchmarks, including those established by Bramcon);[133]

b. any exceptions that the ECI Contractor may take to the terms and conditions of FBC's standard services agreement and Design Build contracts;

c. the methodology that would be undertaken to competitively tender the construction work; and

d. the limitations and expectations for work to be self-performed by the ECI Contractor.[134]

110. In the unlikely event that FBC and the ECI Contractor could not agree on these conditions, FBC will issue an RFP for another ECI Contractor (or, if one had already been issued as part of one of the prior stages, FBC would select the next best proponent from the previous RFP process). The process would permit an ECI contractor to be in place by the end of March 2017.[135]

IV. The OBP

111. Once the ECI Contractor is selected and key commercial terms agreed upon, the OBP would commence. This would occur following Commission approval of the Project.

112. The OBP of the Project would be designed to ensure cost competitiveness and that fair market value is achieved. This will be done through the following:

a. approximately 70% of supplier and sub-contract packages will be tendered and therefore competitively priced;[136]

b. an independent Owner's Engineer will be engaged to analyze, review and advise on the appropriateness and competitiveness of cost of the work not tendered or work to be self-performed by the ECI Contractor;[137] and

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[133] This percentage will be negotiated between FBC and the ECI Contractor, and its reasonableness will be demonstrated by comparing it to benchmarks, including those established by Bramcon as a result of its experience on previous ECI projects (see Ex. B-9, BCUC IR 2.10.2, at p. 7).
[134] Ex. B-9, BCUC IR 2.10.2, at p. 7.
[135] Ex. B-9, BCUC IR 2.10.2, at p. 7.
[136] Ex. B-9, BCUC IR 2.10.2, at p. 7.

c. if consensus cannot be achieved between FBC and the ECI Contractor on the cost of the work not tendered or to be self-performed, FBC will either request that the ECI Contractor tender that part of the self-performed work, or request that the ECI Contractor demonstrate that the cost is competitive by obtaining comparable quotes.[138]

113. A preliminary Risk Register was prepared jointly by FBC and HMI as part of the Application, as an estimate of the known Project risks. However, during the OBP of the Project, known project risks would be further identified by FBC and the ECI Contractor, with the assistance of the Owner's Engineer.[139] Each known risk would be allocated to the party that is best able to manage and control the particular risk. This transparent process results in known risks being built into both the owner and contractor's component of the Total Project Contingency. To the extent a known risk assigned to FBC does not manifest, the associated cost is not incurred.[140]

114. In the event that FBC and the ECI Contractor are unable to reach an agreement at the end of the OBP, the following will occur:

a. the ECI services agreement between the ECI Contractor and FBC will include terms that the ECI Contractor must:

   i. complete the design within an agreed to timeframe following written notice by FBC that the DBP Contract cannot be achieved; and

   ii. provide certain deliverables (such as final design drawings, design memorandum and specifications),

b. FBC will then use the completed design document to prepare a Request For Quotation (**RFQ**) and request tender for the construction of the Project.[141]

115. In these circumstances, the ECI contractor would not be eligible to submit a tender response. In the event an RFQ was required at this stage, there would be a corresponding schedule impact of several months, as well as carrying and other cost impacts arising from this delay.[142]

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137 Ex. B-9, BCUC IR 2.10.2, at p. 7.
138 Ex. B-10, BCOAPO IR 2.13.1, at p. 13.
139 Ex. B-3, BCUC IR 1.2.3, at p. 12.
140 Ex. B-11, CEC IR 2.28.1, at p. 13.
141 Ex. B-9, BCUC IR 2.10.2, at p. 8.

V. *The DBP*

116. By the end of the OBP, FBC and the ECI Contractor will have agreed to the Project scope, deliverables, costs, risks, and all terms which will form the fixed lump sum bonded price for the DBP Contract.[143]

117. Finally, the DBP Contractor will implement the DBP Contract and complete the Project.

B. CONSTRUCTION AND OPERATING SCHEDULE

118. After contractor selection and contract award, the following steps remain in the implementation of the Project:

a. detailed design of Project (estimated to commence July 2017 and conclude June 2018);

b. procurement, manufacturing and delivery (estimated to occur from mid-August 2017 to September 2019);

c. mobilization to site (estimated to last approximately three months, starting in June 2018); and

d. site installation (estimated to start in August 2018 and conclude in December 2020).[144]

119. Additional details on these stages of execution of the Project are set out in Sections 5.3.2 through 5.3.5 of the Application.

120. A detailed schedule for the Project may be found at Appendix G to the Application.[145] FBC confirms that there would not be any cost savings associated with extending this schedule beyond the proposed December 2020 in service date.[146]

C. REPORTING REQUIREMENTS

121. As was proposed by the Commission, the Company has no concerns with filing a letter with the Commission, from the Owner's Engineer, stating that the Owner's Engineer has reviewed a) the

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142 Ex. B-9, BCUC IR 2.10.2, at p. 8.
143 Ex. B-9, BCUC IR 2.10.2, at p. 8.
144 Ex. B-1, Application, ss. 5.3.2 to 5.3.5, at pp. 45-48.
145 Ex. B-1, Appendix G.
146 Ex. B-3, BCUC IR 1.3.3, at p. 22; Ex. B-10, BCOAPO IR 2.15.1, at p. 4.

contractor's Project costs and finds them to be fair market value, b) the scope/work package documents associated with the contractor's Project costs and finds them to be consistent with industry best practice in general and consistent with the objective of minimizing the overall project cost; and c) the design specifications and scope/work package documents and finds them to be consistent with industry best practice in general and consistent with the objective of minimizing the overall cost from change orders.[147]

122. The Company is also supportive of providing the Commission Semi-Annual Progress Reports for the Project, along with a requirement to provide the Commission a report of any material changes to the schedule (i.e. greater than 6 months) or costs (i.e. greater than 10% of the Total Project Capital Cost), within 30 days of identification of the material changes. This strikes an appropriate balance between Commission oversight of the execution of the Project, and FBC's responsibility for the ongoing management of the Project.[148]

123. Additionally, FBC proposes filing a Final Report with the Commission that provides a complete breakdown of the final costs of the Project, compares these costs to the cost estimates in the Application, and provides an explanation and justification of any material variances, to be filed within six months of the actual completion of the Project.[149]

PART Seven: PROJECT COST ESTIMATE

124. The total capital cost of the Project is forecasted to be $62.694 million (as spent). This includes AFUDC of $5.434 million and removal costs of $6.094 million:[150]

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147 Ex. B-9, BCUC IR 2.10.8, at p. 11.
148 Ex. B-3, BCUC IR 1.8.1, at p. 38.
149 Ex. B-1, Appendix P2.
150 Ex. B-1, Application, Table 6.1, at p. 59 and Table 6.6, at p. 63

Table 6-1: Summary of Estimated Project Capital Costs ($ millions)

	2015 $	As-Spent $
Contractor's Costs		
Engineering	2.349	2.506
Supply, Installation & Testing	18.098	19.302
Site-Support Work	9.443	10.071
Indirect Costs	0.624	0.666
Project Management	4.322	4.610
Subtotal	*34.837*	*37.155*
Removal Cost[50]	5.331	5.804
Construction Contingency	2.008	2.148
Total Contractor Costs	*42.177*	*45.108*
FBC Owner's Costs		
FBC – Project Management	2.920	3.155
Generation Admin Overhead	0.543	0.589
Project Contingency[51]	6.846	7.328
Pre-Approval Project Costs	1.062	1.081
Subtotal (Contractor & Owner's Costs)	*53.548*	*57.260*
AFUDC	n/a	5.434
TOTAL Project Capital Costs	*53.548*	*62.694*

A. PREPARATION OF THE PROJECT COST ESTIMATE

125. The cost estimate was developed to meet the requirements of the AACE Class 3 specifications, with a Low -10% to -20% and a High: +10% to +30%. This approach is consistent with the Commission's CPCN Guidelines.[151]

126. FBC engaged HMI to assist with the preparation of the estimate, as the Project requires a specialized skill set, a consideration of the construction complexities and the duration of the work, and the preparation of a cost estimate that is required for an AACE Class 3 level.[152] HMI has a unique understanding of BC construction labour, materials, and equipment rates, given its experience as a

[151] Ex. B-1, Application, s. 6.1, at p. 56; Ex. B-3, BCUC IR 1.3.1, at p. 20.
[152] Ex. B-1, Application, s. 6.1, at p. 56.

contractor for BC Hydro for similar projects, and other projects.[153] This made them well suited to assist with preparing the estimate.

B. DETERMINATION OF PROJECT CONTINGENCY

127. The total estimated capital costs for the Project includes a line item for "Project Contingency" of $7.328 million (as spent).[154]

128. To estimate the Project Contingency amount, FBC sought the expert assistance of HMI,[155] which has performed various contingency evaluations and risks on similar projects that it has recently undertaken.[156] FBC also used its own judgment to determine the appropriate contingency amount.[157] The Company determined that it was not appropriate to utilize the Monte Carlo method or parametric modeling to estimate the Project Contingency, due to the limited amount of reliable, historical information available, which is required to utilize these methods.[158]

129. The Project Contingency is comprised of two parts: the "owner's known risks" and "unknown risks",[159] a breakdown of which may be found at FBC's Confidential Response to Commission Information Request 1.3.2.1.[160] While the Project Contingency amount includes the owner's known risks, it does not include the known construction risks for the Project that are held by the contractor under the ECI Model.[161] These amounts are included in the "Construction Contingency" amount,[162] which is estimated to be $2.148 million (as spent).[163]

I. OWNER'S KNOWN RISKS

130. The owner's known risks include those "known risks" for the Project that FBC and HMI were able to identify based their respective past project experiences. These known risks include items such as delay in obtaining necessary permits or approvals, unforeseen conditions with the embedded structure,

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153 Ex. B-1, Application, s. 6.1, at p. 56.
154 Ex. B-1, Application, Table 6-1, at p. 59.
155 Ex. B-1, s. 6.3.1.2, at p. 60.
156 A table summarizing HMI's past estimates of construction contingencies, and the portion of the contingency utilized is contained at Ex. B-11, CEC, IR 2.23.1, at p. 4.
157 Ex. B10, BCOAPO IR 2.14.1, at p. 3.
158 Ex. B-1, Application, s. 6.3.1.2, at p. 60; Ex. B-9, BCUC IR 2.12.2, at p. 14.
159 Ex. B-1, Application, Footnote 51, at p. 59.
160 Ex. B-4, Confidential BCUC IR 1.3.2 at p. 1..
161 The Risk Registrar identifies which of the known risks are most likely to be held by the contractor. These risks are included in the Construction Contingency. The remaining risks are most likely to be held by the Owner (and are included in the Owner's known risks).
162 Ex. B-5, CEC IR 1.19.1, at pp. 44-45.
163 Ex. B-1, Application, Table 6-1, at p. 59.

parts or concrete, unforeseen project management resourcing requirements, construction delays and re-work.[164]

131. To quantify the owner's known risks, the Risk Register[165] was developed collaboratively by FBC and HMI. The Risk Register identifies the known risks, and assigns a probability rating (the likelihood that the risk will occur), and the financial impact that will arise if the risk actually materializes. The probability of each risk occurring is multiplied by the risk's estimated financial impact, and these amounts are summed together to determine the owner's known risks portion of the Project Contingency.[166]

II. Unknown Risks

132. In addition to the risks that HMI and FBC were able to identify and include in the Risk Register, the Company has included a contingency for "unknown risks" to account for future events that cannot be anticipated, and therefore cannot be included in the Risk Register.[167]

133. Given the unknown nature of these risks, the amount for unknown risks was quantified by determining an appropriate overall Project Contingency for the Project, and subtracting the quantified owner's known risks from the Risk Register. The balance is the amount for unknown risks.[168]

134. AACE International does not have a standard that provides the correct or appropriate level of contingency to include for a project. In the circumstances of the Project, FBC determined that it would reasonable and appropriate to utilize a total Project Contingency of 15%. This contingency was determined based on the complexity and scale of the Project, the effort that has gone into engineering, designing and developing the Project by FBC and HMI to date, and industry references.[169]

C. REVENUE REQUIREMENT IMPACT

135. The financial and rate impacts associated with the Project is summarized in the following table:[170]

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164 Ex. B-1, Application, s. 6.3.1.2, at p. 60.
165 Ex. B-1-1, Confidential Appendix H.
166 Ex. B-1, Application, s. 6.3.1.2, at p. 61.
167 Ex. B-1, Application, s. 6.3.1.2, at p. 61.
168 Ex. B-3, BCUC IR 1.3.2.1, at p. 21.
169 Ex. B-3, BCUC IR 1.3.2.1, at p. 21.
170 Ex. B-1, Application, Table 6-6, at p. 63.

Table 6-6: Financial Analysis and Rate Impact of Project

AACE Class 3	Corra Linn Spillgates
Total Charged to Electric Plant in Service ($ millions)	56.599
Cost of Removal ($ millions)	6.094
Total Capital Costs incl. Cost of Removal ($ millions)	62.694
% Increase on Rate - Year 2022	1.49%
Levelized % Increase on Rate - 70 years	1.46%
PV of Incremental Revenue Requirement - 70 years ($ millions)	85.018
Discounted Cash Flow NPV ($ millions)	1.868
2022 Incremental Rate Base ($ millions)	61.153

136. When all assets have entered into rate base in 2022,[171] the impact to customer rates is an approximately increase of 1.49% over the 2016 approved Revenue Requirements. Over a 70 year analysis period, the levelized rate impact to customers is an approximately increase of 1.46%. For a typical FBC residential customer consuming an average of 991 kWh per month, this would equate to an approximate bill increase of $1.83 per month in 2022.[172]

PART Eight: PUBLIC AND FIRST NATIONS CONSULTATION

137. FBC's responsibility to engage stakeholders in a meaningful and comprehensive consultation process is a key consideration in its successful development of projects. FBC is committed to meaningful stakeholder engagement on all major projects it undertakes.

138. With respect to the Project, all permanent works will be entirely contained within an existing FBC generation facility. During the implementation of the Project, each spillway gate will be isolated from the Kootenay River, ensuring that the flow of the river is not impacted, and that there are no expected impacts on either the environment, or the fish population.[173]

139. With respect to non-permanent works, a new gravel road may be required to access the downstream side of the left bank's concrete dam. A potential route has been identified for this road,

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[171] The phased inclusion of the Project into rate base will occur between the years 2020 and 2022 (Ex. B-3. BCUC IR 1.6.1, at p. 33).

[172] Ex. B-1, Application, s. 6.5, at p. 63.

[173] Ex. B-1, Application, ss. 7 and 7.1, at pp. 65-66.

along with a gravel area that could serve as a staging area during construction.[174] FBC has not yet finalized the location of the access road or staging area.

140. Public consultation has been fairly limited for the Project, given that the permanent works will be contained entirely within an existing FBC facility. The Company has discussed the potential for this Project with the International Joint Commission (**IJC**),[175] on several occasions since 2013. The IJC has not raised any concerns. FBC also identified the Regional District of Central Kootenay (**RDCK**) as a local stakeholder with a possible interest in the Project. FBC representatives discussed the Project with RDCK in person, by mail and on the telephone on September 9, 2015, November 3, 2015 and November 30, 2015. One potential concern raised by RDCK has been addressed by FBC (the Project will not result in the disturbance of any contaminated soil).[176]

141. With respect to First Nations, the Company has identified twelve First Nations that have an interest in the area of the Corra Linn Dam using the provincial Consultative Area Database Public Map Service. As was noted above, all permanent works of the Project will occur within the Corra Linn facility, and will not affect Aboriginal Rights or Title.

142. With respect to the temporary works, the construction of an access road and staging route has the potential to cause ground disturbance. However, as was noted above, the exact site of the access route and staging area has not yet been finalized, meaning that the area being disturbed has not been determined. Once the Company has finalized this location, it will notify all twelve identified First Nations with the details of any potential disturbance, and it will conduct an archeological study for the impacted areas.[177]

PART Nine: CONCLUSION

143. In all the circumstances, FBC requests that the approvals sought in its Application be granted, namely that the CPCN be granted to FBC to construct and operate the Corra Linn Dam Spillway Gate Replacement Project, as was applied for in the Application.

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[174] Ex. B-1, Application, s. 5.4, at p. 48.

[175] The International Joint Commission is a commission that regulates shared water use between Canada and the United States. It approved the Corra Linn Dam in 1938, and established the International Kootenay Lake Board of Control to supervise the construction and subsequent operation of the Corra Linn Dam (see Ex. B-1, Application, footnote 58 at p. 65).

[176] Ex. B-1, Application, s. 7, at p. 65.

[177] Ex. B-3, BCUC IR 1.5.2 and 1.5.5, at pp. 31-32.

144. ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated:	November 14, 2016	***[original signed]***
		Erica C. Miller
		Counsel for FortisBC Inc.

BOOK OF AUTHORITIES

BOOK OF AUTHORITIES

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In the Matter of an Application by British Columbia Transmission Corporation, CPCN for *the* Vancouver Island Transmission Reinforcement Project, Decision, July 7, 2006

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 never indicated at any point 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 $0.0004 \times 2190 = 0.876$ 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 firm 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.

<u>Table 9-1: Initial VITR Incentive / Penalty Framework Proposed by BCTC</u>

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

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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
L.A. O'Hara, Commissioner

July 7, 2006

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

. . ./2

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 C. BYSTROM	British Columbia Transmission Corporation
P.J. LANDRY J. HERBERT	Sea Breeze Pacific Regional Transmission System Inc. Sea Breeze Victoria Converter Corporation
C.W. SANDERSON C. GODSOE H.M. CANE	British Columbia Hydro and Power Authority
R.B. WALLACE 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. 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 E. Cheng R.W. Rerie	Commission Staff
T.M. Berry E. Switlishoff 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 • BCUC IR 1.3.7 • BCUC IR 1.36.1 • BCUC IR 1.91.1 • BCUC IR 3.178.5 • BCUC IR 3.181.4 • BCUC IR 3.184.3 • BCUC IR 3.191.1 • Sea Breeze IR 2.4.1 • Sea Breeze IR 2.13.2 • 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** CONFIDENTIAL -- Facsimile dated November 9, 2005 – Response to Commission Information Request No. 1.8.2 ***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 (2nd 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 ***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 ***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 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
	***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
	Withdrawn
C46-7	**COALITION TO REDUCE ELECTROPOLLUTION** – E-mail dated October 18, 2005 requesting Intervenor Status from Hans Karow
	***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
	***Previously C3-1 in Sea Breeze VIC proceeding**
C53-1	**HOLMAN, GARY** – E-mail dated October 18, 2005 requesting Intervenor Status
	***Previously C13-1 in Sea Breeze VIC proceeding**
C54-1	**GSX CONCERNED CITIZENS COALITION** – Notice of Intervention dated October 19, 2005 from Arthur Caldicott
	***Previously C16-1 in Sea Breeze VIC proceeding**
C55-1	**HARVIE, George**– Notice of Intervention dated October 18, 2005 (The Corporation of Delta)
	***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
	***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
	***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 ***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 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 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 ***Previously D-1 in Sea Breeze VIC proceeding**
D-70	**MOYSA, N.** – Letter dated October 14, 2005 requesting Interested Party Status ***Previously D-2 in Sea Breeze VIC proceeding**
D-71	Letter of Comment dated December 6, 2005 from the Bonneville Power Administration ***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

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
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E-6	Letter of Comment dated April 10, 2005 from Ted Bishop
E-6-1	Pending – submission at Salt Spring Town Hall Meeting

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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 Emails dated November 3, 2005 between Terry Treasure & Richard Berg ***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 **WITHDRAWN – replaced with Exhibit C40-7**

Exhibit No.	Description
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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
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E-27	Letter of Comment submission at Salt Spring Town Hall Meeting from Kim Hoban
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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
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E-64	Submission at Tsawwassen Town Hall Meeting by John Noble
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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
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Tab 2

Emera Brunswick Pipeline Co. (Re), 2007 LNCNEB 3

Case Name:

Emera Brunswick Pipeline Co. (Re)

IN THE MATTER OF Emera Brunswick Pipeline Company Ltd.
IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder; and
IN THE MATTER OF an application by Emera Brunswick Pipeline Company Ltd. (EBPC) dated 23 May 2006 for a Certificate of Public Convenience and Necessity under section 52 of the National Energy Board Act authorizing EBPC to construct and operate the Brunswick Pipeline, an Order under Part IV of the NEB Act approving the tolls for the Brunswick Pipeline and an Order designating EBPC a Group 2 company, filed with the National Energy Board under File No. OF-Fac-G-E236-2006-01 01 (3200-E236-1); and
IN THE MATTER OF National Energy Board Hearing Order GH-1-2006 dated 9 June 2006;
Re: Facilities and Tolls and Tariffs

2007 LNCNEB 3

No. GH-1-2006

Canada National Energy Board
Saint John, New Brunswick

Panel: S. Leggett, Presiding Member; K. Bateman, Member; S. Crowfoot, Member

Heard: November 6-11, 13-18 and 20, 2006.
Decision: May 2007.

(349 paras.)

Appearances:

Applicant:

Mr. Laurie Smith, Q.C., Mr. Nick Gretener and Mr. Peter Doig: Emera Brunswick Pipeline Company Ltd.

Companies:

Mr. Bernard Roth: Bear Head LNG Corporation, Anadarko Canada LNG Marketing, Corp. and Anadarko LNG Marketing, LLC (collectively "Anadarko").

Mr. David S. MacDougall: Enbridge Gas New Brunswick.

Mr. Ron Moore: Imperial Oil Resources and ExxonMobil Canada Ltd.

Mr. David A. Holgate: (collectively "Imperial").

Mr. James H. Smellie: Irving Oil Limited.

Mr. Peter C.P. Thompson, Q.C.: Repsol Energy Canada Ltd.

Mr. Robert Gall: Shell Canada Limited.

Dr. Darrell Gallant: 504-474 N.B. Ltd.

Groups:

Ms. Teresa Debly: Concerned Citizens, Friends of Saint John Community, Teresa Debly and the Estate of A.J. Debly (collectively "Teresa Debly").

Mr. Alan Ruffman, Mr. David Thompson and Mr. Eugene Gould: Friends of Rockwood Park.

Ms. Anne-Marie Mullin: South Central Citizens Council / House of Tara.

Individuals:

Ms. Teresa M. (Terry) Albright: (represented by Mr. Ivan Court).

Ms. Carol Armstrong.

Mrs. Dawn Baldwin.

Mr. Bernard Ball.

Mr. Philip Blaney.

Mr. Michael Burgess.

Mr. Ivan Court.

Mr. Patrick B. Court.

Mr. Charles L. Debly.

Ms. Janet Dingwell.

Ms. Janice Eldridge-Thomas.

Ms. Deborah Fuller.

Mr. Glenn Patrick Griffin.

Mr. Edward Harned.

Ms. Patricia Higgins.

Ms. Frauke Humphrey.

Dr. Tom Inkpen.

Mr. James L. Laracey.

Ms. Betty Lizotte.

Dr. Robert Moir.

Ms. Frances Oliver.

Ms. Joan Pearce.

Ms. Yvonne Perry.

Mr. Jack Quinlan.

Ms. Darlene Richard.

Ms. Ernestine Rooney.

Mr. Horst Sauerteig.

Ms. Linda Stoddard.

Dr. Leland.

T. Thomas.

Ms. E. Jean Thompson.

Governments:

Mr. Jake Harms: Environment Canada.

Mr. Paul Vanderlaan: New Brunswick Department of Environment.

Mr. Dan Robichaud: NDP and Dan Robichaud.

Mr. Stephen McGrath: Nova Scotia Department of Energy.

Ms. Jody Saunders and Ms. Marian Yuzda: National Energy Board.

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Approximate Conversions

1 metre (m)	=	3.28 feet
1 kilometre (km)	=	0.62 miles
1 cubic metre (m[superscript 3])	=	35.3 cubic feet
1 gigajoule (GJ)	=	0.95 million Btu (MMBtu)
1 decatherm (Dth)	=	1.0 MMBtu
1 hectare (ha)	=	2.47 acres
1 000 kilopascal (kPa)	=	145 psi
1 000 cubic metres (m[superscript 3])	=	38.86 gigajoules

Abbreviations

AFUDC: allowance for funds used during construction

Anadarko: Bear Head LNG Corporation, Anadarko Canada LNG Marketing, Corp. and Anadarko LNG Marketing, LLC

Bercha QRA Report: "Quantitative Risk Analysis of the Proposed Brunswick Natural Gas Pipeline" prepared by Bercha International Inc.

Bercha: Bercha Engineering Limited

CE Advisors: Concentric Energy Advisors

CEA Act: *Canadian Environmental Assessment Act*

CEA Agency: Canadian Environmental Assessment Agency

CMA: Census Metropolitan Area

Crossing Regulations: *National Energy Board Pipeline Crossing Regulations*

CSA: Canadian Standards Association

CSA Z662-03: CSA standard Z662-03, *Oil and Gas Pipeline Systems*

Dth/d: decatherm per day

DEGT: Duke Energy Gas Transmission

de Stecher Study: "Impact of Natural Gas Pipelines on the Value of Residential Real Estate" prepared by de Stecher Appraisals Ltd.

EA: environmental assessment

EBPC or the Applicant: Emera Brunswick Pipeline Company Ltd.

EGNB: Enbridge Gas New Brunswick

EMO: emergency management organization

EPM: emergency procedures manual

EPP: environmental protection plan

EPRP: emergency preparedness and response program

EPZ: emergency planning zone

ERP: emergency response plan

FA: federal authority

FORP: The Friends of Rockwood Park

FSA: firm service agreement

FTE: full-time equivalent

GDP: gross domestic product

Government Response: Response of the Government of Canada to the EA Report

HDD: horizontal directional drilling

Imperial: Imperial Oil Resources and ExxonMobil Canada Ltd.

IPL: international power line

Irving Oil: Irving Oil Limited

J.D. Irving: J.D. Irving, Limited

km: kilometre

KP: kilometre post

kPa: kilopascal

LDC: local distribution company

LNG: liquefied natural gas

LOC: letter of commitments

m: metre

MJ/m[superscript 3]: megajoules per cubic metre

M&NP: Maritimes & Northeast Pipeline Management Ltd.

M&NP US: Maritimes & Northeast Pipeline, L.L.C.

MDTQ: maximum daily transportation quantity

mm: millimetre

MPa: megapascal

NB: New Brunswick

NB ESA: *New Brunswick Endangered Species Act*

NB Power: New Brunswick Power Transmission Corporation

NEB Act: *National Energy Board Act*

NEB EA Report: National Energy Board Environmental Assessment Report

NEB or Board: National Energy Board

NSDOE: Nova Scotia Department of Energy

OD: outside diameter

OPR-99: *Onshore Pipeline Regulations, 1999*

Pembina Infrastructure Report: "Impacts of the Proposed Brunswick Pipeline on Municipal Infrastructure Maintenance Costs in Saint John" prepared by Pembina Institute

PPV: peak particle velocity

(the) Project: the proposed Brunswick Pipeline Project

RA: responsible authority

Repsol: Repsol Energy Canada Ltd.

RoW: right of way

SARA: *Species at Risk Act*

SCADA: supervisory control and data acquisition

SJFD: Saint John Fire Department

SJFD Risk Analysis Report: Risk Analysis report prepared by the Saint John Fire Department

SJL: Saint John Lateral

SOEP: Sable Offshore Energy Project

St. Clair: St. Clair Pipelines (1996) Ltd.

TEK: Traditional Ecological Knowledge

TransCanada: TransCanada PipeLines Limited

TWR: temporary working room

UNBI: Union of New Brunswick Indians

US: United States

Glossary of Terms

alternative means: the various ways that are technically and economically feasible that the project can be implemented or carried out

alternatives to: functionally different ways to meet the project need and achieve the project purpose

assignment of unused capacity: the transfer of the rights and obligations of a transportation contract held by one party - the **assignor** - to another party - the **assignee**

backhaul: either the "physical" transportation of natural gas in the reverse direction of a given pipeline, or a "paper transport" of natural gas by displacement against the flow on a single pipeline so that the natural gas is notionally delivered upstream of the point at which it enters the system

construction: construction includes all activities required to construct the Project, including all clearing activities

cumulative environmental effects: environmental effects that are likely to result from the Project in combination with projects or activities that have been or will be carried out (as defined in the CEA Act)

custody transfer station: a location where the quantity of gas is determined and the amount allocated to each shipper is established

demand charges: a monthly charge that normally covers the fixed costs of a pipeline; the demand charge is based on the daily contracted quantity and is payable regardless of quantities transported

environmental effect: in respect to a project, (a) any change that the project may cause in the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species as those terms are defined in section 2(1) of the *Species at Risk Act*, (b) any effect of any change referred to in paragraph (a) on health and socioeconomic conditions, on physical and cultural heritage, the current use of lands and resources for traditional purposes by Aboriginal persons, or any structure, site or thing that is of historical, archaeological, paleontological or architectural significance, or (c) any change to the project that may be caused by the environment (as defined in the CEA Act) exchange: transportation of natural gas by displacement over two separate pipelines, each of which takes and retains gas contractually allocated to the other

federal authority (FA): (a) a Minister of the Crown in right of Canada, (b) an agency of the Government or other body established by or pursuant to an Act of Parliament that is ultimately accountable through a Minister of the Crown in right of Canada to Parliament for the conduct of its affairs, (c) any department or departmental corporation set out in Schedule I or II to the *Financial Administration Act*, and (d) any other body that is prescribed pursuant to regulations made under paragraph 59(e) of the CEA Act (as defined in the CEA Act)

firm transportation: a non-interruptible gas transportation service which provides for the delivery of gas up to a specific maximum daily quantity; the shipper must pay a monthly demand charge regardless of the quantities transported and a commodity charge for the quantities actually transported

Group 2 Company: compared to Group 1 companies, Group 2 companies tend to be smaller and have very few shippers and are therefore subject to a lighter degree of financial regulatory oversight; they are regulated on a complaints basis

horizontal directional drill (HDD): a river, railroad, highway, shoreline and marsh crossing technique used in pipeline construction in which the pipe is installed under specified no-dig areas at depths usually greater than conventional crossings. An inverted arc-shaped hole with two sag bends is drilled beneath the no-dig area and the preassembled pipeline is pulled through it

interruptible transportation: a gas transportation service provided as capacity is available; the shipper only pays a toll for the quantities actually transported

launcher/receiver site: facilities used to launch and receive pipeline internal inspection and cleaning equipment

load factor: generally, the ratio of the average contract quantity to the maximum quantity available to be contracted for the same period, usually expressed over a year and as a percentage

meter station: a facility to monitor natural gas flow in pipeline systems (i.e., gas entering and leaving the pipeline system); meter stations may also allow for monitoring of natural gas quality

negotiated settlement: an agreement between a pipeline company and interested parties concerning issues related to the company's revenue requirement, tolls, tariffs, and operational matters

open access pipeline: a pipeline that offers non-discriminatory, fully equal access to its transportation services

open season: a process in which a pipeline company offers either existing or new capacity to the market and receives bids for that capacity from market participants

postage stamp toll: for pipelines, a toll that is charged per unit transported regardless of the distance traveled and the points of origin and destination responsible authority (RA): in relation to a project, a federal authority that is required pursuant to subsection 11(1) of the CEA Act to ensure that an environmental assessment of the project is conducted (as defined in the CEA Act)

right of way (RoW): the area which must be cleared (vegetation), crossed (watercourse), or developed (land) for the purpose of installing a pipeline

rolled-in toll: Tolls resulting from a toll design methodology in which the capital and operating costs of new facilities are added to those of the existing facilities; i.e., there is one cost pool for all facilities. Tolls are designed to recover the annual cost of providing service. All shippers who receive the same service pay the same toll. Tolls only vary according to such factors as volume and distance.

shipper: one who contracts with a pipeline for transportation of natural gas

Species at Risk: all species listed in Schedule 1 of the *Species at Risk Act* (SARA) as "extirpated", "endangered", or "threatened", or listed by the *New Brunswick Endangered Species Act* (NB ESA) as "endangered" or "regionally endangered"

Species of Conservation Concernspecies not under the protection of the SARA or the NB ESA; that is, listed in the SARA but not as "extirpated", "endangered", or "threatened" in Schedule 1; listed as "species of special concern" within Schedule 1 of the SARA; or ranked as "S1", "S2", or "S3" by the Atlantic Canada Conservation Data Centre and also ranked as "at risk", "may be at risk", or "sensitive" by New Brunswick Department of Natural Resources

swaps: see "exchange" - in the context of this document and application, the term swap is defined synonymously with an exchange transaction

tariff: the terms and conditions under which the services of a pipeline are offered or provided, including the tolls, the rules and regulations, and the practices relating to specific services

throughput: in general, the amount of gas being transported through a pipeline or being processed through a facility over a given period of time

toll: the price charged by a pipeline company for transportation and other services

turn back capacity: a reduction in a shipper's firm capacity commitments on a pipeline

Chapter 1

Introduction

1.1 Project Overview

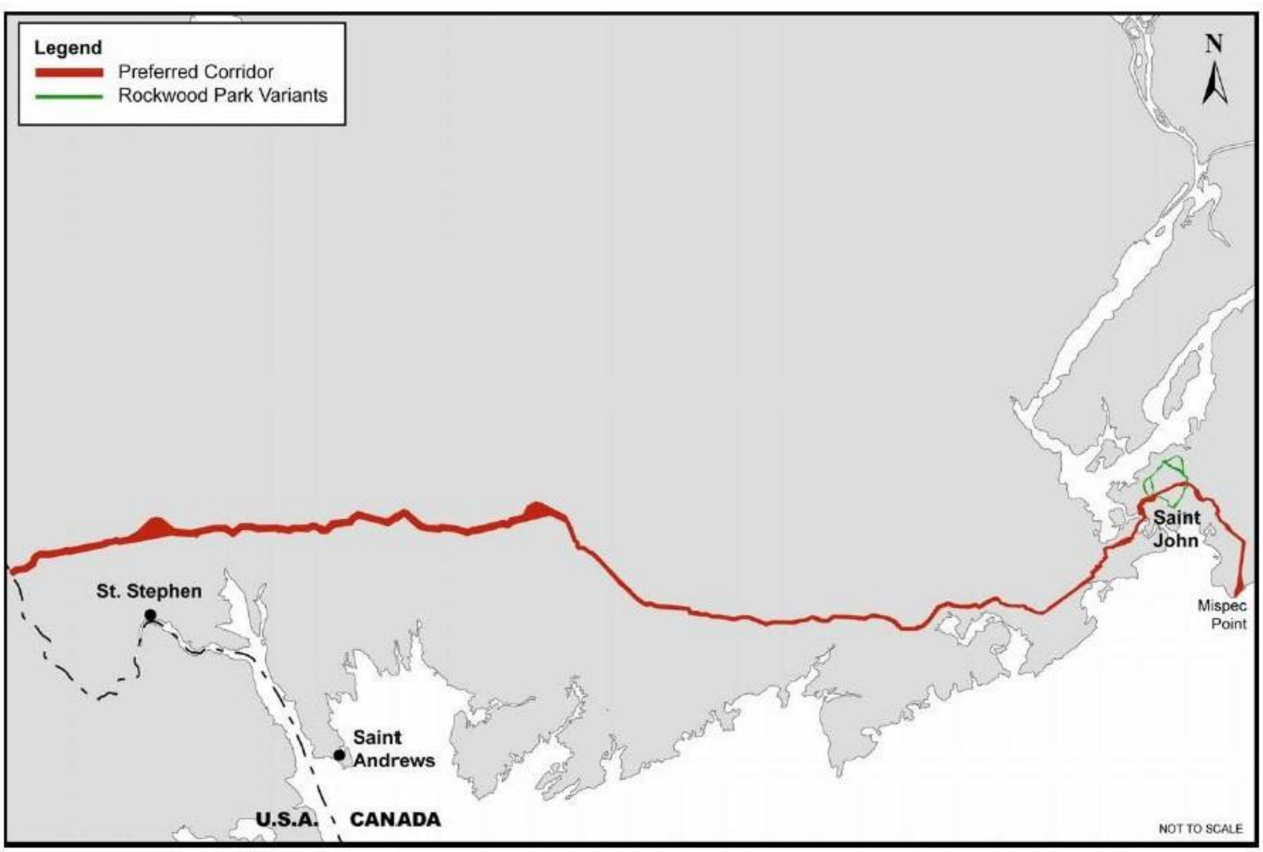
1 On 23 May 2006, Emera Brunswick Pipeline Company Ltd. (EBPC or the Applicant) applied to the National Energy Board (NEB or Board) for a Certificate of Public Convenience and Necessity under section 52 of the *National Energy Board Act* (NEB Act) authorizing EBPC to construct and operate the Brunswick Pipeline, an Order under Part IV of the NEB Act approving the tolls for the Brunswick Pipeline and an Order designating EBPC a Group 2 company.

2 The Brunswick Pipeline Project was referred to a review panel pursuant to section 25 of the *Canadian Environmental Assessment Act* (CEA Act). The NEB process was used as a substitute for an environmental assessment by a review panel as provided for under section 43 of the CEA Act. The substitution was approved by the Minister of the Environment and Minister responsible for the Canadian Environmental Assessment Agency (CEA Agency).

3 The proposed facilities would consist of approximately 145 km of 762 mm outside diameter (OD) pipeline extending from the Canaport[TM] Liquefied Natural Gas (LNG) Terminal at Mispec Point, New Brunswick (NB) to a point on the international border near St. Stephen, NB where it would interconnect with Maritimes & Northeast Pipeline, L.L.C. (M&NP US) (see Figure 1-1). The total capacity of the Brunswick Pipeline would be approximately 900 000 gigajoules per day (GJ/d) with a receipt pressure of 9 930 kPa at the interconnection with the Canaport[TM] LNG Terminal and a delivery pressure of 6 909 kPa at the interconnection with M&NP US. EBPC expects that the sales gas would have a heat content of 38.86 MJ/m[superscript 3].

Figure 1-1

Emera Brunswick Pipeline Project



4 EBPC proposes to begin construction clearing in late 2007, followed by pipeline construction to meet a target in-service date of 1 November 2008.

5 The Applicant estimates the total capital cost of the applied-for facilities to be approximately $350 million (see Appendix III for details).

6 EBPC and Repsol Energy Canada Ltd. (Repsol) have signed a Firm Service Agreement (FSA) for the firm transportation of 791 292 GJ/d on the Brunswick Pipeline for a term of 25 years. In addition to the FSA, the parties have executed a 25-year toll agreement obligating Repsol to pay all fixed charges applicable to the Brunswick Pipeline over the first 25 years of operation, including an investment return.

1.2 Environmental Assessment Process

7 The substitution provisions in section 43 of the CEA Act allow a federal authority (FA), with the approval of the Minister of the Environment, to use its own process for assessing the environmental effects of a project as a substitute for an environmental assessment (EA) by a review panel under the CEA Act. In the case of the Brunswick Pipeline Project, the Minister's approval allowed the NEB's public hearing process to substitute for an EA by a review panel under the CEA Act. The requirements for the substituted process were set out in correspondence among the CEA Agency, the NEB, and the Minister of the Environment. This correspondence and the scope of the EA are included in the NEB's EA Report, attached in full as Appendix VII to these Reasons.

8 Under the CEA Act, the Board conducted a review of the environmental effects of the Project and the appropriate mitigation measures. The Board's conclusions and recommendations, including mitigation measures, follow-up programs and its rationale, are set out in the NEB's EA Report. The EA Report also provides a summary of comments received from the public. The EA Report was released on 11 April 2007 and forwarded to federal responsible authorities (RAs). The response of the Government of Canada to the EA Report (government response) was coordinated by Natural Resources Canada and was approved by the Governor in Council pursuant to subsection 37(1.1) of the CEA Act on 17 May 2007.

9 A discussion of the government response is provided in Chapter 6 of these Reasons, and a copy of the government response is provided in Appendix VIII.

10 The Board took into consideration the EA Report and the government response before making its decision under the NEB Act. The Board's overall conclusion and disposition are provided in Chapter 9 of these Reasons. The conditions for inclusion in the Certificate are listed in Appendix V.

Chapter 2

Role of the Board

2.1 Public Participation

11 The Board is committed to ensuring that stakeholders are engaged effectively in the Board's public processes.[1] EBPC's application attracted a large public response with more than 70 parties registered as intervenors in the GH-1-2006 hearing, over 180 Letters of Comment received by the Board, and oral statements made by 19 people during the oral portion of the hearing.

12 As a result of the high level of public interest and the general lack of familiarity with the Board's processes, Board staff held a number of public information sessions and pre-hearing planning sessions to discuss Board processes, but not the merits of the application. In addition, the Board provided a Hearing Order setting out the procedure to be followed in this hearing, and written procedural updates, including one entitled "What Can I Expect at the Hearing" just prior to the oral portion of the hearing, to address common requests for information on the Board's processes or to further explain the oral portion of the hearing process. Throughout the written and oral portions of the hearing, Board staff responded to numerous procedural inquiries by telephone, email and in person. The Board also provided additional guidance to parties on its mandate and its process by way of its frequent rulings on motions made by parties throughout the course of the hearing; a number of these rulings are included in Appendix VI.

13 To further enable the participation of the public, the Board posted all documents received, to the extent it was technically feasible, on its electronic repository, accessible through the Board's Internet site. During the oral portion of the hearing, the Board viewed all documents being referenced electronically, on screens provided on the sides of the room, to enable the participants to follow the proceedings. The Board provided one hard copy of all exhibits, a computer and a printer in the hearing room for reference and use by participants to the hearing. The Board also broadcast its proceedings live, in both English and French, through its webcast of the proceedings, also accessible through the Board's Internet site. Additional technical or procedural assistance for parties, such as photocopying and blank affidavit forms, was provided by Board staff when requested, to the extent it was possible to do so. The Board also undertook service of intervenors' final arguments on other parties, if requested to do so.

14 In addition to the Board's activities aimed at ensuring effective public participation, the Board notes that there is also a responsibility upon the participants in an NEB public hearing. That responsibility is to attempt to participate in an effective manner, by following the procedures of the Board, being knowledgeable about the application and issues in the proceeding, providing relevant evidence for the Board's consideration, and, even in the face of disagreement with the position that another party advocates, showing courtesy and respect to all parties involved in the process, as well as to the Board and its staff.

15 In this proceeding, there was a high level of participation by intervenors, many of whom, though unpaid and unrepresented by counsel, were well-prepared and knowledgeable about the issues to be considered at the hearing.

2.2 Mandate of the National Energy Board

16 In addition to the activities undertaken by the Board during the hearing, the Board will, in these Reasons for Decision, provide guidance with respect to the role of the Board and its legal obligation to proceed in accordance with the principles of natural justice in considering EBPC's application. In the Board's view, it is especially important in the context of this particular hearing, in which the Board's public hearing process has been authorized to substitute for a review panel hearing under the CEA Act, that all parties clearly understand the responsibility of the Board, as mandated by Parliament and supervised by the courts.

17 The NEB is an independent federal agency that regulates several aspects of Canada's energy industry. It is a creature of statute, established in 1959 by Parliament by virtue of the proclamation of the NEB Act. The Act transferred to the Board the federal government's responsibilities[2] for pipelines from the Board of Transport Commissioners, and for oil, gas and electricity exports from the Minister of Trade and Commerce. In addition, it granted the Board responsibility for regulating tolls and tariffs, and defined its jurisdiction and status as an independent court of record.

18 The NEB's purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest in its regulation of pipelines, international power lines and energy development, within the mandate set by Parliament. As part of its mandate, the Board, as a quasi-judicial tribunal, may hold public hearings in order to hear all sides and points of view prior to making decisions on applications for new facilities that fall within its jurisdiction.

19 In carrying out its quasi-judicial duties, the Board is bound by its mandate under the NEB Act. In certain instances, such as this one, the Board also has responsibilities under the CEA Act. Under the NEB Act, there is no provision for participant funding. Under the CEA Act, participant funding is authorized, and in this case, a number of intervenors received such funding. As further discussed in the EA Report, attached as Appendix VII, the funding was administered by the CEA Agency, independent of the Board.

20 As a consequence of it being a creature of statute, the Board can only act within the mandates set out by the Acts pursuant to which it has responsibilities. The Board has no authority to intervene in matters which fall within the responsibility of the provinces, or of the municipalities. Throughout the hearing, the Board was provided with information concerning matters falling within provincial or municipal responsibility, and was made aware of the level of concern and frustration a number of members of the public had with these matters. Although the Board acknowledges that parties have these concerns, such matters are outside the Board's authority as set out in the NEB Act, or under the CEA Act.

21 The Board is bound as well by the principles of natural justice, under the supervision of the courts of law. These principles have been developed by the courts over centuries, and apply to any public body making a decision that affects the rights, privileges or interests of any person, other than a purely legislative decision.[3] Accordingly, the Board is legally required to adhere to these principles in carrying out its decision-making responsibilities.

22 Decisions by regulatory tribunals, such as the NEB, are not made by conducting a plebiscite or merely on the basis of a demonstration of public opposition or support. Rather, such decisions are made within a legal framework enacted by the legislature and applied by the courts. This is, of course, the essence of the rule of law.

23 In this case, part of the applicable legal framework is found in Part III of the NEB Act, section 52 of which requires the Board to make a determination with respect to "the present and future public convenience and necessity", in the Canadian public interest. Part IV of the NEB Act also requires that the Board make certain determinations with respect to tolls and tariffs. The requirement imposed by the courts is that, in making its determinations, the Board must rely only on the facts that are established to its satisfaction through the hearing process, and must otherwise proceed in compliance with the principles of natural justice. The Board must perform its duty on the basis of principle within a structured framework, while following a process that meets the requirements imposed by the courts. The principles of natural justice are further expanded upon in Subsection 2.3, below.

24 As previously mentioned, in this application, EBPC has applied under two parts of the NEB Act - Part III, Construction and Operation of Pipelines; and Part IV, Traffic, Tolls and Tariffs. The different Parts of the NEB Act require different determinations to be made by the Board. In Part III, under section 52 of that Part, the Board has to make a determination whether the Project is in the present and future public convenience and necessity. Under Part IV, the Board must determine whether the tolls to be charged are just and reasonable, and ensure that there is no unjust discrimination with respect in tolls, service or facilities. Much of the general public's interest in this hearing stemmed from EBPC's Part III application to construct and operate the Brunswick Pipeline. Accordingly, further explanation of how Part III applications are assessed may be informative. This is found in subsection 2.4, below.

25 The Board is only charged under Part III with determining whether the Project applied-for, involving the preferred corridor, is in the present and future public convenience and necessity. The Board is not able to approve a different corridor, such as one that includes a proposed marine portion of the corridor. However, in determining whether the Project is or is not in the present and future public convenience and necessity, the Board will consider, among other factors, the appropriateness of the general route and general land requirements (Issue 7 of the List of Issues), as well as any public interest that in its opinion may be affected by the granting or refusing of the application (Subsection 52(e) of the NEB Act). Accordingly, further discussion of the marine corridor is contained within Chapter 6 herein, as well as being discussed under the Board's CEA Act mandate in the Board's EA Report, attached as Appendix VII hereto.

2.3 Principles of Natural Justice

26 Natural justice has been explained in the jurisprudence as follows:[4]

> The concept of natural justice is an elastic one, that can and should defy precise definition. The application of the principle must vary with the circumstances. How much or how little is encompassed by the term will depend on many factors; to name a few, the nature of the hearing, the nature of the tribunal presiding, the scope and effect of the ruling made.

27 As a result, the content of the principles of natural justice will vary from case to case. Essentially, what is "fair" requires a balance between what is necessary for the effective and efficient performance of public duties, as mandated under an empowering statute, and what is necessary for the protection of the interests of the parties affected.[5]

28 Generally, there are two components to the principles of natural justice. First, a party must have an adequate opportunity to be heard before a decision is made affecting that party's interest. The second component is that the decision must be made by an independent and unbiased decision-maker.[6]

29 Allowing a party an adequate opportunity to be heard before a decision is made affecting that party's interest requires that all parties know the case that is to be met and be provided with the opportunity to respond fully and defend their own position. It also requires that the decision be made on the basis of evidence presented, and not on the basis of perception, impression, anecdote or merely the number of people in opposition to, or in support of, an application. Further, such a decision must be made by an independent decision-maker who is objective and impartial.

30 Consequently, anyone submitting to the Board an application for a facility with the requisite information has a legal right to a full and fair hearing before the Board. An applicant is then legally entitled to a decision by the Board based on the facts and evidence presented at such a hearing, in accordance with the statutory requirement on the Board under Part III to determine whether an applied-for facility is and will be required by the present and future public convenience and necessity.[7]

31 Natural justice also requires, among other things, that notice be given to other parties whose interests may be affected by an application, so that those parties who wish to participate in a hearing to test the applicant's evidence, provide their own evidence, and provide final argument, have the opportunity to do so. The Board's hearing process is designed to meet its legal obligation to comply with the principles of natural justice.

32 The Board notes that there is a responsibility on parties who wish to participate in a hearing, to do so in a timely manner, and in accordance with the rules established for the hearing. Late attempts to participate or to provide evidence past the deadlines established could not only be disruptive to the process, but, if permitted, could impact the procedural rights of the existing parties. Therefore, the Board was very cautious in determining, on the facts of each request, whether that request for late participation or to file late evidence, in that particular circumstance, may be beneficial to the Board in making its decision, and was not in contravention of the principles of natural justice or unduly prejudicial the rights of other parties.[8]

2.4 Assessing a Facilities Application under Part III, section 52 of the NEB Act

33 When the Board receives an application to construct and operate a facility, it must initially evaluate whether the application is ready to proceed to a public hearing. The Board does this by assessing the information provided in the application against the information required by the Board's Filing Manual (2004). If the Board is satisfied that the application meets these threshold requirements for the purposes of a hearing, it issues a hearing order. It is not expected that all of the evidence that the Board will require to make its decision will be provided in the initial application to the Board. Instead, one or more rounds of information requests are undertaken. In addition, there are further written filings both by the applicant and by other parties, the eliciting of oral evidence through questioning on the pre-filed written evidence at the oral portion of the hearing, and potentially oral statements made at the oral portion of the hearing, to ensure that the Board has as complete a record as possible upon which to base its decision.

34 At the end of the evidentiary portion of a hearing, all parties have the opportunity to present final argument based upon the evidence before the Board. Final argument provides parties the opportunity to persuade the Board of their position, based on the evidence that has been previously adduced. It is not the time for providing new evidence, as this would be contrary to the principles of natural justice previously discussed. Sometimes final argument contains statements or comments that are not supported by the evidence on the record. The Board's role in reviewing the evidence and arguments is to ensure that statements and comments made in argument are supported by the evidence on the record, to disregard any statements that are not so supported, and to make its determination based solely on the record. To do otherwise would breach the principles of natural justice.

35 The Board notes that this level of information is required for the Certificate of Public Convenience and Necessity stage of a project, during which the applicant is seeking approval only for a broad corridor, within which corridor the final, smaller right of way (RoW) and pipeline would be located if the project obtains all of its approvals. It is not necessary that every detail related to a project be put before the Board for the purpose of the Board's determination whether to grant or deny the application for a Certificate. The nature of applications presented to the Board is such that not every detail of a project must be ascertained before a Certificate may be issued; indeed it would be impractical, if not impossible, for all details to be provided in advance.

36 At this Certificate stage of a project, an applicant has the onus of persuading the Board that a Certificate should be issued on the basis of all of the evidence presented during the course of both the written and oral portions of the hearing. While it is up to the applicant to provide evidence in support of its application, intervenors opposing the application are expected to provide some form of evidentiary support for their position. Intervenor evidence may then be subject to the same testing as the applicant's evidence, for example, by cross-examination at the oral portion of the hearing.

37 The Board notes that prior to a pipeline project being put into operation, there are a number of additional approvals that must be issued and detailed filings required, which involve, for example, the filing of the plans, profiles and books of reference setting out the detailed route of the pipeline, the filing of various detailed construction, operational, and environmental manuals, other filings required as part of condition compliance or to comply with applicable regulations, and approval of a leave to open application. Further information and approvals may also be required by other federal, provincial or municipal regulatory agencies.

38 In addition, should a project be approved, the Board has the authority and responsibility to monitor the company's activities during the construction and operation phases of that project to ensure pipeline safety, and also to ensure that a company is abiding by all of the terms and conditions of its Certificate and the applicable regulations under the NEB Act. For example, during construction, the Board inspects the project, ensuring condition compliance and responding to landowner complaints. To address any noncompliance matters, the Board has various levels of enforcement tools available, up to and including stop work orders and revocation or suspension of the Certificate.

39 After construction, the Board retains jurisdiction over an approved project, assuming a supervisory and regulatory role for the life of the project. In this role, the Board ensures ongoing compliance with both Certificate conditions and applicable legislation under which the Board has a legislated mandate. As well, the Board deals with any complaints that arise during the life of the project and fall within the Board's jurisdiction.

40 The GH-1-2006 hearing provided an opportunity for the Board to hear the views of people who may be affected by the Brunswick Pipeline Project. In addition, those people who were granted intervenor status had an opportunity to ask written questions about the evidence on the record, ask questions directly of EBPC's witnesses, file evidence of their own and respond to questions on that evidence. Intervenors also had the opportunity to present arguments to the Board and respond to the arguments of the Applicant. In the Board's view, the combined written and oral portions of the GH-1-2006 hearing provided a complete record upon which the Board has based its final decision, under Part III of the NEB Act, whether the Brunswick Pipeline Project is and will be in the present and future public convenience and necessity, as well as under Part IV, with respect to traffic, tolls and tariffs on the Brunswick Pipeline.

2.5 Public Interest and the Public Convenience and Necessity Test under Part III of the NEB Act

41 The Board has described the public interest in these terms:[9]

> The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision.

42 As a federal tribunal, the Board must focus on the overall Canadian, or national, public interest. Various decisions of the courts have established that a specific individual's or locale's interest is to be weighed against the greater public interest, and if something is in the greater public interest, the specific interests must give way.[10]

43 Throughout the jurisprudence and commentary on "public convenience and necessity" and "public interest", the phrase "public convenience and necessity" has generally been treated as being synonymous with "public interest".[11] The public convenience and necessity test is predominantly the formulation of an opinion by the tribunal. This opinion must be based on the record before it; that is to say, the decision must be based not only on facts but with the exercise of considerable administrative discretion.[12] Similarly, there are no firm criteria for determining the public interest that will be appropriate to every situation. Like "just and reasonable" and "public convenience and necessity", the criteria of public interest in any given situation are understood rather than defined and it may well not serve any purpose to attempt to define these terms too precisely. Instead, it must be left to the Board to weigh the benefits and burdens of the case in front of it.

44 The Board has often incorporated these concepts into its own decision-making process; for example, it has stated that the test of public convenience and necessity is primarily a matter of reasoned opinion, based upon an appropriate factual basis that is within the discretion of the regulatory body.[13]

45 With respect to how these concepts apply to the Board in fulfilling its mandate under the NEB Act, it is noteworthy that Parliament did not find it necessary to specify how the factors set out in section 52, including how paragraph 52(e) [public interest], or any other factors that the Board might consider relevant, are to be examined and applied. The

Board has the discretion to decide what factors are relevant in determining the public interest under the NEB Act. For example, the CEA Act requires a consideration of socio-economic effects only if they result from an environmental effect of a project. The Board usually considers a broader range of socio-economic effects when considering an application under the NEB Act.[14] Under paragraph 52(e) [public interest] of the NEB Act, the Board has, in the past, also taken into account other considerations related to the project, such as potential for commercial impacts, environmental protection and public safety.[15] In certain cases, the Board has also considered whether the addition of pipeline facilities to the existing Canadian pipeline infrastructure was in the public interest.[16]

46 Since the public interest is dynamic, varying from one situation to another (if only because the values ascribed to the conflicting interests alter), it follows that the criteria by which the public interest is served may also change according to the circumstances.[17] In addition, it is worthwhile to note that while the Board may be guided by past decisions, it need not be bound by them; indeed, it may be imprudent to be so bound given the dynamic nature of the public interest, and the inherent exercise of administrative discretion in the Board's decision-making process.

47 While in certain cases the unequivocal failure of an applicant to satisfy the Board on a single critical component may be enough for the Board to conclude that, on that fact alone, the project cannot be found to be in the public convenience and necessity, such failure on a single factor is unlikely. More common is the situation where the evidence in one or more of the areas of examination is stronger than that presented with respect to other relevant matters.[18] In such cases, the Board will, on the basis of the evidence before it and within the specific circumstances of each application, apply administrative discretion and expertise in its overall determination of whether the applied-for pipeline is required by the present and future public convenience and necessity. In doing so, the Board must also, after carefully weighing all of the evidence in the proceedings, exercise its discretion in balancing the interests of a diverse public.

48 Accordingly, under the NEB Act, the factors to be considered and the criteria to be applied in coming to a decision on public interest or the present and future public convenience and necessity may vary as a result of many things, including the application, the location, the commodity involved, the various segments of the public affected by the decision, societal values at the time, and the purpose of the applicable section of the NEB Act. The following subsections and chapters discuss, among other things, the Board's identification, consideration, weighing and balancing of those factors the Board has determined are relevant to its assessment of this particular Project under section 52 of the NEB Act.

2.6 Applying the Test in the GH-1-2006 Hearing to EBPC's Part III Application

49 During the course of this hearing, several parties raised the public convenience and necessity test, and the criteria that the Board should consider in making its decision in the public interest.

50 Section 52 states as follows:

> 52. The Board may, subject to the approval of the Governor in Council, issue a certificate in respect of a pipeline if the Board is satisfied that the pipe-

> line is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate, the Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:
>
> (a) the availability of oil, gas or any other commodity to the pipeline;
> (b) the existence of markets, actual or potential;
> (c) the economic feasibility of the pipeline;
> (d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and
> (e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

51 The effect of the language in section 52 is that the Board has broad discretion. Based on the decision of the Federal Court of Canada in *Union Gas* v. *TransCanada PipeLines Ltd.*,[19] the only apparent limit on the exercise of that discretion is good faith, although the Board must, of course, exercise its discretion on the basis of relevant considerations and not arbitrarily or discriminatorily.[20]

52 In *Canadian National Railways* v. *Canada Steamship Lines Limited,*[21] the Privy Council, in construing the words "all considerations which appear to it to be relevant", which are the same words as used in section 52 of the NEB Act, held:

> It would be difficult to conceive a wider discretion than is conferred on the Board as to the considerations to which it is to have regard in disposing of an application for the approval of an agreed charge. It is to have regard to "all considerations which appear to it to be relevant". Not only is it not precluded negatively from having regard to any considerations, but it is enjoined positively to have regard to every consideration which in its opinion is relevant.

53 While the factors that the Board will consider may vary in the circumstances of the case before it, there are certain factors that are typically addressed in pipeline applications. For example, public safety, environmental, and socio-economic concerns are usually raised in the context of public interest considerations, and were examined in this hearing as well.

2.7 Conclusion

54 In this proceeding, the Board heard evidence on engineering design and safety issues; economic considerations, such as supply and markets; public engagement and Aboriginal consultation; socio-economic and environmental effects of the Project; and land and routing matters. These issues are addressed in more detail in the following chapters. The Board has determined that all of these factors are relevant to its decision under Part III of the NEB Act, whether the Project is in the present and future public convenience and necessity. Accordingly, the benefits and burdens that would result from the Brunswick Pipeline Project in all of these areas must be identified prior to the Board's final determination of whether the Project is and will be required by the present and future public convenience and necessity. Chapters 3, 4, 5 and 6 discuss these issues and the associated benefits and burdens of these issues.

55 Chapter 7 addresses issues arising from EBPC's Part IV application with respect to the tolls and tariff on the Brunswick Pipeline Project. Additional benefits and burdens related to tolls, tariffs and service issues are also identified therein. The Board's determination on whether the tolls to be charged are just and reasonable, and whether there is unjust discrimination with respect to tolls, service or facilities, is contained in that chapter along with the Board's decision on EBPC's requested method of regulation.

56 The Board's weighing and balancing of all of the benefits and burdens of the Brunswick Pipeline Project, and its determination under Part III of the NEB Act is contained in Chapter 8 of these Reasons.

57 Its disposition with respect to EBPC's application is contained in Chapter 9.

Chapter 3

Facilities and Safety of Operation

3.1 Facilities Description

58 An overview description of the facilities is provided in Chapter 1. Additional details are set out below. The pipeline would be constructed in two sections, an urban section of approximately 31 km through the City of Saint John, NB beginning at the Canaport[TM] LNG Terminal, and a rural section of approximately 113 km extending from the City of Saint John to the M&NP US interconnect. The urban section includes approximately 4.2 km through Rockwood Park, and a planned horizontal directional drilling (HDD) crossing of the Saint John River.

59 Six mainline valve sites would be installed, each with a sectionalized block valve that can be operated either manually or by remote control from the Duke Energy Gas Transmission (DEGT) Houston gas control center. Three of the valve sites would be located within the City of Saint John, and three sites would be located along the rural section of the pipeline.

60 One custody transfer station would be installed on the Brunswick Pipeline at the interconnect point between the pipeline and the Canaport[TM] LNG Terminal.

61 The applied-for facilities include two sets of pig launcher/receiver facilities. A launcher would be installed at the interconnect between the Brunswick Pipeline and the Canaport[TM] LNG Terminal, and a launcher/receiver facility would be installed at the mainline valve site located adjacent to the Maritimes & Northeast Pipeline Management Ltd. (M&NP) Saint John Lateral (SJL) valve site 63. Although not part of this application, a receiver barrel would be installed in the United States (US) at the Baileyville Compressor station.

3.2 Pipeline Design

3.2.1 Codes and Standards

62 EBPC submitted that the applied-for facilities would be designed, constructed and tested in accordance with Canadian Standards Association (CSA) standard Z662-03, *Oil and Gas Pipeline Systems* (CSA Z662-03), the provisions of the NEB Act and other applicable governing codes. EBPC would also comply with the requirements of the *Onshore Pipeline Regulations, 1999* (OPR-99) for the construction, operation and maintenance of the pipeline. EBPC plans to conduct a 100 percent examination of all welds for the Project. Welding and testing would follow the requirements set out in CSA Z662-03. The pipeline would be tested in accordance with DEGT Procedure TP-CT1.0 dated 5 May 2004, "Pressure Testing of Gas Transmission Facilities", which complies with the requirements of both CSA Z662-03 and OPR-99.

3.2.2 Materials and Line Pipe

63 In its application, EBPC provided a detailed explanation of the specifications for the pipe and other proposed facilities for the Project. The pipe specifications are summarized in Appendix IV. EBPC stated "the Brunswick Pipeline will be a state-of-the-art natural gas pipeline, incorporating the latest in corrosion protection technology and built to standards often exceeding Code requirements."

64 A number of intervenors expressed concern about the thickness of the proposed pipeline and the possibility that it could be ruptured. However, EBPC submitted that the grades of steel and the pipeline thickness proposed for its pipeline were highly resistant to third party damage. It indicated that NEB standards for pipeline wall thickness were met or exceeded throughout the urban route. Further, EBPC stated that, based on a study it submitted entitled "Resistance to Puncture Pertaining to the Brunswick Pipeline" prepared by Kiefner & Associates, Inc., the risk of a third party event puncturing the urban pipeline would be remote.

3.3 Pipeline Construction

65 EBPC submitted that its development team has considerable experience designing, constructing and operating pipelines. EBPC had established a contractual relationship with St. Clair Pipelines (1996) Ltd. (St. Clair) to provide project management and technical services to permit and construct the Brunswick Pipeline, as well as to operate the Brunswick Pipeline once it is in service. EBPC stated that St. Clair has the most extensive pipeline construction and operating experience available in Maritime Canada as it was responsible for the design and construction of the M&NP system and is the contract operator of that system. EBPC indicated that, through St. Clair, it has also been able to access the considerable depth of experience of the DEGT staff, which operate natural gas pipeline transmission and gas distribution facilities across Canada and the US.

3.3.1 Blasting

66 EBPC anticipated a substantial portion of the proposed corridor would require mechanical ripping or blasting to excavate the pipeline trench. EBPC stated that most of the proposed urban corridor through the City of Saint John would require some degree of blasting.

67 EBPC proposed designing blasts to account for adjacent structures, facilities, and services and to use blast mats to prevent scattering of rock and debris. A concise blasting and blast monitoring protocol would be established and enforced in residential areas.

68 Blasts would be designed to limit vibration levels to 50 millimetres per second (mm/sec) at peak particle velocity (PPV). For vibration sensitive-structures, vibration would be limited to 25 mm/sec at PPV. Further, EBPC's contractor would conduct three test blasts based upon the blasting procedures prior to full scale blasting. If the test blasts do not produce an acceptably low level of vibration, the contractor would revise the blasting procedures.

69 EBPC committed to surveying all structures and facilities located within 200 m of the blasting zone both before and after blasting activities. Older homes in Milford would be assessed by a professional engineer to determine if they warrant a sensitive structure status. Claims for damage would be reviewed by comparing pre-blast surveys to post-blast surveys.

70 All existing groundwater wells within 500 m of blasting activity would be identified. EBPC indicated it would undertake seismic monitoring for the well situated closest to the RoW, within 500 m of each side of a blast, during blasting activities.

3.3.2 Horizontal Directional Drilling (HDD)

71 EBPC retained the specialized services of a consultant, AK Energy Services, to examine the feasibility of a number of HDD crossings along the corridors under review for the proposed pipeline. The crossing of the Saint John River between Pokiok and Pleasant Point attracted the most attention from participants during the proceeding. The most significant issues raised were noise and vibration, and the duration of construction. EBPC submitted that it plans to conduct this HDD during the winter construction season to avoid seasons during which residents would be more likely to keep their windows open throughout the day.

72 The issues and mitigation measures associated with HDD activity are addressed in the NEB's EA Report, which is attached in full as Appendix VII to these Reasons.

Views of the Board

The Board notes that St. Clair, to whom the construction and operation of the Pipeline has been contracted, has a great deal of experience in doing so, including direct experience in this locale.

The Board is satisfied with the measures that EBPC has proposed to minimize and mitigate the effects of blasting during construction. Adequate protection of vibration-sensitive structures will be provided by monitoring blasts within 200 m and limiting vibrations to 25 mm/sec PPV. In the event that any damage were to occur during blasting to sensitive structures, groundwater wells, or otherwise, the Board would expect EBPC to reassess the blast design before blasting activity continued. In light of the information EBPC has provided to date, the Board is satisfied that EBPC intends to continue to develop and implement appropriate construction methods to handle challenges faced during the HDDs. The Board finds that the commitments EBPC has made to monitor and control noise and vibration are sufficient. EBPC's commitment to hire experienced contractors to perform the HDDs provides further assurance to the Board that the HDDs can be carried out as EBPC has proposed. [For further discussion about noise related to HDDs, please see the NEB EA Report.]

3.4 Pipeline Safety

3.4.1 Risk Assessment

73 In support of its application, EBPC submitted a report titled "Quantitative Risk Analysis of the Proposed Brunswick Natural Gas Pipeline" prepared by Bercha International Inc. (Bercha QRA Report). The purpose of the Bercha QRA Report was to evaluate the risks associated with operating the proposed pipeline and, if required, to identify any appropriate mitigative measures to minimize the risks to acceptable levels. The principle conclusions were summarized in that report as follows:

* The individual risk levels to members of the public were within acceptable limits and in the Insignificant risk regions.
* None of the individual specific risks fall into the Intolerable risk region.
* The HDD portion of the pipeline presents somewhat lower risk than the buried portion of the pipeline.
* The preferred route through Rockwood Park presents lower risks to the public than the other two alternatives.
* The preferred route through Rockwood Park presents significantly lower risks to the Saint John Regional Hospital than the northern route alternatives, although all route alternatives are in the Insignificant risk region.

74 The Bercha QRA Report included a number of general recommendations for EBPC to consider. These are summarized below:

* Land use control on the RoW should be maintained.
* An emergency response plan should be developed in conjunction with emergency response agencies and public representatives to manage any possible emergency.
* The preferred route through Rockwood Park is recommended, as it poses significantly lower risks to the Saint John Regional Hospital than the northern alternatives.
* Use of an existing RoW, wherever possible, is strongly supported. The addition of this pipeline to a well-marked and well-know utility RoW provides added safety protection.

75 Several intervenors expressed concerns about the risk associated with having the proposed facilities built through the City of Saint John, and in particular, near institutions like the Saint John Regional Hospital and in close proximity to residences like those in the community of Champlain Heights. Intervenors questioned the validity of the Bercha QRA Report and felt that the scope, breadth, basis, and depth of the assessment were inaccurate and insufficient to suitably identify and quantify the risks the urban section of the line may impose on the City of Saint John.

76 Mr. Ivan Court submitted a risk analysis report that had been prepared by the Saint John Fire Department (SJFD Risk Analysis Report) and provided to Common Council in September 2006. Bercha Engineering Limited (Bercha) reviewed this report for EBPC and concluded that because the document had been prepared without adequate participation of pipeline and risk analysis experts, it contained numerous faulty statements and conclusions. EBPC submitted that it had discussed public safety, related to the preferred corridor, with the Saint John Fire Chief and that it had addressed all of the recommendations made within the SJFD Risk Analysis Report.

77 The Friends of Rockwood Park (FORP) submitted two independent reports critiquing the Bercha QRA Report. The first of these, "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick", was prepared by Richard Kuprewicz of Accufacts, Inc. That report concluded that the Bercha QRA Report was missing critical information to support or justify the risk transects determined for the on-land route through the City of Saint John. The second report, "Evaluation of *Quantitative Risk Analysis of the Proposed Brunswick Natural Gas Pipeline*, by the Bercha Group", was prepared by John Wreathall of John Wreathall & Co., Ltd. This report concluded that the Bercha QRA Report was deficient in several ways and failed to justify the claim that the risks from the pipeline would be insignificant.

78 Bercha addressed each of these reports on behalf of EBPC. It stated that both reports were general and vague with no quantitative substantiation for their claims. Bercha stated that the commentary in the Kuprewicz report was based on a generic interpretation of the QRA and other reports on pipelines, and Mr. Kuprewicz's lack of experience with pipeline risk analysis led to his incorrect and unsubstantiated claim that "immediate ignition of a pipeline rupture natural gas release is the worst case". With regard to the Wreathall report, Bercha stated that it offered only negative comments with no useful suggestions, and that Mr. Wreathall's lack of experience and competence with pipeline risk analysis led to his conclusion that "a significantly delayed ignition" was the worse case. Bercha submitted that both these claims were incorrect, and "in fact, for a rupture, the worst case initial flow rate occurs neither immediately nor late, but in the first few minutes."

79 In support of its view that "an underground transmission pipeline is by far the safest and most environmentally friendly way to transport large volumes of natural gas", and to allay the concerns of a number of intervenors over the safety of the Brunswick Pipeline, EBPC submitted "A Summary of Existing High Pressure Natural Gas Transmission Pipelines in High Density Urban Areas". EBPC submitted that the mapping examples it provided "clearly illustrate that critical infrastructure, residential and commercial developments, schools, hospitals, shopping malls and other public facilities in closer proximity to existing gas transmission pipelines operate in Canada and the US in a fashion similar to how the Brunswick Pipeline will operate." EBPC argued that this fact is "irreconcilable with the dire consequence assessments" offered in the SJFD Risk Analysis report, the Kuprewicz report and the Wreathall report.

80 EBPC stated that risks are identified, assessed and mitigated in the design, construction, testing and operation phases of a pipeline project. By meeting or exceeding all of the requirements for pipeline safety prescribed by government regulations and industry standards, the proposed Project would meet or exceed established "accepted risk" criteria.

Views of the Board

The Board is of the view that EBPC has taken an acceptable approach to identifying and assessing the risks associated with the urban and rural sections of the proposed Pipeline. The Board notes that the urban section of the proposed Pipeline has been designed for the requirements of a Class 3 location designation, which meets or exceeds the requirements of CSA Z662-03 for the types of development existing and anticipated along the pipeline route, including schools and institutions where evacuation may be difficult.

The Board accepts the Bercha QRA Report as accurately portraying the risks associated with this proposed project. The Board finds that the other risk assessment reports filed as evidence did not identify any critical issues which would cause the Board to question the conclusions contained within the Bercha QRA Report.

3.4.2 Quality Assurance and Integrity Programs

3.4.2.1 Quality Assurance Program

81 EBPC committed to following the DEGT Quality Assurance Program. The Quality Assurance Program would ensure that pipeline construction materials, and inspection and test procedures, would meet the specifications provided for in the pipeline design.

3.4.2.2 Pipeline Integrity Management Program

82 EBPC committed to adopt and augment as necessary the M&NP pipeline integrity management program. As described by EBPC, the pipeline integrity management program would employ a cycle of hazard identification, condition monitoring, mitigation of hazards, documentation, and feedback measures, including the following:

* internal inspection programs;
* investigative excavation programs;
* slope monitoring and surveillance;
* watercourse crossing inspections;
* cathodic protection surveys; and
* leak detection surveys.

83 In its reply evidence, EBPC described at length how operational hazards and threats would be managed as a component of its integrity management program. EBPC has committed to run an in-line inspection tool roughly three years after commencement of operation, and subsequent tool runs approximately every seven to ten years.

3.4.3 Operation

84 Many of the issues raised with respect to the operation of the proposed pipeline and the evidence on these issues were discussed in sections 7.2.1 and 7.2.4.1 of the NEB's EA Report, attached as Appendix VII to these Reasons. The following sections should be read in conjunction with those sections of the EA.

3.4.3.1 Control, Monitoring, and Leak Detection

85 Several participants expressed concern over the ability of EBPC to react to potential leaks of natural gas from the proposed pipeline.

86 EBPC responded that the pipeline would be controlled from DEGT's Gas Control centre located in Houston, Texas. Control would be carried out using a supervisory control and data acquisition (SCADA) system that continuously monitors the pipeline operation parameters and processes pressure and volumetric data measured at each valve and flow meter. Based on this data, the SCADA and leak detection system would relay the commands for the operation of the control system. EBPC indicated that Gas Control would be alerted of a potential issue by a rate of pressure change alarm. It estimated that it would likely take about five to six minutes to detect a rapid pressure drop on the SCADA system, make a decision to shut in the line, and initiate the closure passwords. Further, EBPC submitted that to ensure that loss of power or communications would not impact control center response, there would be back-up power and communications systems to ensure that pressure and flow monitoring at valve sites and related communications to transmit system information could continue.

87 Additionally, EBPC submitted that regular inspection of the RoW by trained personnel, emergency call numbers, as well as the addition of an odourant (mercaptan) to the gas, would ensure detection of leaks too small to be detected by the sensors in the line.

3.4.3.2 Emergency Preparedness and Response

88 EBPC committed to adopting and augmenting as necessary the M&NP Emergency Preparedness and Response Program (EPRP). The EPRP would include the following components:

- Introduction;
- Risk Assessment;
- Federal and Provincial Agency List;
- Agency Liaison Program;
- Public Continuing Education Program for Emergency Planning Zone (EPZ) Residents and First Responders;
- Emergency Preparedness Manuals;
- Training; and
- Validation and Emergency Exercises.

89 EBPC committed to undertaking a risk assessment upon completion of the detailed routing process to establish the size of the EPZ. The size of the EPZ would be equal to or less than 800 m, defined as a circle with the specified radius measured from the point of a pipeline incident. When extended for the length of the pipeline, the limits of the EPZ would parallel the pipeline at the specified distance on both sides of the pipeline.

90 Upon establishing an EPZ, EBPC indicated it would develop an accurate database identifying occupied structures within the EPZ. EBPC would develop and carry out its Continuing Education Program, targeting residents within the EPZ. This program would educate EPZ residents on pipeline location, potential emergency situations, safety procedures, the roles of residents, what to expect in the event of an emergency, and the actions of pipeline personnel and first responders. The Continuing Education Program would also target first responders, providing education on their duties and responsibilities, practices to ensure public and responder safety, assignment of clear roles, and chain of command.

91 EBPC has identified lead agencies that would be consulted after the detailed routing is substantially complete. These agencies were identified in the proceedings and are summarized in the NEB EA Report, and include the SJFD, Saint John City Police and Saint John Emergency Management Organization (EMO).

92 EBPC's Field Emergency Response Plan (ERP) would meet the Board requirement in the OPR-99 for an Emergency Preparedness Manual. The ERP for the Brunswick Pipeline would mirror the plan developed by M&NP for the SJL. EBPC committed to developing an ERP in accordance with NEB requirements and would prescribe measures to ensure effective and timely response to emergencies, and to protect the public. The ERP would:

* identify arrangements made to respond to pipeline incidents, including any mutual aid agreements made with outside agencies;
* outline roles and responsibilities related to emergency response;
* define notification and reporting requirements for incidents; and
* provide guidelines and site-specific emergency response procedures for operation and maintenance staff and emergency response agencies.

93 EBPC also committed to conducting emergency response exercises of varying scope, from table top exercises and internal field mock emergencies to full scale mock emergencies involving external agencies.

Views of Interested Parties

94 A number of intervenors were of the view that it was unacceptable to have critical infrastructure and facilities within the EPZ. Concerns were raised about facilities in close proximity to the proposed pipeline route, the potential for these facilities to be within the EPZ, and how a pipeline emergency would interact with critical structures within the EPZ. Through the proceedings many facilities and structures that could potentially fall within the EPZ were identified; for example, health care facilities, such as the Saint John Regional Hospital; a nursing home; a fire station; the Irving refinery; schools; churches; and a number of residences.

95 Concerns were raised regarding the capabilities of first responders to attend to a high pressure natural gas pipeline emergency. The SJFD Risk Analysis Report identified deficiencies in the fire department's resources and capabilities and recommended a number of actions for EBPC to consider.

96 Intervenors submitted that details regarding first response to a pipeline emergency were either insufficient or impractical. Many intervenors sought information on how emergency response would be conducted: for instance, notification of residents, roles of first responders, and the possibility for evacuation. Intervenors were not satisfied that the means for notification were appropriate (e.g., knocking on doors, radio alerts), nor were they satisfied that the logistics were appropriately communicated to residents and businesses within the EPZ.

97 Secondary and emergency access was a topic of great concern to many participants, particularly to members of the communities of Milford and Randolph. Regarding Milford, it was the position of some intervenors that there was not a viable access route in the event of an emergency near the Lou Murphy overpass and that the agreement with J. D. Irving, Limited (J.D. Irving) to use Irving's road was not a viable alternative.

EBPC's Response to Concerns Raised

98 In response to concerns raised, EBPC described how the EPZ would be established after a risk assessment of the detailed pipeline routing was complete. EBPC maintained that the preferred corridor would provide flexibility for the final location of the pipeline and therefore the limits of the EPZ would be similarly flexible. EBPC does not expect that the Saint John Regional Hospital would fall within the EPZ. The Applicant cited numerous pipelines through urban corridors that pass in close proximity to facilities similar to those found in the City of Saint John, indicating that high pressure gas transmission pipelines are commonplace and can coexist within an urban setting.

99 EBPC responded to questions regarding the training and capabilities of first responders by assuring that training would be provided at EBPC's expense. Further, EBPC responded to the SJFD Risk Analysis Report by making commitments that addressed each of the recommendations, such as providing training and funding to first responders, consulting on the finalization of an ERP, and indicating there would be consideration of design alternatives. Details of the commitments were in EBPC's reply evidence.

100 In the event of a pipeline emergency, EBPC indicated that the Field ERP would be invoked. First responders and the EMO would notify homes and businesses by means of knocking on doors, mass broadcasts, and radio alerts. Any secondary fires or significant evacuation efforts would be handled by first responders and the EMO, including the selection and coordination of sheltering locations, incident command centers, and roadblocks. EBPC noted that public institutions typically require an evacuation plan and these plans would likely not require revision due to the presence of a natural gas pipeline. EBPC's role would be to advise first responders on the size of an appropriate evacuation zone, share relevant information that would be in the EPZ database, and to provide advice on when it would be safe for the public to return to their residences and businesses. EBPC committed to working with first responders and the EMO to adopt, promote, or help develop methods to notify the public and to identify areas with limited access and consider alternate routes. However, EBPC noted that primary responsibility in the event of a public emergency would lie with first responders.

101 Regarding secondary and emergency access, EBPC received assurance from J.D. Irving that access would be provided across its lands for emergency response vehicles and personnel should the existing access be impeded by a pipeline incident. EBPC confirmed that J.D. Irving personnel and equipment are on site 24 hours a day and could quickly open the gates for emergency access.

102 EBPC provided comments to the Board on a possible condition requiring that an emergency response exercise be conducted within six months after commencement of operation. According to EBPC, it discussed the draft conditions with first responders, and all parties agreed that an emergency response exercise should be conducted, but that it should be a table top exercise with the objectives of:

* verification of respective roles and responsibilities;
* verification of notification matrix; and,
* verification of practices and procedures.

Views of the Board

The views of the Board in the NEB EA Report under section 7.2.1 and 7.2.4.10 address many of the issues discussed above. To fully comply with the OPR-99 and meet the Board's expectations for an appropriate and effective EPRP, the Board expects EBPC's EPRP to include the following elements:

* emergency preparedness and response program development (hazard assessment);
* emergency procedures manual (EPM);
* liaison program (first responders);
* continuing education program (public);
* emergency response training;
* emergency response exercises;
* incident and response evaluation; and
* emergency response equipment.

Details on the expectations for each of these eight major expected elements can be found in Appendix B of the Guidance Notes for the OPR-99. The Board regularly conducts audits and inspections of companies' EPRPs for the purposes of verifying the presence of these elements and reviewing the appropriateness and effectiveness of each element.

As an initial step in this verification process, the Board generally places a condition on Certificates requiring the filing of the EPM within a predetermined timeframe prior to commencement of operation. This requirement enables the Board to review and resolve concerns with companies prior to operation. Should serious deficiencies in the EPM be identified and unresolved within that timeframe, the Board may withhold leave to open of the pipeline until such deficiencies are resolved. Due to the varying complexity and scope of pipeline applications before the Board, the EPM is often not available until immediately prior to operation.

Typically, the Board requires an applicant to submit its EPM 14 days prior to commencement of operation. In this instance, the level of public concern has warranted a greater timeframe for the Board to review the EPM. Should a Certificate be issued, the Board would impose a condition to requiring EBPC to file its EPM within 60 days prior to operation (condition 18 of Appendix V). In this case, 60 days would provide a timeframe within which there is flexibility to resolve outstanding concerns. Further, Board Emergency Management Specialists would be available to clarify the Board's expectations for submission of the EPM, and the Board encourages EBPC to consult with the Board's specialists at any time prior to submitting its EPM. The Board also reminds EBPC that an evacuation plan with potential evacuation points should be included in the EPM.

The Board recognizes that EBPC has M&NP's SJL EPRP upon which to base its EPRP for the proposed facilities. EBPC has demonstrated in this proceeding that the elements it is proposing to include in its EPRP are similar to those that the Board expects to find in an EPRP.

The training, resources, and capabilities of first responders were questioned throughout the proceeding. The Board notes EBPC's commitment to resolve concerns, such as to provide training and funding to first responders. The Board views EBPC's resolution of many of these concerns as a positive indication of stakeholder consultation; however, supporting evidence of consultation throughout the remaining development of the EPM will be required. Should a Certificate be issued, the Board will impose a condition to require filing of evidence of such consultation (condition 19 of Appendix V).

With respect to EBPC's comment on the Board's proposed condition to conduct an emergency response exercise, the Board refers parties to its view in the NEB EA Report on this matter. Should a Certificate be issued, the Board will require EBPC to conduct a full emergency response exercise as recommended in the NEB EA Report and as detailed in condition 21 of Appendix V. The Board expects that EBPC would identify critical locations, for example, where access and egress by first responders may be impeded, and would focus its exercise upon those locations. The Board is satisfied from the evidence that there is a reasonable access alternative available for first responders and the EMO, in the event of inaccessibility to the Lou Murphy overpass. However, due to the amount of public concern raised, the perceived lack of continuing public education, and the contested viability of secondary access, the Board strongly recommends that EBPC consider conducting the conditioned initial exercise near the community of Milford to evaluate the effectiveness of the EPRP as a whole.

To provide a baseline for verification of compliance with Board requirements and expectations regarding emergency response exercises, should a Certificate be issued, the Board will impose a condition for EBPC to file the proposed frequency and type of exercises and explain how results of such exercises would be integrated into the company's training and exercise program (condition 22 of Appendix V).

While EBPC cited a number of examples of high pressure natural gas transmission pipelines in an urban environment, the Board does not rely on precedence in making its decision. Successful operation of the Brunswick Pipeline under the Board's jurisdiction will be contingent, in part, upon adequate development and implementation of EBPC's EPRP.

Sections 53, 54 and 55 of OPR-99 require a company to conduct audits and inspections of its programs and systems to ensure that the pipeline is designed, constructed and operated safely and in compliance with regulatory requirements and conditions. The NEB routinely conducts audits and inspections of pipeline projects to verify regulatory compliance. These regulatory activities continue throughout the life of a project. The Board is of the view that the provisions of OPR-99 and the audit programs of the NEB, in conjunction with EBPC's commitments and fulfillment of the Certificate conditions referenced above, are sufficient to ensure that the Brunswick Pipeline will be operated in a safe manner.

Chapter 4

Supply and Markets

4.1 Justification for the Project

103 EBPC stated that the proposed Brunswick Pipeline would be required to support the Canaport[TM] LNG Terminal and that the Project would provide access to a significant and diverse new source of natural gas supply for markets in Maritime Canada and Northeast US. This regional addition to supply would be able to accommodate demand growth and would facilitate further development of Canadian markets and infrastructure. In fact, some of the gas Repsol would export to the US using the Brunswick Pipeline may be re-imported to Canada. Repsol's long-term development plans potentially provide for future natural gas service to Quebec markets.

Views of Interested Parties

104 Nova Scotia Department of Energy (NSDOE) felt that the justification and benefits in evidence for the Project were not clear for Canadian markets and argued that the Project would not promote the benefits of economic efficiency that potentially could be gained by more fully utilizing existing pipeline infrastructure in the Maritimes.

105 Enbridge Gas New Brunswick (EGNB) believed that the diversity of supply that this Project could bring to the market created the possibility of greater economic benefit to Maritime markets. This benefit is particularly attractive for EGNB's customers, both current and future, as its customers would have the possibility of receiving service through a direct interconnection between the Brunswick Pipeline and EGNB's distribution facilities. However, EGNB stated that it believed Canadian markets would not be well served by this Project if the benefits of the additional supply were never realized by those markets.

106 In the opinion of Bear Head LNG Corporation, Anadarko Canada LNG Marketing, Corp. and Anadarko LNG Marketing, LLC (Anadarko), the Brunswick Pipeline Project is a bypass pipeline designed to avoid the postage stamp toll on the Canadian M&NP system. Anadarko was of the view that the Project, if approved, would unnecessarily duplicate existing pipeline facilities that could be modified to accommodate the proposed new source of gas supply. Furthermore, Anadarko argued that the capital cost of expanding M&NP's Canadian facilities would likely be less than the cost of the proposed Brunswick Pipeline [See section 7.2 for further discussion of Anadarko's position].

107 In reply to Anadarko's argument, Repsol maintained that "greenfield" pipelines, like the proposed Brunswick Pipeline, that are needed to tie new sources of supply into the North American gas transmission grid do not duplicate any existing facilities. The Brunswick Pipeline would be a "greenfield" pipeline system connecting a new source of supply to the integrated North American gas transmission infrastructure.

108 Atlantica Centre for Energy, Inc. submitted that the Canaport[TM] LNG Terminal under construction on the east side of Saint John could provide the Maritime region with a new, long-term secure source of significant quantities of natural gas that would help build a strong local economy. However, in order for the Canaport[TM] LNG Terminal to be useful, it must be able to deliver the natural gas to markets. The party submitted that the Brunswick Pipeline would be a means of accomplishing this.

109 A number of interested parties believed that the Brunswick Pipeline would fulfill no specific need for the Maritime Region given that supply from existent projects could more than adequately meet the needs of Maritime Canada natural gas customers. Furthermore, some of these parties saw a potential for decreased reliance on fossil fuel energy, including natural gas, in exchange for greener and renewable resources in the future.

EBPC's Response to Concerns Raised

110 EBPC reiterated that through the use of the proposed Brunswick Pipeline, natural gas from the Canaport[TM] LNG Terminal would be made available to customers in Maritime Canada and other regions both to serve existing demand and to facilitate further development of the natural gas markets and infrastructure in those regions. EBPC stated that the Brunswick Pipeline would provide a potential direct connection to a new long-term source of supply for Canadian markets and, via exchanges, would also provide existing shippers and/or Maritime markets the ability to use M&NP transportation that might otherwise go unused. Shippers would not contract for future service on the M&NP system without gas supply.

Views of the Board

The Board is of the view that there will be a continued interest in the regional use of natural gas in the future and the Board accepts EBPC's evidence with respect to the need and justification for the Project proposed. On the basis of the evidence, the Board is persuaded that the intended purpose of the Brunswick Pipeline is to connect a new incremental supply source to existing markets and is of the view that the Project as proposed does not duplicate existing facilities in the region.

[See section 7.2 for further discussion of this issue].

While concern was expressed by some intervenors regarding potential future underutilization of regional pipeline infrastructure as a result of the introduction of the Brunswick Pipeline, the Board did not find reasonable grounds in the evidence to support this concern. To the contrary, the Board has been persuaded by the evidence before it that the implementation and subsequent operation of the proposed pipeline has the potential to encourage increased utilization of current energy infrastructure through the establishment of a new connection to a reliable incremental supply source, which could then be backhauled or otherwise transported through existing facilities. [See section 4.2.3 and Chapter 7 for further discussion of this matter.]

4.2 Gas Supply

4.2.1 Supply to the Project

111 EBPC submitted that the Brunswick Pipeline would interconnect with the Canaport[TM] LNG Terminal at Mispec Point in Saint John, NB. The Canaport[TM] LNG Terminal will be a facility capable of receiving LNG and regasifying up to 1,000,000 MMBtu/day of pipeline quality natural gas.

112 EBPC submitted that Repsol would be the owner of all of the natural gas output from the Canaport[TM] LNG Terminal. Accordingly, any gas supply transported through the Project would be provided by Repsol.

113 EBPC indicated that the Brunswick Pipeline would be able to transport, on a firm basis, 850,000 MMBtu/day. It would also be able to transport additional volumes of up to 150,000 MMBtu/day on an interruptible basis. These volumes would depend on system operating conditions, including operating pressure, and which customers would be taking service.

114 EBPC understood that Repsol plans to source the Canaport[TM] LNG Terminal's initial LNG supplies from Trinidad & Tobago. However, due to the logistical benefits that the Canaport[TM] LNG Terminal offers to most Atlantic Basin LNG supply projects, Repsol may acquire its LNG supplies from one or more of the other sources in the portfolio of Repsol YPF, Repsol's parent company, or even from third-party sponsored supply projects that could provide secure supply opportunities for Repsol. Repsol YPF is Spain's largest integrated oil company and one of the top ten private oil companies globally in terms of oil and natural gas production. Repsol assured the Board that the Repsol group of companies has sufficient LNG under contract to assure that the Canaport[TM] LNG Terminal and therefore the Brunswick Pipeline would be highly utilized.

115 The Applicant stated that the two LNG supply regions from which Eastern Canada may be expected to draw, the Atlantic Basin and the Middle East, represented 58 percent of world-wide capacity in 2005 and are likely to increase their share to 66 percent by 2010. According to EBPC, a substantial amount of new liquefaction capacity that could supply the Canaport[TM] LNG Terminal is scheduled for the Atlantic Basin.

Views of Interested Parties

116 NSDOE was of the view that there was no specific evidence in this proceeding regarding Repsol's portfolio strategy or how it manages its portfolio. NSDOE was not persuaded by the evidence that this Project, as proposed, would result in any incremental supply of gas to the Maritime markets. It was concerned that there were no actual commitments to a dedicated gas supply for the Brunswick Pipeline, only intentions.

117 EGNB expressed concern that there was a lack of specific commitments regarding the quantity of LNG, and therefore natural gas supply for the Brunswick Pipeline, to be delivered to the Canaport[TM] LNG Terminal. Because of this uncertainty surrounding the supply available to the Canaport[TM] LNG Terminal, EGNB was not persuaded that the facility would produce adequate natural gas supply for Repsol, the current sole shipper on the Brunswick Pipeline, nor was it persuaded that gas supplies not committed to Repsol would be available for Maritime markets.

118 Repsol stated that applications for Certificates for commercially at-risk pipelines do not need to be supported by existing gas supply or sales contracts. In its view, what was required of an applicant is evidence that would establish a reasonable expectation that a proposed pipeline project would operate at a reasonable level of utilization, that there would be sufficient gas supply available to the pipeline and that the gas would be able to find suitable markets.

EBPC's Response to Concerns Raised

119 Since Repsol would be paying all fixed charges on the Brunswick Pipeline regardless of throughput, according to the FSA, EBPC submitted that Repsol had incentive to maximize its use of the Brunswick Pipeline. Its use of the Brunswick Pipeline is dependent on ensuring that the Canaport[TM] LNG Terminal is receiving adequate LNG supplies from Repsol's portfolio.

120 EBPC argued that the portfolio of LNG available to Repsol for use at the Canaport[TM] LNG Terminal would be as secure as the portfolio of LNG supply that the Repsol group of companies utilizes for all of its interests in LNG terminals worldwide. Projects in Eastern Canada would compete for supply with other North American locations. EBPC submitted that the Maritimes enjoys a significant transportation advantage over existing US terminals for many supplying locations since the transportation distances to terminals in the Maritimes would be shorter.

121 EBPC submitted that LNG terminals in the Maritimes have the best transportation advantage over terminals in the Gulf Coast with respect to supplies from Northern Europe, followed by supplies from North Africa and the Middle East. West Africa would provide a somewhat smaller advantage, but there would be basically no advantage for Caribbean supplies. Thus, in EBPC's view, the best alternatives for Maritime projects would be to seek supplies from Northern Europe, North Africa or the Middle East.

Views of the Board

The Board finds that sufficient evidence was presented to satisfy the Board regarding the capacity and ability of the Canaport[TM] LNG Terminal to deliver a sufficient volume of natural gas to support the applied-for facilities. The Board is persuaded that LNG would provide a unique source of supply for any given project, and its ability to support a downstream project, such as the applied-for facilities, may be viewed differently from supply from a dedicated gas field. The Board finds that there are both positives and negatives associated with relying on a portfolio of assets. While a portfolio of assets may not provide a specific dedicated supply field to a project, there is the flexibility to draw from various fields and therefore mitigate potential supply problems in any given supply basin. The Board finds that, in this instance, rather than relying on the ability of one supply basin to fulfill the long-term needs of the Project, the Brunswick Pipeline would be able to rely, indirectly, on multiple supply basins. Based on the evidence submitted, the Board is of the view that the gas suppliers in this case will be able to satisfy Brunswick Pipeline's natural gas supply needs. Therefore, the Board concludes that there is sufficient certainty that the Canaport[TM] LNG Terminal will be able to rely on LNG supply from Repsol's portfolio of upstream assets to reasonably satisfy the supply requirements of the Brunswick Pipeline Project.

4.2.2 Regional State of Supply

122 EBPC is seeking approval of a pipeline that would potentially connect a new incremental supply source to natural gas markets in Maritime Canada. EBPC submitted that in a recent NEB report, The Maritimes Natural Gas Market: An Overview and Assessment, 2003, the Board stated: "[l]ooking to the future, the most important issue is the uncertainty surrounding the timing of the development of additional supply". EBPC pointed out that the Maritime Canada natural gas market is currently being served by Sable Offshore Energy Project (SOEP), and the current outlook for additional significant deliverability in the Maritime Region is uncertain.

Views of Interested Parties

123 Repsol submitted that Sable gas supplies were declining at a faster rate than originally expected as demonstrated by:

a) evidence indicating that Sable gas supplies could reach non-economic production levels between three and six years;

b) the actions of Sable producers in turning back most of their transportation obligations on the M&NP US pipeline system (on the condition that the Brunswick Pipeline would be approved); and

c) the absence of evidence from any other intervenors indicating otherwise.

124 Irving Oil Limited (Irving Oil) indicated that there was no longer any assurance that the long-term supply needs of SOEP customers, including Irving Oil, could be met. Irving Oil was of the view that, as both the largest single user (80 percent) of natural gas in Maritime Canada and as an existing shipper on M&NP having significant demand charge commitments on the M&NP system, it has justifiable concerns with respect to its long-term potential natural gas supplies.

125 NSDOE indicated that it was not persuaded by the evidence that the proposed Project is the only or the best alternative for meeting the supply needs of the Maritimes. NSDOE and others maintained that there are other options including Deep Panuke, Corridor Resources, other potential LNG projects, and backhaul of US supply via a reversed M&NP pipeline system, that could bring a much needed additional supply of natural gas to markets in Maritime Canada.

126 Anadarko emphasized that, in its opinion, LNG suppliers are seeking the most attractively priced and liquid markets. The Northeast US markets are a natural anchor for Eastern Canadian coastal LNG terminal projects, and the Brunswick Pipeline has been presented as a much cheaper transportation alternative than the only other option available for transporting supply from Maritime Canada to the downstream anchor market, M&NP. In Anadarko's view, the difficulties that Bearhead LNG had experienced in obtaining upstream LNG supply had been exacerbated by the competing Canaport[TM] LNG Terminal's potential access to much lower Canadian transportation costs on the Brunswick Pipeline. [See section 7.2 for further discussion of this matter.]

127 Other intervenors were not persuaded by the evidence that natural gas would be as much of a fuel of choice in the future. In their view, other fuel alternatives may become increasingly feasible and attractive to the Maritimes, and this could offset some of the forecasted incremental demand growth. Intervenors stated that an interest in alternative fuels could thus reduce the need for additional regional natural gas supply sources and subsequently the need for transportation of that natural gas.

EBPC's Response to Concerns Raised

128 EBPC reiterated that the project before the Board at this time is the proposed Brunswick Pipeline Project, and that it would not be appropriate to compare this Project to hypothetical alternatives, such as other LNG projects or alternative resources, options that may or may not be feasible at a future date. In its view, incremental natural gas supplies could be used to expand the current Maritime Canada market and also supplement the current SOEP supplies, thereby ensuring adequate long-term supplies to continue the long-term operations of existing and potential future industrial users of natural gas in the Maritime Canada market.

Views of the Board

> The Board is of the view that additional supply to the Maritimes is a necessary component for Maritime Canada's future natural gas market development. Little evidence was submitted to show that alternative fuel options would significantly reduce this need. The need for new regional supply was addressed by various parties involved in the proceeding, as noted above, and the Board finds from the evidence that an incremental regional natural gas supply source is necessary for Maritime Canada to promote the long-term growth of the regional energy market.

4.2.3 Maritime Canada Access to Supply

129 EBPC stated that the gas delivered through the Brunswick Pipeline would be accessible to Maritime markets by a number of means including the following:

1. When gas is flowing on M&NP to the US:

    a) Repsol and shippers on M&NP could enter into an exchange transaction, also called a swap, whereby supplies of natural gas transported on the Brunswick Pipeline would be delivered to a US customer of an M&NP shipper while that M&NP shipper serves the needs of an Irving Oil/Repsol customer in Canada by delivering gas to the Canadian customer on the M&NP pipeline; or

    b) an existing or new shipper on M&NP could elect to receive natural gas using St. Stephen as its receipt point.

2. When gas is not flowing on M&NP to the US, natural gas could be physically backhauled on M&NP from the Canada/US border. Thus an existing M&NP shipper could use St. Stephen as a secondary receipt point or a new M&NP shipper could contract for capacity on M&NP to receive gas at St. Stephen for delivery along M&NP. The M&NP system has been designed to accommodate reverse flows or physical backhauls.
3. A direct pipeline connection to the Brunswick Pipeline could be made.

130 Accordingly, EBPC submitted that any party currently connected to M&NP could contract for natural gas supplies from the Canaport[TM] LNG Terminal and receive the supplies via a swap, a change in its receipt point, a direct connection to the Brunswick Pipeline, a backhaul, or any combination of such.

131 EBPC indicated that the potential combined firm and interruptible capacity on the Brunswick Pipeline would exceed the capacity reserved by Repsol's affiliate on M&NP US (approximately 750,000 MMBtu/day including fuel). EBPC submitted that, even if Repsol's affiliate were fully utilizing its reserved capacity on M&NP US, up to 250,000 MMBtu/day of incremental capacity on the Brunswick Pipeline would be available to provide deliveries of natural gas from the Canaport[TM] LNG Terminal to the Maritime Canada market.

132 EBPC submitted that the amount of gas available for Maritime Canada markets would depend primarily on four things: (a) the capacity of the Canaport[TM] LNG Terminal, (b) the capacity of the Brunswick Pipeline, (c) the size of the market in Maritime Canada, and (d) the ability of buyers and sellers to reach mutually satisfactory commercial terms for the sale and purchase of natural gas.

Views of Interested Parties

133 EGNB was not persuaded that having natural gas available to Maritime Canada markets via EBPC's proposed methods of backhauls or swaps would provide Maritime markets with adequate assurance of secure access to supply. EGNB argued that backhauls and swaps could result in unnecessary costs to natural gas customers that could be avoided with a direct connection. Further, EGNB believed that the Applicant's proposed methods of access could be detrimentally affected by unrelated upstream activity. EGNB stated that swapping would only be possible if a willing party had supplies available to swap. Given decreasing deliveries from SOEP and uncertainty around additional regional developments, this method may prove to be impossible for M&NP shippers. For backhauls, a similar challenge could exist as some of the projects being planned to utilize a backhaul service may not exist. EGNB therefore submitted that these methods of access to gas for Maritime markets would not be optimal for the Canadian public interest. EGNB requested that the Board add a condition to any Certificate it might issue for the Project that would provide for third party access to the pipeline.

134 EGNB submitted that even if direct access to the Brunswick Pipeline could be guaranteed, this would not provide the necessary assurance for the distribution company regarding its ability to access supplies from this new incremental natural gas source, and that source of supply was a large component of EBPC's justification for its proposed Brunswick Pipeline. EGNB recommended that a condition be placed on the Applicant's applied-for Certificate that would reserve a portion of the incremental natural gas supply for the Maritimes.

135 Evidence indicated that negotiations between Irving Oil and Repsol are ongoing; however, NSDOE stated that no gas had been set aside for Maritime Canada markets, and none would be unless somebody was able to negotiate acceptable terms with Repsol.

136 Irving Oil stated that, while Repsol and Irving Oil have not yet completed the negotiation of commercial agreements such that Irving Oil could pursue marketing the Canaport[TM] LNG Terminal natural gas, they had initiated discussions on the necessary arrangements. Under these arrangements, Irving Oil would purchase natural gas from the Canaport[TM] LNG Terminal, both for its proprietary use and for resale to third parties in Maritime Canada, pursuant to its marketing rights. Irving Oil stated that it intends to utilize, for its local proprietary purposes, roughly one-third or about 80,000 MMBtu/day of the natural gas that could be available, leaving approximately 170,000 MMBtu/day that it intended to market to third parties in the rest of Maritime Canada.

137 Repsol confirmed that an initial framework of commercial arrangements governing the marketing of Canaport[TM] LNG Terminal natural gas was in place, and this framework would help the finalization of negotiations between Repsol and Irving Oil. Irving Oil would be the exclusive marketer of Canaport[TM] LNG Terminal natural gas in Maritime Canada, and up to 250,000 MMBtu/day of natural gas (firm and interruptible) would be available through Repsol's exclusive marketer, Irving Oil, for Canadian shippers to acquire the gas on competitive terms and conditions.

EBPC's Response to Concerns Raised

138 EBPC maintained that Maritime Canada interests would be adequately satisfied by the proposed Brunswick Pipeline. Based on the information contained in M&NP's 2005 annual surveillance report filed with the Board, 410,000 MMBtu/day of gas was transported by M&NP during the 12 months ending 31 December 2005. The report further indicated that deliveries to Maritime Canada markets were only 19 percent of total gas transported, or about 80,000 MMBtu/day. Accordingly, the potential 250,000 MMBtu/day of gas that could be made available on the Brunswick Pipeline to Maritime Canada markets would be over three times the average daily quantities that had been delivered to Maritime Canada markets in 2005. Therefore, EBPC argued that the available capacity on its proposed pipeline could provide ample deliveries to the existing Maritime Canada market as well as to new markets that might develop there.

139 Although negotiations have yet been completed, EBPC submitted that Repsol would like to see its sales quantities reach 1,000,000 MMBtu/day as close to the start-up of the Canaport[TM] LNG Terminal as possible. It argued that this provided a strong motivation for Repsol to maximize sales to the Maritime Canadian market. In addition to this, up to 250,000 MMBtu/day of Canaport[TM] LNG Terminal natural gas could be sold in Maritime Canada without Repsol incurring any incremental pipeline transportation costs. Accordingly, EBPC submitted that Repsol has a very strong incentive to negotiate an agreement with Irving Oil, its exclusive marketing agent in Maritime Canada, so that it could sell up to 250,000 MMBtu/day of Canaport[TM] LNG Terminal natural gas in the Maritimes.

140 In order to satisfy concerns expressed by intervenors regarding direct access to the Brunswick Pipeline, EBPC has stated that it would be open to, and would make the necessary arrangements for, any third-party interested in attaining direct access to its Pipeline through the construction of third-party sponsored connections. [See section 7.1 for further discussion of access matters.]

Views of the Board

As previously found, the Board is of the view that one aspect for the justification of this Project is its ability to provide an opportunity for access to a new source of natural gas supply to the Maritimes. While some parties expressed concerns regarding the ability of Maritime Canada markets to access the incremental gas supply provided by the Project, the evidence before the Board indicates that Irving Oil is the largest user of natural gas in Maritime Canada. Therefore, Irving Oil's access to the gas supply supports the Board's finding that there will be Canadian access to the Project's gas supply. Furthermore, Maritime Canada could also access this new natural gas supply source, to fulfill current and anticipated future natural gas needs, through the use of backhauls, swaps and direct connection to the Brunswick Pipeline.

> Based on the record in this proceeding, including the current and anticipated use of natural gas, the Board is of the view that it is reasonable to conclude that the current and anticipated needs of Maritime Canada's market would be adequately met. [See section 7.2 for further discussion.] This Project would make new natural gas supplies accessible to the market, and the Board is of the view that market forces would adequately govern the distribution of natural gas within the Maritimes and the Northeast US. Based on the evidence noted above, the Board is not persuaded that imposing a condition, such as the one proposed by EGNB to reserve a certain amount of natural gas for a specific region in an open market, is necessary.

4.3 Markets and Need for the Proposed Pipeline

4.3.1 Demand for Gas

141 Concentric Energy Advisors (CE Advisors), retained by EBPC to conduct a study of demand for natural gas, projected significant incremental design day demand growth across Atlantic Canada and much of the Northeast US, in both the local distribution company (LDC) and power generation segments of the market. Specifically, by 2010, the incremental design day demand requirement was projected to be 1,311,000 MMBtu/day, of which 58 percent or 765,000 MMBtu/day is LDC driven, and 42 percent or 546,000 MMBtu/day is due to gas-fired generation requirements. By 2030, the incremental gas requirement was forecast to be 7,621,000 MMBtu/day, with LDC and gas-fired generation segments each representing approximately 50 percent of the projected demand.

142 CE Advisors indicated that, for Atlantic Canada, natural gas demand from the electric generation segment could increase significantly as a result of the introduction of a new gas supply source, such as the supply from the Canaport[TM] LNG Terminal, and this would diversify the natural gas supplies in Atlantic Canada. In addition, climate change initiatives are favourable for natural gas, since natural gas is the cleanest burning fuel of the coal, oil, and natural gas options. Therefore, a long-term regional supply of this commodity could support an increased interest in gas-fired power generation in the future.

143 According to CE Advisors, the increased demand for natural gas in Atlantic Canada and Northeast US would likely be met through an increase in LNG imports. CE Advisors stated that it expects that LNG would supply approximately 16 percent of the US gas requirements by 2030, which is a significant increase over 2005 when LNG met only 3 percent of the US natural gas demand.

Views of Interested Parties

144 Irving Oil submitted that it would continue to honour its contractual commitments on the M&NP system, including its commitments on the SJL. Irving Oil maintains that it has interests in this Project as an indirect holder of a 25 percent interest in the Canaport[TM] LNG Terminal; as a buyer of Sable supply concerned about future supply security; as an existing shipper on M&NP, which like others recognizes the opportunities that the Brunswick Pipeline would provide for transactions on that system; and as a significant user of natural gas in Maritime Canada that believes strongly in the opportunities to further develop the market and its underlying infrastructure.

145 Some intervenors argued that there was no evidence on the record to indicate whether Irving Oil intends to receive this supply directly at the Canaport[TM] LNG Terminal or via the proposed Brunswick Pipeline. Therefore, the benefits to Maritime Canada of adding an incremental supply source to the Maritime Region could be satisfied without the proposed Project. In questioning CE Advisors, intervenors raised a concern that the incremental supply source would be used to fill a need in the Northeast US and not a need in Atlantic Canada. An issue was also raised about whether current SOEP production would be able to adequately fulfill current Maritime regional natural gas demand.

EBPC's Response to Concerns Raised

146 In EBPC's view, existing and potential customers need and must secure long-term natural gas supply in order to engage and commit to growing markets. Without a long-term supply, these markets could not grow, and the opportunities and related benefits would be missed.

147 EBPC submitted that the proposed Project provides the necessary connection of a new natural gas supply source to the mature anchor market of the Northeast US and to the still relatively immature but potential growth markets of the Maritime region. The testimony of Mr. Reed for CE Advisors suggested that, at present, the supply and demand for natural gas in the Maritimes was in balance, but the situation was one where demand had been very much constrained by the lack of secure long-term supplies to the Maritimes. Assuming that the Maritimes continued to rely primarily on SOEP supplies, CE Advisor's projections are that within the next five years, a level of deliverability from SOEP would be reached that would limit SOEP's commercial practicability in terms of continuing to flow gas on a significant basis.

> ***Views of the Board***
>
> The Board is of the view that it is reasonable to conclude from the evidence that both maintenance of existing levels of demand for natural gas and potential growth in natural gas demand within the Maritimes could be satisfied through the introduction of a new natural gas supply source. Further, the Board is of the view that increased use of natural gas over other fuels, such as coal and oil, could provide potential benefits to the Maritimes.
>
> While there is the possibility that a portion of the Maritime Canada demand for the Canaport[TM] LNG Terminal natural gas could be satisfied without using the applied-for pipeline facilities, the Board is of the view that Maritime Canada demand alone is not currently substantial enough to attract the necessary investment in LNG infrastructure to bring a new source of natural gas supply to the Maritimes and Northeast US. Based on the evidence on the record, the Board finds it reasonable to conclude that a project providing the means of transporting natural gas to an an-

chor market is integral to the viability of that project providing access to a new natural gas supply source. The Board is persuaded that the Northeast US provides such an anchor market for the natural gas from this Project, and therefore the demand for gas in the Northeast US ultimately underpins the investment required in bringing incremental supplies to the Maritimes and Northeast US.

Furthermore, the Board notes that there are a number of methods that may be used to allow the Maritimes to access this gas through the use of the Brunswick Pipeline, including through direct connection, swaps and backhauls. Therefore, the Board is of the view that the Brunswick

Pipeline provides the means for this incremental source of gas supply to provide a benefit to energy consumers in the Maritimes.

4.3.2 Price of Natural Gas

148 EBPC submitted that a challenge to market growth in the Maritimes has been the dramatic increase in the price of gas since it became available to markets in the Maritimes. The price of natural gas in the Northeast US was in the order of $2/MMBtu in October of 2001, but has been as high as $15/MMBtu in October of 2005 and averaged $10/MMBtu in 2005. The Applicant stated that increased natural gas supply in the Maritimes and Northeast US could assist in stabilizing Maritime pricing and thereby could facilitate market penetration.

Views of Interested Parties

149 Repsol stated that adding a new source of supply could potentially result in lower prices and facilitate the development of additional natural gas markets in Canada.

150 NSDOE submitted that there are certain features of the Brunswick Pipeline Project that make it doubtful that transparency and price discovery would be improved. For instance, there would be a sole shipper and an exclusive marketer, and if Maritime Canada markets were to acquire benefits from the gas supplied by the Brunswick Pipeline, it would likely be through secondary market transactions that would not be transparent.

EBPC's Response to Concerns Raised

151 EBPC suggested that the reduced transportation charges to SOEP producers on M&NP US that would be enabled by the gas supply from the Brunswick Pipeline, and the potential for lower transportation tolls to be obtained through the secondary market on M&NP, could hypothetically lead to lower prices in the Maritimes than in the Northeast US.

Views of the Board

The Board appreciates the concerns about price transparency and price discovery expressed by some parties; however, the Board is of the view that open and competitive markets within the Maritimes will be encouraged through the increased development of competitive regional markets for natural gas. In the Board's view, the introduction of an incremental source of natural gas supply to the Maritimes and the Northeast US could alleviate some of the supply/demand pressure in the Northeast US anchor market, which in turn could decrease potential short-term price volatility and facilitate long-term price stability for the region. The stabilization of prices could subsequently help facilitate the growth of the natural gas market in the Maritimes. These benefits provide an opportunity for the markets to work more efficiently, which is a benefit to Canadians in and of itself and is part of the NEB's stated Goal 3.[22]

4.4 Competition

Views of Interested Parties

152 Several intervenors expressed the concern that Irving Oil's exclusive marketing arrangement to market natural gas from the Project in the Maritimes may impede competition, EGNB's franchise rights, and the realization of overall benefits.

153 One intervenor suggested that incremental supply enhances supply diversity and would enhance gas commodity competitiveness rather than impede it.

154 Irving Oil stated that it intended to work closely with both EGNB and Heritage Gas to ensure that benefits from this new and diverse supply of natural gas would be available in the Maritimes.

EBPC's Response to Concerns Raised

155 EBPC stated that the natural gas market is a competitive market. Competitive constraints from SOEP, Corridor Resources and other supplies in the US would prevent the Irving/Repsol partnership from impeding trade.

156 EBPC submitted that there is no evidence that the proposed marketing arrangement between Repsol and Irving Oil would impair the competitiveness of gas commodity transactions in the Maritimes.

Views of the Board

The Board is of the view that it is not likely that competition within the Maritimes and the Northeast US will be impeded through the implementation and subsequent operation of the proposed pipeline. The Project would introduce a new source of natural gas supply to the Maritimes, and this added source of supply could act as an impetus, not an impediment, for competition. Furthermore, the Board is not persuaded on the evidence submitted that the arrangements surrounding Irving Oil's position as sole marketer within the Maritimes would create a non-open or non-competitive market environment within the Maritimes. Should parties have a concern that anti-competitive behaviour is occurring, the Board notes that there are complaint and investigative processes available to address this type of behaviour under the *Competition Act* (R.S.C. 1985, c. C-34).

Chapter 5

Consultation

157 The expectations for an applicant regarding consultation are set out in section 3.3 of the Board's Filing Manual. The Board expects that applicants would consult with affected parties for all projects. Applicants are responsible for justifying the extent of consultation carried out for each application. The Board also expects that a consultation program will continue throughout the regulatory process, as well as during the construction and operation phases of a project. The following information should be provided within an application:

* principles and goals of the consultation program;
* design details of the consultation program; and
* the outcome of implementation of the consultation program, including how public input influenced the design, construction, or operation of the project.

158 As part of its overall assessment of a proposed project, the Board also considers land matters related to route selection, the lands required for the project, and the land acquisition process. For additional details regarding the consultation associated with land matters, refer to section 6.3.

5.1 Public Consultation Program

159 EBPC's predecessor in the Project, M&NP, and its consultants, designed and implemented a consultation program for the Project targeted at various potential stakeholders, including the general public, landowners, government and municipal agencies, Aboriginal peoples, other interest groups and associations. EBPC adopted and committed to the consultation program initially established by M&NP.

160 In its application, EBPC stated that the purpose of the consultation program was to:

* provide sufficient information to stakeholders about the Project in a timely manner;
* provide stakeholders an opportunity to have meaningful input into decisions with respect to project planning and development;
* obtain environmental and socio-economic information from those stakeholders most familiar with the Project area to enable the identification of constraints, which may affect project location or mitigation measures;
* identify issues and concerns of those stakeholders potentially affected by the Project; and
* establish communication with stakeholders to facilitate issue resolution and ongoing communication as the Project moves through the planning, construction and post-construction phases.

161 EBPC stated that the following consultation activities had been undertaken for the Project:

* In mid-August 2005, M&NP placed a Project announcement in provincial and local newspapers to provide early public notification of the Project.
* Open house sessions were held on September 20, 21 and 22, 2005 in Saint John, St. Stephen and Pennfield, NB respectively. The open houses served to introduce the Project and provide information to the general public on such items as the EA process, potential pipeline corridors, a description of the pipeline construction process, the Project regulatory and approvals process, lands-related information and other Project details.
* An additional open house was held in Saint John on December 6, 2005 to present information on the Project and to introduce potential pipeline corridor variants that would largely avoid Rockwood Park.
* A variety of techniques were used to provide information to the public and to elicit feedback about the Project, including: questionnaires; newspaper advertisements; radio spots; 1-800 phone number; email address; project website; newsletters, including a corridor map delivered to every mailing address in Saint John and the communities along the proposed corridor; site visits; one-on-one and group meetings; and establishing a Lands office in the City of Saint John.
* Contacts were made with individual landowners (717 open files as of November 2006).
* During the summer of 2006, three community meetings and walk-arounds were held (Milford, Millidgeville and Champlain Heights) at the request of the general public and their elected leaders.

162 The geographic region included in the public consultation program covered the area between the Canaport[TM] LNG Terminal on Mispec Point in Saint John, NB and the international border near St. Stephen, NB. EBPC submitted that stakeholder groups with an interest in the Project had been identified within that area. Communities within 10 km of the preliminary preferred corridor were solicited to participate in the open houses and public consultation program for the Project. EBPC stated that it attempted to ensure that all potential stakeholders located within the corridor, including directly affected landowners, were contacted directly, while potential stakeholders located beyond the corridor would receive general public notification through open houses, mailings and other commonly-used means of notification.

Views of Interested Parties

163 Several participants submitted that the consultation program implemented by EBPC was inadequate. The focus of the submissions related primarily to the public consultation process and, in particular, to the timing of consultation, the quality and responsiveness of the consultation program, and the ability of stakeholders to have meaningful input into decisions regarding project planning and development. The following paragraphs highlight some of the issues and concerns that were raised during the hearing process.

164 FORP claimed that EBPC had not fulfilled the goals of its consultation program nor had it fulfilled the regulatory requirements for consultation. There was no possibility for EBPC to gather "feedback from affected parties in the design and planning" because EBPC had presented a completed plan at its first open house. EBPC did not provide "sufficient information to stakeholders about the Project in a timely manner." Further, FORP submitted that EBPC's lack of engagement with the main stakeholder, the community of Saint John, indicated its lack of concern for that community. FORP also argued that EBPC had not reviewed safety issues with the SJFD Chief, the EMO or medical experts prior to choosing the preferred pipeline route.

165 One intervenor claimed that the EBPC and M&NP land agents had been evasive, deceitful, and unprofessional.

166 Another intervenor submitted that little weight should be accorded to EBPC's success in gaining the support of the co-stewards of Rockwood Park (i.e., the Saint John Horticultural Association and the City of Saint John) for the following reasons:

* both referenced groups had chosen to ignore their responsibility to protect Rockwood Park from being subjected to these kinds of uses;
* Saint John City Council had twice voted unanimously in favour of the marine route;
* no input from the public, whose park it is, was sought by Council before its abrupt change of conviction and acceptance of an easement through Rockwood Park that lasts until the end of time;
* over fifteen thousand petitioners expressed opposition to a pipeline through their City and their Park; and
* the support of those two groups was only obtained just days before the Oral Hearing began when the "inducement of some $5.3 million dollars, contingent upon NEB approval of the application for a route through the Park, resulted in the abandonment of all regard for ... recent motions passed, their commitment to intervene on behalf of citizens, and overwhelming public sentiment."

167 One letter of comment writer stated that when speaking with the company, EBPC did not mention the HDD noise, the period of time it would take, the noise levels people would be expected to tolerate, or that the HDD would be going on for 24 hours a day. The exit point for the proposed HDD would be approximately 94 m from the writer's home. The writer claimed that it appeared that the company's representatives had not told the residents all of the facts.

EBPC's Response to Concerns Raised

168 EBPC defended its consultation process by stating that it had worked very diligently to reach out to the public and a number of project stakeholders. EBPC submitted that it would continue to work in partnership with the community of Saint John and was very pleased with the progress made to date.

169 EBPC rejected the suggestion that its consultation activities had been inadequate. While some of the intervenors may not agree with the outcome, EBPC argued that the development of this Project featured an open, interactive consultation process that resulted in changes to the proposed corridors, the introduction of specialized construction techniques and the dissemination of considerable information about the construction and operation of pipelines in both urban and rural environments.

170 EBPC considered feedback from stakeholders and amended its application to reflect minor amendments to the preferred corridor. EBPC remains committed to its ongoing consultation program. Should it become apparent that its proposals could be improved, EBPC would be prepared, in an open and cooperative manner, to make the appropriate changes, subject to the Board's approval.

171 EBPC secured the support of critical intervenors, such as existing shippers on the M&NP system (Heritage Gas Limited, EGNB, Nova Scotia Power Incorporated), New Brunswick Power Transmission Corporation (NB Power), the Saint John Horticultural Association, the City of Saint John, the Union of New Brunswick Indians (UNBI),[23] and the MAWIW Council.[24] EBPC has also acquired support for its proposed routing from most owners along the RoW that the pipeline would share from the Saint John city limits to the international border at the St. Croix River.

172 Further, as a direct result of the consultation and EBPC's undertakings, the City (with direct municipal responsibility for Rockwood Park) and the Horticultural Society (with stewardship over Rockwood Park) now support the Project and the preferred route.

173 EBPC argued that it was doubtful that those who were asked to sign a petition over an extended period of months had been provided with the same information or possessed the same expertise as the Fire Chief or other municipal officials, particularly where they purported to object on the basis of impacts to such things as municipal infrastructure. In EBPC's view, the process had worked as it was supposed to: contact was made; consultations took place; information gaps were filled; uncertainties clarified; and commitments were made to allay initial concerns.

174 Regarding the FORP argument that EBPC did not review safety issues with the SJFD Chief, EMO or medical experts prior to choosing the preferred pipeline route, EBPC stated that the record was quite clear that the pipeline route itself had not yet been chosen, as the detailed routing process was ongoing. However, in discussing public safety related to the preferred corridor with the SJFD Chief, EBPC submitted that it had addressed all of the recommendations that were made in the SJFD Risk Analysis report.

175 EBPC stated that the public had not been notified of the Project until there was a project. A precedent agreement was signed between M&NP and Repsol in July 2005. Immediately after the signing, a notice of intent to prepare an EA was placed in local French and English newspapers followed by newspaper ads, radio spots and flyers distributed regarding the September open houses.

176 Regarding the timing of the announcement of the financial endowment, EBPC stated that it had been involved in discussions with the City and the Horticultural Society for some time about how EBPC could make a contribution to the community, as well as address other issues. EBPC worked with the City to resolve those other issues and made a number of commitments to City Council concerning those issues. That process lasted until late October after which EBPC made the offer of the endowment.

177 EBPC submitted that it did listen, and did hear what the general public had been saying. The balance of information from all sources led to the selection of the preferred corridor. The fact that EBPC did not act on the wishes of any particular intervenor in no way suggested those intervenors' concerns were not heard or taken into consideration.

5.2 Aboriginal Consultation

178 EBPC stated that an Aboriginal consultation process was initiated in July 2005 in order to inform the First Nation communities of the Project objectives, timelines, routing, regulatory processes, and proposed construction activities. This process was designed to be consistent with the basic principles of EBPC's Aboriginal consultation program and with NEB filing requirements. The Aboriginal consultation principles, listed below, describe EBPC's framework for interaction with First Nations:

* early in the planning phase of the Project, identify Aboriginal communities with traditional interests in the Project area that could potentially be affected by the Project;
* inform potentially affected Aboriginal communities throughout the various phases of the Project by sharing information on key Project specifics in a clear and timely manner;
* create opportunities for meaningful input and advise the communities of opportunities to communicate with the NEB;
* understand and respond to any issues or concerns in an effort to ensure those issues or concerns are resolved or mitigated; and
* continue ongoing communications with the Aboriginal communities throughout the construction and post-construction phases with a view to maintaining and developing long-term relationships required for the operation of the facilities.

179 EBPC stated that it had applied and would continue to apply these principles and initiatives throughout the consultation process, the ensuing construction period, as well as into ongoing operations.

180 The Aboriginal strategy identified for the Brunswick Pipeline included:

* hiring an Aboriginal Relations Manager;
* funding for two Aboriginal community liaisons;
* meetings with the First Nation leadership (Chief and Council);
* meetings with Aboriginal organizations;
* open houses in First Nation communities; and
* funding to conduct a Traditional Ecological Knowledge (TEK) Study.

Views of Interested Parties

181 On 20 October 2006, the MAWIW Council of First Nations filed a letter indicating that, with the conclusion of twin agreements with M&NP and EBPC, the MAWIW Council supported the Brunswick Pipeline application.

182 On 26 October 2006, UNBI filed a letter stating it was withdrawing as an intervenor in the NEB hearings because it had reached a benefits agreement with EBPC. UNBI also withdrew its evidence and information requests.

183 One intervenor argued that EBPC had not consulted with the Passamaquoddy First Nations Peoples of NB. Therefore, no agreement existed between EBPC and the Passamaquoddy First Nation.

184 One oral statement provider stated concern that the Project would be located within Passamaquoddy territory, and yet the Passamaquoddy people had not been properly consulted. The oral statement provider went on to claim that the Passamaquoddy Chief spoke about people currently using plants harvested in and around the pipeline corridor for food and medicine.

EBPC's Response to Concerns Raised

185 In the early stages of the Project, the Applicant engaged in Aboriginal consultations directed at securing Aboriginal support for and involvement in various project activities. Careful attention was also paid to mitigating impacts upon traditional uses along the pipeline route. EBPC stated that the process had been open and inclusive. Those consultations resulted in agreements with the Province's two Aboriginal organizations, UNBI and the MAWIW Council, both of which had indicated their support for the timely approval of the Project.

186 The agreements include provisions for environmental monitoring and protection of Aboriginal heritage and cultural resources. They also encourage capacity building within First Nations through training, scholarships, and organizational development funding. Aboriginal inclusion commitments made by EBPC would lead to contracting opportunities for First Nation businesses. The agreements also contain provisions for the continued engagement of liaison staff, oversight committees, and ongoing meaningful dialogue.

187 EBPC committed to establishing a process through which any issues, including those that may be raised by the Passamaquoddy, could be communicated and considered by EBPC through its Aboriginal Manager. Further details about EBPC's evidence on this matter are summarized in the NEB's EA Report, at section 7.2.4.9.

Views of the Board

The NEB promotes the undertaking, by regulated companies, of an appropriate level of public involvement, commensurate with the setting, and the nature and magnitude of each project. This recognizes that public involvement is a fundamental component during each phase in the lifecycle of a project (i.e., project design, construction, operation and maintenance, and abandonment) in order to address potential impacts. The Board expects companies to pursue approaches that strengthen democratic processes and build the social and human capital of local communities.

Regarding the design of a project-specific consultation program, the Board expects an applicant to indicate why the design of its consultation program was appropriate for the nature and magnitude of the project. There were several examples illustrating how the design of EBPC's consultation program was appropriate, including: the consultation program was initiated early in the process; modifications were made to the Project in response to concerns raised; agreements of support were reached with key stakeholders; multiple techniques were used to inform the public about the Project; and commitments were made by EBPC to continue consultation efforts as the Project moves through the planning, construction and operations phases.

However, there were also several examples highlighting how certain areas could have been improved, including: the perception of incomplete notification of landowners around the proposed HDD sites; allegations concerning the unprofessional behaviour of some of EBPC's land agents; the negative public perception associated with EBPC's approach to secure support from the City of Saint John; and failure to identify whether the Passamaquoddy First Nation was a potentially affected party. The Board notes that EBPC adopted the consultation plan and protocol established by M&NP, so both companies share some responsibility for the areas that could have been improved. EBPC is the company accountable for the ongoing consultation program, and therefore the Board notes that EBPC has the responsibility of ensuring the success of the ongoing consultation program.

Regarding the implementation of a consultation program, the NEB expects an applicant to include a description of the outcomes of the public consultation program conducted for the project. EBPC filed such a description for the Project. Members of the public were also given an opportunity to communicate directly with the Board and they took advantage of this opportunity to provide comments on the outcome of EBPC's consultation program through interventions, oral statements, and letters of comment. Given the evidence on the outcome of the consultation program from EBPC and members of the public, it is clear that a number of hearing participants were not satisfied with EBPC's explanation of why no further action was required to address public concerns or comments. The Board has taken into consideration these comments from members of the public in making its public interest determination.

The Board notes EBPC's comments near the end of the evidentiary portion of the hearing, that it recognizes the need to conduct business in an appropriate manner in order to build a reputation as a respected member of the business community and community at large. The Board also notes that EBPC has been successful in securing the support of several intervenors; however, the Board is of the view that EBPC has not been effective in fully engaging the public to date. The current status of the relationship between EBPC and the public could create difficulties for EBPC to become fully engaged as a community partner, and to collaboratively address the ongoing needs of the community with respect to the Project. In order for the public to obtain a fuller understanding of EBPC's commitments with respect to the Project to date, should a Certificate be issued, the Board will further require EBPC to file with the Board and post on its company website, 120 days before the planned start of construction, a table listing all commitments made by EBPC during the proceedings, conditions imposed by the NEB, and the deadlines associated with each (condition 3 in Appendix V). In addition, in order to help improve this relationship in the future and given the amount of interest in the topic, the Board will require, in any Certificate that it may issue, that EBPC file with the Board, for approval, a public consultation program for the construction and operations phases of the Project at least 75 days prior to the planned start of construction. The program shall demonstrate how meaningful and effective public consultation will be achieved during construction and operation, while allowing flexibility for continuous improvement (condition 4 in Appendix V).

The Board believes that these conditions would be critical to ensuring that the foundation is properly established for EBPC and the local communities to be able to effectively interact with each other. The public consultation program should establish a direct communications link between EBPC and the public and provide a means to have all public questions and concerns considered and addressed, if necessary, by the appropriate party. At a minimum, the Board expects EBPC to provide regular progress reports to the community beginning no later than 60 days before the planned start of construction, and continuing every six months for at least two years after the pipeline is commissioned. These progress reports should also include:

* an update on the status of project-related activities;
* a clear summary of results of recent project-related activities;
* summaries from any public meetings; and
* a description of how EBPC has fulfilled or is continuing to fulfill its commitments and conditions, previously submitted pursuant to condition 3.

Given conditions 3 and 4 described above, and EBPC's commitment to ongoing public consultation and corporate responsibility, the Board finds that the consultation program undertaken by EBPC is consistent with the requirements of the NEB's Filing Manual.

In addition, the Board acknowledges and appreciates the time and effort members of the public devoted to the process and the personal contributions they made. The Board notes the frustration expressed by some of the members of the public due to a lack of familiarity with a quasi-judicial process; however, the Board further notes that this lack of familiarity did not impede participants from submitting relevant evidence which the Board analyzed and weighed during its deliberations.

Chapter 6

Environment, Socio-Economic, Routing and Land Matters

6.1 Environmental Assessment under the CEA Act

188 As indicated in Chapter 1, the federal Minister of the Environment approved the Board's use of its own public hearing process for assessing the environmental effects of the Project as a substitute for an EA by a review panel under the substitution provisions of the CEA Act. The NEB EA Report set out the rationale, conclusions and recommendations of the Board in relation to its review of the Project under the CEA Act and included a discussion of recommended mitigation measures and follow-up programs.

189 The NEB EA Report, included as Appendix VII, reflects parties' views and the Board's assessment of the environmental effects of the Project and mitigation measures based on the Project description, factors to be considered and the scope of those factors. Since the full report, including the Executive Summary, is in the Appendix, no portions of the NEB EA Report have been duplicated in this section.

190 Pursuant to subsection 37(1.1) of the CEA Act, the responsible authorities took into consideration the NEB EA Report and, with the approval of the Governor in Council, responded to the EA Report (government response). The government response was approved by the Governor in Council on 17 May 2007 and is included as Appendix VIII to these Reasons. The government response accepts all of the Board's recommendations in the EA Report and provides further expectations, which the Board has taken into account.

191 The Board notes that the government response identifies specific elements for inclusion in the Environmental Protection Plan (EPP). These items were discussed in evidence during the proceeding. The Board would require[25] EBPC to consult with relevant regulatory authorities regarding the mitigation outlined in the EPP. This consultation provides an opportunity for relevant departments to verify that elements, such as those identified in the government response, have been addressed.

192 With respect to environmental follow-up programs, the government response suggests that a specific allowance be made to include other valued ecosystem components, such as Species at Risk, Species of Conservation Concern, and migratory birds, subject to review of completed field studies and surveys and the expert opinion of federal departments. The Board notes that EBPC has committed to consulting with regulatory agencies, including Environment Canada, in 2007 following the submission of the survey results with respect to any issues and mitigation to be developed. The Board would require[26] EBPC to carry out its commitments and consult with relevant regulatory authorities with respect to the mitigation included in its EPP. The Board notes that discussion of any additional follow-up programs that federal departments determine to be appropriate could occur in the context of the development of the mitigation and associated follow-up in the EPP.

193 The government response suggests that the wetland follow-up program be designed to address effects that may endure beyond EBPC's proposed five-year monitoring period and that the determination of appropriate compensation for unavoidable losses be established independent of the amount of time required for natural vegetation. The Board notes that its EA Report indicates it would be appropriate that the follow-up program schedule and associated reporting schedule be designed to address any effects that may endure beyond EBPC's proposed five-year monitoring period. The Board also notes EBPC would be required[27] to develop the follow-up program in consultation with appropriate regulatory agencies and stakeholders. Through this consultation, relevant federal departments would have the opportunity to discuss with EBPC the design of the follow-up program and the determination of compensation for unavoidable losses.

194 The government response reiterates the Board's requirement that the proponent shall prepare an Access Management Plan and an Emergency Procedures Manual. It further adds that these plans shall be prepared in consultation with the appropriate expert federal authorities in a manner consistent with their mandated responsibilities and interests. The Board notes that consultation would be required[28] and expects EBPC to take into account the government response in planning its consultation program.

195 The Board has considered the government response and adopts all of the findings, rationale and recommendations made in the NEB EA Report. These recommendations will be included as conditions in any Certificate that the Board may issue.

6.2 Socio-Economic Matters

196 The NEB defines a socio-economic effect in respect of a project as any effect on a socio-economic element found in Table A-5 of the *Filing Manual*, including direct effects, as well as effects resulting from a change in the environment. In order to mitigate the socio-economic impacts of projects, it is important to deal with both the intended and unintended, positive and negative impacts. Awareness of the differential distribution of impacts among different groups in society should always be of prime concern in a socio-economic impact assessment.

197 EBPC filed a socio-economic assessment for the Brunswick Pipeline Project that considered the potential effects the Project would have on various socio-economic elements. The NEB EA Report sets out the rationale, conclusions and recommendations of the Board in relation to its review of the Project under the CEA Act. The NEB EA Report discussed the potential socio-economic effects resulting from a change in the environment, including effects on heritage resources, human health, human occupancy and resource use, social and cultural well-being, and the current use of lands and resources for traditional purposes by Aboriginal persons. The conclusion reached in the NEB EA Report was that, provided all commitments made by EBPC in its application and undertakings during the GH-1-2006 proceeding were upheld, and the Board's recommendations were implemented, the Project would not be likely to result in significant adverse environmental effects.

198 The Board has considered the remaining direct socio-economic effects under the NEB Act in this section of the Reasons, including effects on employment and economy, services, infrastructure, and property values.

6.2.1 Employment and Economy

199 EBPC stated that the Project lies within the Saint John Census Metropolitan Area (CMA) and Charlotte County. These jurisdictions have partial responsibility for the development and implementation of economic development strategies for their respective areas. The Saint John CMA is New Brunswick's largest urban centre with a population of approximately 140,000.

200 The Province of NB has primary responsibility with respect to the management of economic development throughout the Province. In 2001, NB's gross domestic product (GDP) was estimated to be approximately $27 billion. Some of the leading sectors of the economy include construction, manufacturing, transportation, finance, and retail trade. In 2001, NB recorded a median household income of $39,951, a labour force participation rate of 63.1 percent, and an unemployment rate of 12.5 percent.

201 According to EBPC, during construction, the urban portion of the Project (i.e., the portion within Saint John CMA) is estimated to involve approximately 340 individuals in various jobs, while the rural portion (i.e., the portion within Charlotte County) would involve approximately 580 construction workers, plus supporting staff. These positions would be of varying duration. Total direct employment was estimated at approximately 373 person years, full-time equivalent (FTE). Total Project expenditures were estimated to be $350 million. The total GDP impact from construction activities were estimated at $137 million for the Province and $210 million for the rest of Canada. The gross economic impact was estimated at $529 million for NB and $693 million for the rest of Canada.

202 EBPC stated that during operation and maintenance, total direct employment was estimated at approximately four FTEs. The overall expenditure was estimated at $3.4 million annually. This expenditure would affect various components of the economy, both within NB and in the rest of Canada. The annual GDP impact from operation and maintenance activities was estimated at $2 million for the Province and $2 million for the rest of Canada. The gross economic impact was estimated at $4 million for NB and $5 million for the rest of Canada. The Project would also contribute tax revenues to various levels of government. The preliminary estimated annual taxes included $3.3 million (property), $2 million (federal income tax), $1 million (provincial tax), and $1 million (capital tax) for a total of $7.3 million.

Views of Interested Parties

203 Intervenors in favour of the Project argued that the Project would provide benefits of significance for the City of Saint John and the Province. Intervenors submitted that the Brunswick Pipeline was an infrastructure investment that would support Saint John's "energy hub" industrial development strategy, and as such, the City and region should realize spin-off benefits in terms of jobs and investment from further industrial growth spurred by the availability of long-term gas supply.

204 Several intervenors stated that they could not agree that the "energy hub" strategy was good for Saint John, or that the proposed Project would therefore be a benefit to the community, and believed quite the opposite. In order to support the argument against the "energy hub" strategy, intervenors claimed that Saint John had more industries than any other NB town and also had the highest poverty rates; therefore, it was unclear how the proposed pipeline would accomplish what present industries had not been able to accomplish.

205 Regarding employment impacts, some intervenors highlighted that the Project benefits would be minimal as there would be temporary jobs during the expected one-year construction phase, and a total of only four permanent jobs post-construction. Regarding economic impacts, the Project would generate annual tax revenue of only $1.3 million, with 45 percent going to the provincial government and 55 percent to the municipal government, an amount which intervenors believed to be insignificant.

EBPC's Response to Concerns Raised

206 EBPC submitted that the City and region should realize spin-off benefits in terms of jobs and investment from further industrial growth. Project construction was expected to create direct, indirect, and induced employment and income. Operation and maintenance of the Project would require equipment and personnel, and these effects, although smaller in comparison to the construction phase, were expected to be positive.

207 EBPC indicated that anticipated levels of local and regional economic participation in the Project, in comparison to the total project requirements, were expected to be proportional to those experienced during construction of the M&NP mainline, which were approximately 70 percent, although this would depend on the current labour supply at the time of construction. EBPC submitted that it intended to communicate labour and material requirements to labour unions and local suppliers in advance of tenders to allow the local markets time to prepare for bids and adjust the labour force and training requirements where practicable. This communication may include vendor information sessions. Working with the First Nation organizations, First Nation leadership and the Aboriginal liaisons, EBPC would develop a First Nation contractor list and an Aboriginal human resource list and develop communication protocols to ensure that contracting and employment opportunities would be advertised and shared in a timely fashion with these identified individuals. One element of this plan would include an agreement with the First Nations of NB for an Aboriginal "set-aside" that would target two percent of all third-party contracted services for NB Mi'kmaq and Maliseet businesses.

208 EBPC submitted that the benefits of the Project would be shared by many, and that this new source of long-term gas supply was welcomed by participants in the gas markets located in Maritime Canada. EBPC further submitted that, over time, willing buyers would contract for the new long-term gas supply both to diversify existing supply and to support market growth.

Views of the Board

The Board notes that during the construction phase of the Project, there would be numerous economic and employment benefits. There would also be numerous inconveniences and disruptions for the general public associated with the construction phase of the Project, which have been considered by the Board in other sections of the Reasons and the EA Report.

The Board also notes that, during the operations phase, there would be economic and employment benefits for Saint John and the region. The weight to be attributed to these benefits is debatable because of the limited significance of these benefits, and the offset of these benefits with matters which tend to be difficult to quantify, such as the lack of certainty of increased access to gas for local residents.

As further discussed in Chapters 4 and 7, Maritime Canada access to an additional supply of natural gas through the Brunswick Pipeline has the potential to generate economic benefits for the area. If demand exists in the future in Saint John for additional supplies of natural gas, then the Board expects that parties will be able to reach a mutually acceptable agreement to serve the local market.

With respect to the potential socio-economic impacts of the "energy hub" strategy, the Board notes the concerns of certain parties and is of the view that a determination on the appropriateness of this strategy is beyond the mandate of the Board under the NEB Act.

The NEB promotes the identification and consideration, by regulated companies, of the effects of projects on individuals, groups, communities and societies; including a project's positive and negative socio-economic impacts and any proposed enhancement and mitigation measures.

Some industry stakeholders have investigated ways to turn impacted people, communities and societies into positive beneficiaries. The Board notes that some of these ways have been specifically related to impacts of the proposed projects while others have been related to local or regional interests.

The Board is of the view that EBPC could have pursued additional opportunities to improve its role and contribution to Saint John and Maritime Canada. The Board recommends that EBPC re-evaluate whether its role and contribution within Saint John and Maritime Canada have been maximized. Seeking ways in which EBPC could enhance its role in and commitment to the community could improve the public's perception of EBPC, its commitment to responsible corporate conduct and its desire to build a long-term partnership with Saint John and other communities throughout New Brunswick.

Notwithstanding the observations above about EBPC's role in the community, the Board finds, with respect to the impacts of the Project, that its positive and negative impacts on employment and economy have been adequately identified by the parties and considered by EBPC. Further discussion of the weight attributed to these benefits and burdens and the balance of overall benefits and burdens of the Project is found in Chapter 8 of these Reasons.

6.2.2 Services

209 The Project has the potential to impact both local services (e.g., accommodation), and emergency and medical services (e.g., health care, policing and fire protection).

210 The Saint John Regional Hospital is a 700-bed acute care teaching hospital, and is accessed via either University Avenue or Sandy Point Road. It is NB's largest regional hospital and one of the largest in eastern Canada. EBPC stated that the Saint John Regional Hospital is located approximately 650 m from the preferred corridor and EBPC did not expect that it would fall within the Project's EPZ.

Views of Interested Parties

211 Many intervenors were concerned about the proximity of the Saint John Regional Hospital to the pipeline corridor, and the potential consequences of any incident on the pipeline. One intervenor argued that EBPC had not reviewed safety issues with the SJFD Chief, EMO or medical experts prior to choosing its preferred pipeline corridor.

212 Another intervenor argued that taxpayers and the City would end up bearing additional costs associated with hospital and fire services.

213 One oral statement provider noted that the hospital was not ready for any major incident because the hospital had not practiced a major exercise in over 10 years.

EBPC's Response to Concerns Raised

214 EBPC submitted that it would engage the SJFD and other first responders in southern NB in the development and finalization of an ERP. This plan would be compliant with regulatory requirements and achieve the concurrence of the SJFD. EBPC's emergency planning, first responder training and public education programs would be subject to NEB requirements under the OPR-99 and CSA Z731. Further discussion of EBPC's ERP and public safety is contained in Chapter 3 and the EA Report.

215 Regarding the argument that EBPC did not review safety issues with the SJFD Chief, EMO or medical experts prior to choosing the pipeline route, EBPC claimed that the record was quite clear that the pipeline route itself had not yet been chosen, as the detailed routing process was ongoing. However, in discussing the public safety related to the preferred corridor with the SJFD Chief, EBPC had addressed all of the recommendations made within the SJFD Risk Analysis Report.

216 EBPC submitted that while pipeline incidents with the potential to impact public safety were highly unlikely, it is critical to have a well-rehearsed ERP. The ERP would ensure proper coordination with the City's first responder services, including those of the fire department.

217 In order to mitigate any potential effects on accommodation, EBPC proposed an accommodations plan for construction workers. EBPC expected that the workforce requirements would be similar to those that were required for the construction of the SJL, and the facilities available in Saint John and along the preferred corridor would be adequate to accommodate the increased usage.

Views of the Board

EBPC has appropriately identified potential emergency and medical services issues related to the Project and has committed to address the issues with local service providers. EBPC would also be required to conduct a full emergency response exercise within six months of commencement of operation of the Pipeline as set out in condition 21, which would be imposed should the Project application be approved and as discussed further in Chapter 3. Given the above, the Board finds that EBPC has adequately considered the Project's impacts on emergency and medical services.

Although not determinative, the Board notes that EBPC has secured the support of the City of Saint John, which has the responsibility for emergency services and first response. Based on the support of the City of Saint John for the Project, it is reasonable to conclude that the City's concerns have been or will be addressed to its satisfaction.

Given the accommodations plan for construction workers and the previous experience with the construction of the SJL, the Board finds that there are not likely to be negative impacts on accommodation.

6.2.3 Infrastructure

218 EBPC committed to working with the City of Saint John to ensure that the design, construction, and operation of the proposed pipeline would not impinge on existing infrastructure. Allowances would be made for future infrastructure if it could be identified in advance so the installation of that infrastructure is not hampered. EBPC indicated that ongoing discussions with the City and owners of private infrastructure are taking place as a component of the detailed routing process.

Views of Interested Parties

219 Several intervenors, oral statement providers, and letters of comment raised concerns regarding the change in subsurface infrastructure including, but not limited to, the examples in the following paragraphs.

220 The SJFD Risk Analysis Report stated that the natural gas pipeline, once in the ground, would pose a serious obstacle to any future development. The proposed pipeline would be physically in the way of underground utilities - water, sewage, drainage, telephone ducts, electrical ducts, buried cables and other structures usually found buried in the street RoW (there would also be a substantial area below and above the pipeline that would not be accessible for future utilities). The proposed pipeline would restrict the type of construction activity that could be undertaken, even simply resurfacing the ground.

221 One intervenor argued that there would be no adequate or feasible way to provide necessary city services and roads to service the proposed development on his investment land. Another intervenor argued that EBPC's pipeline should not take precedence over infrastructure extremely important to the survival and well-being of citizens. One intervenor argued that there were a very large number of costs associated with a critical water main break that could shut off water for three days, closing down businesses, schools, hospitals and affecting water pressure to the entire City. Other concerns included restrictions on the ability to construct new streets and roads, and the future costs that would be applied to future development in the event the City wished to place water and sewer lines into a new residential or business development around the constructed pipeline.

222 FORP commissioned a study by the Pembina Institute entitled "Impacts of the Proposed Brunswick Pipeline on Municipal Infrastructure Maintenance Costs in Saint John" (Pembina Infrastructure Report). The conclusions of this Report were:

> The proposed Brunswick Pipeline may generate additional costs that would be borne by the city during maintenance of underground infrastructure (water main, sanitary sewers, and storm sewers) and roads. The average additional annual cost of maintaining underground infrastructure is estimated at $7,700/yr, primarily due to prohibited mechanical excavation within three metres of the pipeline and due to the risks associated with working in the vicinity of the pipeline. The average additional annual cost of resurfacing roads is estimated at an average of $34,000/yr for 20 years, primarily due to the anticipated shortened life of the roads following pipeline construction.
>
> Two mitigation strategies that may reduce the costs to the City include installing the pipeline three metres below water mains, sanitary sewers, and storm sewers and scheduling road maintenance to coincide with the construction of the pipeline.

EBPC's Response to Concerns Raised

223 EBPC stated that the pipeline would be expected to have no significant impact on the City's infrastructure, and any construction-related effects would be short-lived and remediated because, among other things, the final RoW alignment and pipeline design would avoid all such infrastructure to the extent practicable; all subsurface infrastructure would be located prior to excavating and EBPC would work closely with utility companies, landowners, and municipalities, including the City of Saint John, to identify and avoid all subsurface infrastructures such that disruptions to services would not occur as a result of pipeline installation. If absolutely necessary, interruptions should be of very short duration. Furthermore, where justified, costs for any alterations to existing infrastructure would be borne by EBPC.

224 EBPC submitted that close coordination with local officials would be critical to ensure impact upon local utilities and public infrastructure would be minimized. EBPC stated that it continues to meet with those officials, including working with the SJFD, the Saint John EMO and other City representatives, with the objective of resolving the infrastructure concerns identified. EBPC committed to developing special design solutions for the proposed pipeline, in consultation with City officials, where critical City of Saint John or third party infrastructure would be in close proximity to the final pipeline location within the proposed corridor. These solutions could include added pipeline burial depth, increased separation distances and other pipeline or infrastructure protection measures and would be in accordance with good engineering practice, national engineering design codes and NEB regulations.

225 EBPC would also work with local developers for any proposed new subdivisions or developments to design the pipeline to minimize adverse environmental effects and interactions between the proposed developments and the pipeline. In situations where fair accommodation could not be reached, EBPC would compensate the landowner or developer for their demonstrated losses. EBPC indicated that the regulatory process would ensure a fair determination of market value in the event the parties could not agree to it themselves. Once the detailed route selection process was completed, EBPC would discuss measures to address any changes or restrictions to land use with affected developers, including compensation where warranted.

226 In its response to the Pembina Infrastructure Report, EBPC concluded that there would be some additional costs incurred by the City of Saint John due to the presence of the pipeline, but disagreed with the total costs. EBPC noted that the estimated taxes for the portion of the pipeline within City limits would be around $1.3 million per year, approximately $700,000 of which would be distributed to the City of Saint John based on EBPC's interpretation of the Province's municipal tax regulations. According to EBPC, any minor financial burden that may be imposed on the City would be more than offset by the anticipated additional municipal taxes.

227 EBPC also submitted, given that the additional cost impacts would be insignificant, there was no need to have the proposed pipelines buried at such extreme depths or routed to completely avoid municipal infrastructure. These mitigative strategies would add significant costs to the proposed pipeline project and far outweigh the benefits. EBPC indicated that it would discuss timing of planned road resurfacing with the City in order that the construction of the pipeline and resurfacing of the streets is appropriately coordinated, as part of the detailed routing process.

228 Moreover, the City of Saint John, after considerable consultation, indicated its support for the preferred route. EBPC submitted that this suggests that any potential impacts on its infrastructure had been mitigated to the City's satisfaction.

Views of the Board

The Board recognizes that issues can arise when underground infrastructure is located in close proximity to a pipeline, and for this reason the Board has developed specific requirements in the *National Energy Board Pipeline Crossing Regulations* (Crossing Regulations). Prior to construction, the Board will require, in any Certificate that it may issue, that EBPC identify all underground infrastructure utilities to be crossed by the Project, and confirm that all the agreements or crossing permits for those facilities to be crossed have been acquired or will be acquired prior to construction (condition 13 in Appendix V). Given EBPC's proposed mitigation measures, compliance with the Crossing Regulations, its commitment to work with the City of Saint John and local developers, and condition 13 described above, the Board finds that EBPC has adequately considered the Project's impacts on infrastructure.

While EBPC's evidence on additional infrastructure costs that could be borne by the City if the Project were built differed from those of the Pembina Institute, no evidence was available from the City to assist the Board in making a determination of an expected impact on costs. The Board notes, however, that EBPC has secured the support of the City of Saint John, which has the responsibility for construction and maintenance of municipal infrastructure. The Board is of the view that this permits the conclusion that the City is satisfied with EBPC's proposed measures to address the potential impacts on municipal infrastructure.

Further, regarding the two mitigative strategies proposed in the Pembina Infrastructure Report, the Board notes EBPC's willingness to work with the City and local developers, and therefore does not find it necessary to attach any additional conditions regarding the depth of burial for the pipeline or the scheduling of road maintenance to coincide with the construction of the pipeline.

6.2.4 Property Values

229 EBPC stated that it would be paying all landowners, including the City of Saint John, market value for any easements it requires. EBPC did not expect that any homes would need to be removed as a result of the Project. If it became apparent during the detailed route selection process that it would not be possible to avoid any particular residence, EBPC would purchase the residence at fair market value prior to construction.

230 EBPC would work with local developers for any proposed new subdivisions or development to design the pipeline to minimize adverse environmental effects and interactions between the proposed development and the pipeline. In situations where fair accommodation could not be reached, EBPC would compensate the landowner or developer for their demonstrated losses. The regulatory process for compensation matters, through Natural Resources Canada, could be used to make a determination of market value in the event the parties could not agree to it themselves.

231 EBPC filed a study entitled "Impact of Natural Gas Pipelines on the Value of Residential Real Estate" by de Stecher Appraisals Ltd. (de Stecher Study). The hypothetical pipeline whose impacts were considered in the de Stecher Study was based on the specifications of the proposed Project. The Study came to the following conclusions:

> After identifying several neighbourhoods where relevant data was found to be available, an analysis of the data revealed that there was no discernable impact on the market value of residential property due to the presence of a natural gas pipeline. As the data included both vacant lots and improved property and involved several disparate markets, the findings are considered transferable to other similar situations.

> In summation, after conducting a review of available literature, interviewing knowledgeable appraisers, analyzing relevant market data and investigating the availability of insurance, it is concluded that there is no evidence to suggest that the presence of a natural gas pipeline has any impact on the market value of residential property located in close proximity to a pipeline.

Views of Interested Parties

232 Intervenors submitted information on a number of studies regarding property valuations with respect to energy transmission projects, arguing that there was a connection between a decrease in property values and proximity to natural gas pipelines.

233 One intervenor argued that EBPC's study of the local marketplace (the SJL, which in his view is a distribution line to residences and small businesses) cannot separate proximal benefits (e.g., increased employment, options for heating and cooking) from proximal costs (e.g., risk of an explosion/fire, limitations to property development), and therefore believed that the de Stecher Study was largely meaningless.

234 Another intervenor argued that the proposed pipeline did not belong in his yard or through his holding property. In his view, his family's personal home would be destroyed, his corporation's medical practice would be closed, their corporate lands would be ruined, and any and all of their present and future investments would be extinguished if this were to occur. Saint John residents, in general, would not receive any local distribution benefits; therefore, he argued that the Project should not be considered the same as the SJL because the SJL was servicing Saint John customers, including EGNB, which was supplying gas to ordinary Saint John citizens for space and water heat. Further, the intervenor submitted that one could not extrapolate EBPC's local market study (based on smaller, existing transmission and distribution feeds) to a different situation with a much larger, transmission-only pipeline that Saint John residents may receive minimal direct benefits from but be expected to bear all the risk and very real burdens both now and in the future.

235 According to another intervenor, to conclude that there would be no effect on property value has little credibility and makes little common sense; very few people would want to purchase a property near or on a 1440 psi pipeline assembly. Consequently, value would have to be lost.

236 One oral statement provider suggested that EBPC be required, as a condition of approval, to purchase the property at fair market value of any owner within 500 feet of the pipeline who wishes to sell their property. He also requested a preliminary order from the NEB to EBPC to cover all interest costs for his project from the date of the pipeline reaching public consciousness in spring of 2006 to the date of the NEB decision in 2007.

EBPC's Response to Concerns Raised

237 EBPC did not anticipate that the Project would result in a measurable change in local property values. Since the preferred corridor had been selected to minimize disruptions to existing land use, the likelihood of adverse environmental effects on property value from changes to land use would be minimized. Further, during operation, adjacent lands would not be exposed to substantial public health and safety risks. EBPC indicated that the low level of risk (i.e., the quantitative risk of pipeline ruptures or leaks) was not anticipated to result in a significant economic risk that would affect property values. In addition, it argued that there were a number of existing natural gas pipelines within Saint John, thus the public is becoming more accustomed to this technology. Given all of these factors, EBPC submitted that it is not likely that property values would be adversely affected as a result of the Project, and the environmental effects of the Project on property values were considered by EBPC to be not significant.

238 While several residents had requested that EBPC provide independent assurance regarding the impact the presence of a natural gas transmission pipeline might be expected to have on residential property values, EBPC submitted that there would be no impact to property values of homes adjacent to pipelines, as confirmed by the de Stecher Study of Maritime specific areas. As part of the de Stecher Study, inquiries were made of insurance agents to determine if the presence of a natural gas pipeline would impair the ability to obtain home insurance. The Study concluded that, based on the information obtained from the three local insurance agents, it would appear that the presence of a natural gas pipeline would not make it more difficult or more costly to obtain insurance on a residential property in the local marketplace.

239 The de Stecher Study provided the most localized evidence of the lack of impact natural gas pipelines have on property values. The Study included a review of properties in two residential areas near the M&NP SJL and one near the M&NP Halifax Lateral. In Saint John, the Study reviewed properties in the Bentley Crossing area that are encumbered by an easement for the SJL. Further, the Study noted that the development of the Bentley Crossing subdivision in Saint John and the Miller Lake West subdivision in Halifax, Nova Scotia both occurred after the pipelines had been installed. The conclusions of the de Stecher Study were based, therefore, upon actual experience with high pressure gas pipelines in Maritime Canada, and in the City of Saint John itself.

240 Although some intervenors questioned the use of Bentley Crossing subdivision in Saint John and Miller Lake subdivision near Halifax as areas similar to those affected by the proposed Brunswick Pipeline, EBPC submitted that these subdivisions and situations were similar to the Brunswick Pipeline and were local. EBPC argued that this was consistent with the information requested by the public and had led EBPC to commission the de Stecher Study.

Views of the Board

Much of the debate on this topic in the hearing focused on whether the existence of a high pressure natural gas pipeline would have a measurable impact on property values. EBPC argued that there was no impact to the value of homes adjacent to pipelines, and supported these claims with the de Stecher Study of Maritime-specific areas. Intervenors referenced studies regarding property valuations with respect to energy transmission projects and argued that common sense indicated that people prefer property that is not adjacent to a pipeline, and therefore, there must be an impact on property value. In addition, it appeared that several intervenors disputed the relevancy of the conclusions of the de Stecher Study because of dissimilarities between the Brunswick Pipeline, the M&NP SJL and the M&NP Halifax Lateral; the size, the pressure, and the purpose of the three pipelines were different. Given these differences, their argument was that a study based on the SJL should not be used to predict the impacts on property values of the Brunswick Pipeline.

While the Board notes that there are differences between previous projects and the Brunswick Pipeline, the Board accepts that the conclusions of the de Stecher Study on property values are relevant to the Brunswick

Pipeline Project because the study was based upon actual experience with high pressure gas pipelines, such as the SJL in Maritime Canada, and in the City of Saint John itself. The Board did not find evidence contained within the other studies regarding property valuations that would cause the Board to question the conclusions contained within the de Stecher Study.

Two factors discussed in this hearing that could negatively impact property values for properties near the Project are increased public awareness and pipeline accidents and malfunctions. The increased public awareness associated with the pipeline hearing has created some negative public perceptions; however, this would likely dissipate over time as the public becomes more accustomed to the presence of the pipeline and becomes more informed, for example, through EBPC's public awareness and public consultation programs.

Any accidents and malfunctions associated with the pipeline could also negatively impact property values. The Board notes that the NEB EA Report concluded that it is unlikely that the Project would result in significant adverse environmental effects from a pipeline leak or rupture. In addition to EBPC's Environmental Management Framework, there are multiple layers of protection to ensure the safe operation of a pipeline. This was discussed more fully in section 3.4.3.2 of these Reasons where the Board concluded that the provisions of OPR-99 and the audit programs of the NEB, in conjunction with EBPC's commitments and fulfillment of relevant Certificate conditions (18, 19, 21 and 22), are sufficient to ensure that the Brunswick Pipeline will be operated in a safe manner.

As a result of the Board's conclusions on these two factors, and its acceptance of the de Stecher Study conclusions, the Board finds that any negative socio-economic impacts on property values would be unlikely, or short-term and reversible.

Given this finding, the Board has decided that it is not appropriate to require EBPC to purchase the property, at fair market value, of any owner within 500 feet of the pipeline.

6.3 Routing and Land Matters

6.3.1 Corridor Selection

241 Many of the issues raised with respect to corridor selection and evidence on these issues were discussed in section 3.3 of the NEB's EA Report, attached as Appendix VII to these Reasons. The following section should be read in conjunction with that section of the EA.

242 EBPC noted that several alternatives had been evaluated to connect the Canaport TM LNG Terminal at Mispec Point with M&NP US in the vicinity of the international border near St. Stephen, NB. EBPC stated that a multi-disciplinary Project team, assisted by various consultants, had been assembled to evaluate corridor alternatives and select a preferred corridor for the Project.

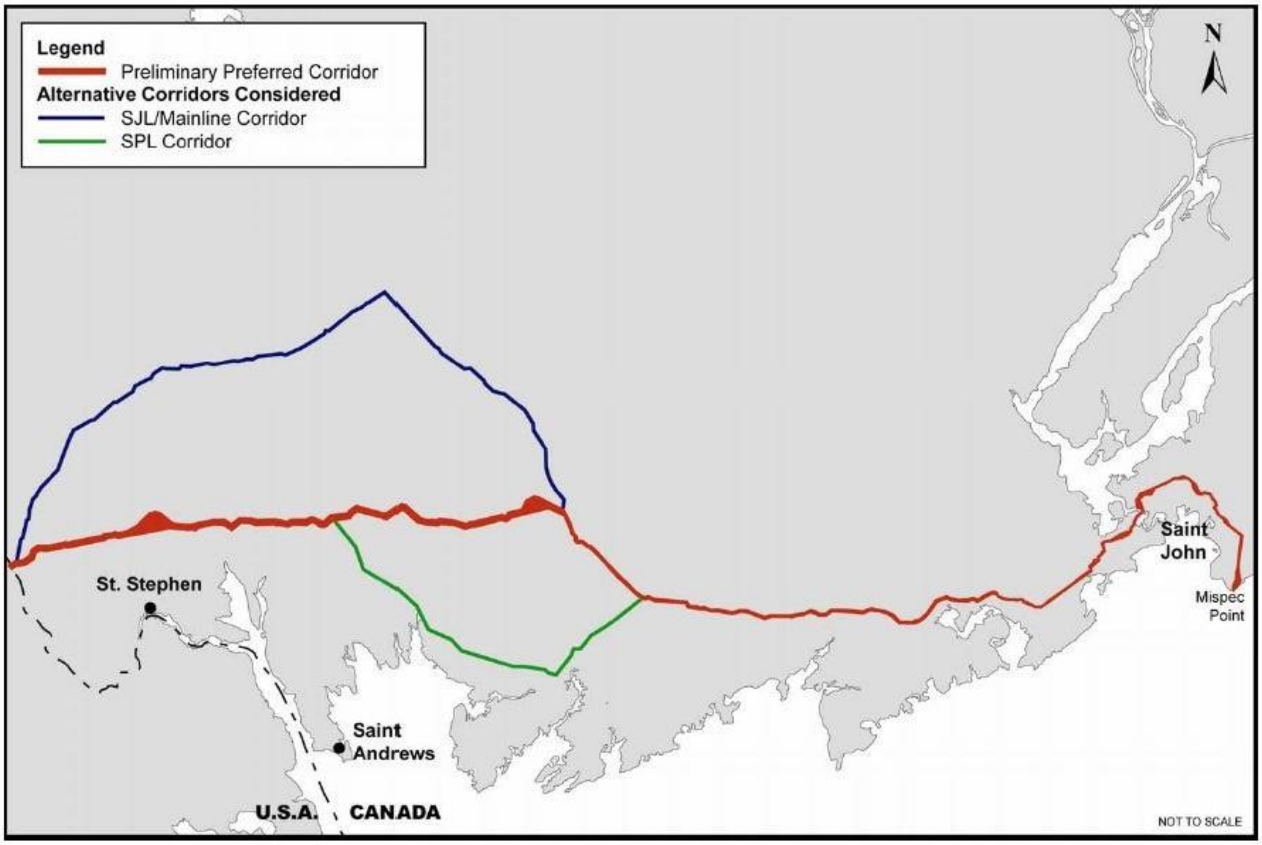
243 EBPC submitted that the preferred corridor was selected on the basis of:

* safety;
* constructability;
* minimizing Project cost;
* impacts to Project schedule; and
* environmental constraints.

244 The corridor evaluation and selection approach was divided into urban and rural components, separated at a point on the west side of Saint John near the community of Colpitts. Three main rural alternatives were assessed (Figure 6-1), all of which would initially parallel the existing M&NP SJL pipeline until each one would diverge to intersect and follow other existing or approved utility RoWs. EBPC stated that the Project team selected the central alternative, referred to as the International Power Line (IPL) alternative, as the preferred rural corridor largely due to its shorter length, smaller area required for new RoW, better constructability, and lower potential to interact with environmental constraints.

Figure 6-1

Proposed Pipeline Corridors Showing Rural Alternatives

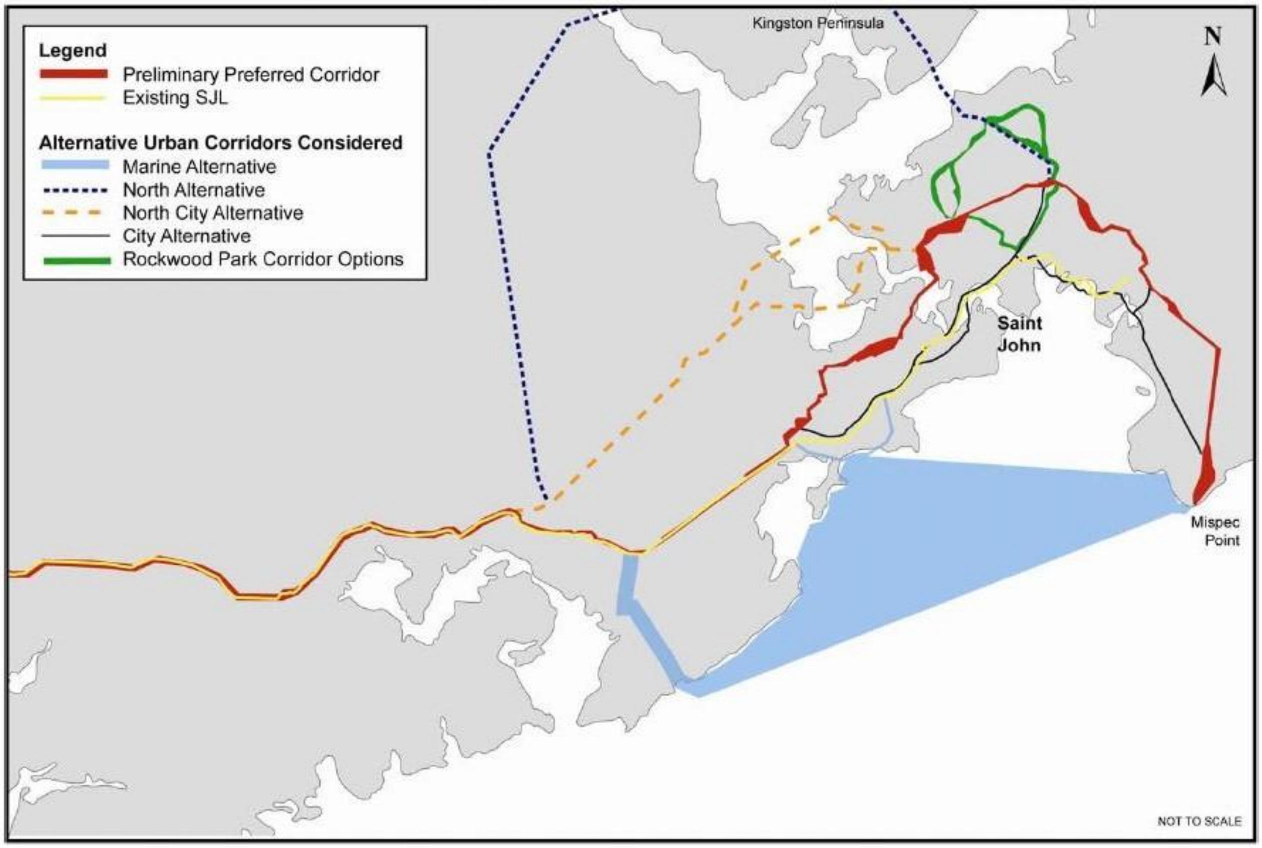


245 Corridor alternatives considered for the urban portion included two marine crossing routes of Saint John Harbour and three onshore routes (Figure 6-2). EBPC submitted that a marine crossing was considered thoroughly but rejected at an early stage in the selection process due to the cumulative effects and impracticalities of higher safety, technical, cost, schedule, and environmental risks.

Figure 6-2

Proposed Urban Pipeline Corridors Showing

Urban Alternatives



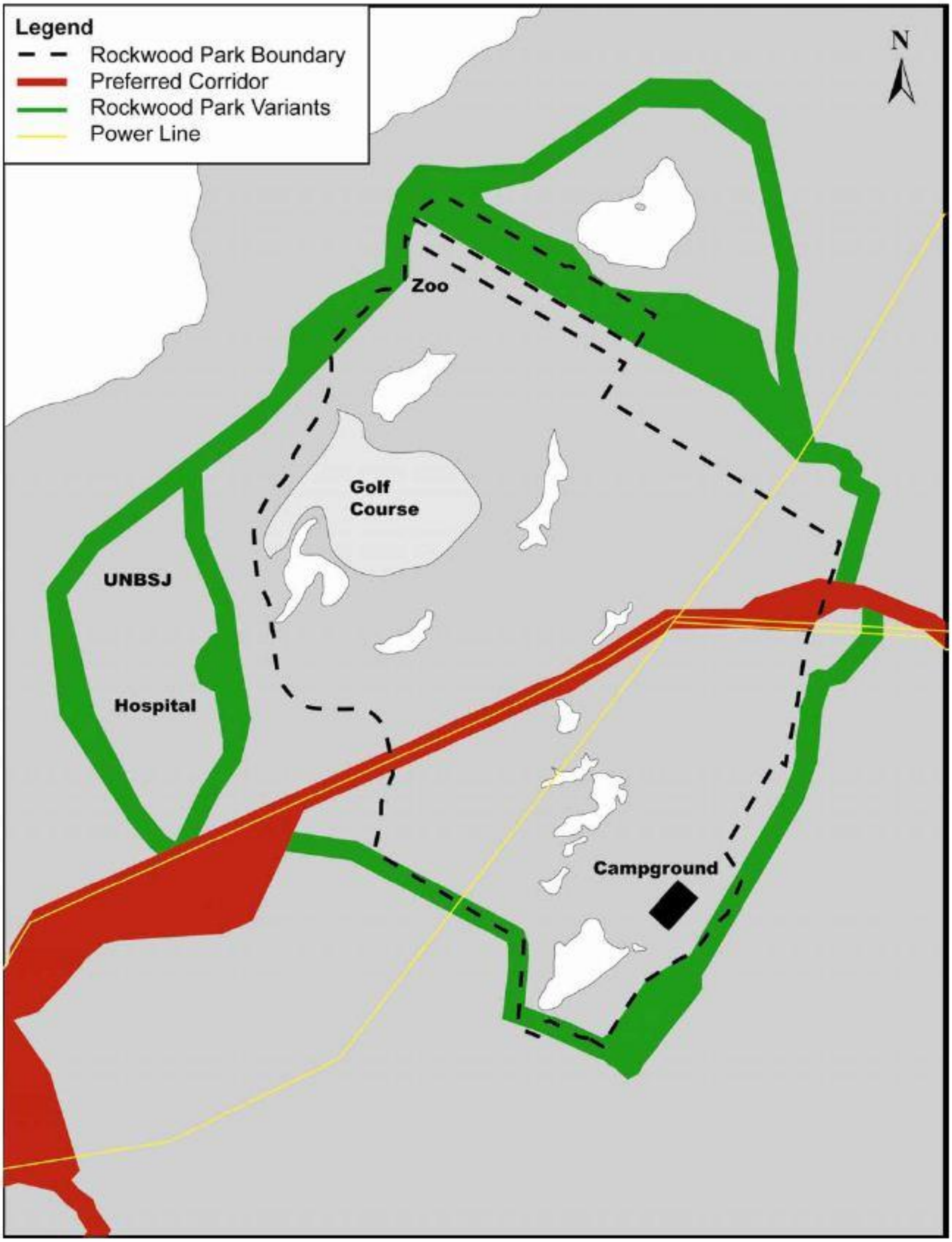
246 The three main onshore urban corridor alternatives followed a similar route from Mispec Point to the east side of the City, whereupon they would diverge: one paralleling the existing M&NP SJL pipeline through the City, another following an existing power line through Rockwood Park, and another heading northward and westward across the Kingston Peninsula (Figure 6-2).

247 EBPC stated that the Project team selected the Rockwood Park alternative, referred to as the Pleasant Point sub-alternative, as the preferred urban corridor largely because of its combined features of constructability and length compared to the other two alternatives.

248 EBPC noted that in response to initial public concerns and opposition to its choice of the preliminary preferred corridor through Rockwood Park, two possible variants were identified that would largely avoid the Park (Figure 6-3). EBPC submitted that both variants were found to be inferior to the preferred corridor through Rockwood Park because they were longer, would impact approximately 50 additional properties and a number of residences, and would either create new RoW or potentially parallel existing and future roads.

Figure 6-3

Rockwood Park Variants and Preferred Corridor


Legend
Rockwood Park Boundary
Preferred Corridor
Rockwood Park Variants
Power Line
N
Zoo
Golf
Course
UNBSJ
Hospital
Campground

249 EBPC confirmed that the preferred corridor through Rockwood Park was the corridor for which it was seeking approval. EBPC submitted that it would only seek approval for either of the two variants, both of which have been assessed on a preliminary basis, should the Board not approve its preferred corridor.

250 EBPC noted the following features of its preferred corridor:

* compared to the Rockwood Park variants, the Rockwood Park route would follow the existing power line utility corridor, would avoid impacts to residences, would not alter existing land use, and would be the shortest option, which would result in the least impact during the construction phase;
* approximately 95 km of the 145 km corridor would follow and include existing or planned RoWs, including power lines, pipelines, highways, and roads; and
* it would follow good planning practices by paralleling utility corridors, which would allow for overlapping of RoWs, thus reducing the need to clear new RoW areas.

251 EBPC noted that the width of the urban portion of its preferred corridor was generally 100 m. It submitted that segments of the rural corridor that would follow the M&NP RoW were typically 200 m wide, and would increase to generally 500 m in width for the portions following the approved NB Power IPL RoW (Figure 6-1). EBPC submitted that the narrower urban corridor was designed to allow for adjusting the final location of the pipeline RoW while minimizing the impact on local surroundings. Although the urban portion of its preferred corridor was normally 100 m wide, EBPC stated that certain corridor segments would be wider to accommodate areas where EBPC considered it necessary to have more options for eventually locating the pipeline RoW.

Views of Interested Parties

252 Several intervenors and members of the public identified concerns with or opposition to EBPC's preferred corridor, and challenged the rationale and justification for its selection. Concerns and opposition focused almost entirely on the urban portion of the preferred corridor, particularly with regard to the portion passing through the City of Saint John and Rockwood Park. Although some people disputed specific positions or suggested alternate locations for the overland corridor, most opposed any form of terrestrial route through Saint John in favour of a marine route across Saint John Harbour, suggesting that it would be less intrusive and would pose less of a burden on Saint John citizens.

253 Concerns and opposition were identified through the following:

* information requests, evidence, cross-examination, and arguments from several intervenors supporting the marine alternative and challenging the preferred corridor location;
* FORP submitted a petition signed by more than 15,000 people, requesting that the Board permit only an undersea route for a natural gas pipeline in the City of Saint John, refusing any route through Rockwood Park or near any residential areas;

* EBPC's records indicated that during its initial contact efforts, many landowners located within the preferred corridor raised concerns or opposition to the corridor passing through Rockwood Park or the City;
* a vast majority of the 184 letters of comment filed with the Board indicated concerns or objections to the preferred route, many of which suggested a marine route instead; and
* the majority of those who gave oral statements raised concerns or opposition to the preferred corridor passing through Saint John and/or Rockwood Park, with some indicating preference for a marine route.

254 Concerns and opposition focused on the potential for adverse effects caused by the construction and long-term presence of a high-pressure natural gas pipeline passing through a highly populated urban area and Rockwood Park, such as:

* environmental impacts to Rockwood Park including habitat loss, landscape damage, wildlife disturbance, and induced all-terrain vehicle use and trespass;
* threat of further industrialization in the Saint John area;
* risks posed on community safety and security;
* challenges and restrictions to access and emergency response;
* disturbance and nuisance to communities and residents;
* risk of damage and interference to municipal infrastructure;
* disruption and loss of landowners' use, enjoyment, and opportunities for development of their properties; and
* property devaluation.

255 Several intervenors submitted evidence, and questioned EBPC, to support their objections to an onshore route and their contentions that a marine route would be a viable option. Some intervenors asserted that:

* dismissal of a marine crossing was overly dictated by concerns associated with permit scheduling and costs rather than a full presentation of the facts;
* the application appeared to be favouring an on-land route through the City by misrepresenting or over-estimating the difficulties, costs, and risks associated with the harbour crossing while understating the risks associated with the preferred corridor;
* there was an insufficient level of analysis on a marine corridor alternative, and that there should be a more detailed review of such an alternative before a final corridor selection decision is made; and
* corridor selection was discriminatory or influenced by such matters as Irving interests or the income profiles of affected communities.

256 Some participants also raised concerns about the adequacy of public and stakeholder consultation in the corridor selection process, arguing that:

* there was insufficient consultation with those people most affected by the preferred corridor;
* only a very small percentage of City residents were able to ask questions of EBPC and see its justifications for the chosen corridor before an application was filed with the Board;
* specific meetings held with the communities of Milford, Millidgeville, and Champlain Heights to discuss routing issues were initiated by local politicians and the general public, not by EBPC; and
* there was insufficient or inconsistent information, and limited time was provided by EBPC for review or comment in the corridor selection process.

EBPC's Response to Concerns Raised

257 EBPC submitted that it was confident with its approach for selecting its preferred corridor, and that its preferred corridor would be the most appropriate and prudent location for the Brunswick Pipeline.

258 EPBC noted that it had carefully considered a marine crossing and determined that it was not an option for the Brunswick Pipeline, even if its preferred corridor were to be rejected. EBPC also stated that the feasibility studies carried out on its marine alternatives constituted an appropriate level of analysis, and that these studies provided conclusive evidence that, when looking at all of the factors on balance, the preferred corridor was superior and therefore detailed studies on a marine crossing were not required. In response to intervenor evidence submitted in favour of an additional alternative marine route and questioning on this alternative, as well as EBPC's original marine alternatives, EBPC indicated that it did take another look at a marine crossing with this information in mind but determined that it would not lead to a different result in its analysis.

259 EBPC noted that its multi-disciplinary Project team used a balanced approach to account for all five key criteria in corridor evaluation and selection and that no particular criterion was given more importance than the others. EBPC asserted that property ownership, such as proximity to Irving-owned properties, did not influence corridor selection, and that Irving representatives did not participate in the corridor selection process. These assertions were confirmed by an Irving Oil representative during the proceedings.

260 EBPC indicated that a key objective for carrying out consultation activities was to solicit input regarding Project routing and design in order to minimize Project impacts, including taking input from the general public and community leaders into significant consideration in the planning of the corridor. EBPC stated that:

* its September 2005 open houses were intended to advise the public that it had completed a preliminary evaluation of corridor alternatives and to present and discuss its chosen preliminary corridor;
* concerns raised about Rockwood Park during and after these open houses led to EBPC developing the two preferred Rockwood Park variants, which were presented at a supplemental open house held in December 2005 to get further feedback; and

- this feedback had been taken into consideration in making the decision to file the preferred corridor in the application.

261 EBPC stated that it had reviewed all of the feedback from the open houses and still concluded that the selected corridor was the preferred corridor.

262 EBPC noted that all owners of properties within or crossed by the preliminary preferred corridor, as far as could be identified, were sent notification letters to advise them that the preliminary preferred corridor had been identified in their area and to notify them of the September 2005 open houses. For those not able to attend the open houses, EBPC offered to have one of its RoW agents meet with them to provide more detailed information. EBPC also undertook to have its RoW representatives directly contact every landowner identified in the corridor to explain the Project, seek permission for field survey access, and answer any questions. EBPC stated that, as of November 2006, approximately 89 percent of contacted landowners gave permission for it to access their properties to conduct further studies, and EBPC has offered to consult further with these landowners at their request.

263 EBPC submitted that all contacts with landowners are continuously tracked in a database to ensure that comments, concerns, and requests regarding matters such as routing, property impacts, and land-use conflicts are recorded and addressed. EBPC also described its system for recording and tracking ongoing landowner consultation efforts beyond corridor selection. As of November 2006, 717 individual files have been opened on landowners either directly or indirectly affected by the Project who have contacted EBPC or have been visited by RoW agents. EBPC submitted that "initial contact reports" for all potentially directly affected landowners were being completed by RoW agents to track site-specific issues and lands information to guide detailed route planning. EBPC stated that a pre-construction report would be completed for all directly affected landowners, and that this information would be entered into EBPC's construction line list to be used throughout construction and operation.

264 According to EBPC, feedback provided by landowners and other stakeholders led to several modifications to the width and position of its preliminary preferred corridor prior to filing its application. Subsequent to its application, EBPC proposed three more corridor changes, supported by the affected landowners, involving site-specific corridor widening to provide more detailed routing options to address specific issues identified by potentially affected landowners.

265 EBPC stated that it has garnered the support for its proposed corridor location from the duly constituted authorities within Saint John, within Rockwood Park, and from most of the owners of the RoWs that the Brunswick Pipeline proposes to share. EBPC submitted that it had consulted extensively with the City of Saint John and the Saint John Horticultural Association, the co-stewards of Rockwood Park, to address issues regarding public safety, municipal infrastructure, and lands impacts, and to ultimately demonstrate that with appropriate mitigation, the preferred corridor would be acceptable to these parties. Consequently, letters and a resolution of support for the preferred corridor were filed by the Rockwood Park co-stewards. Furthermore, an agreement was reached between EBPC and NB Power to resolve issues and concerns regarding pipeline design, construction, operation, and maintenance in proximity to NB Power infrastructure. NB Power confirmed that it did not oppose the preferred corridor, which follows approximately 35 km of its existing or planned RoWs, including the RoW through Rockwood Park.

Views of the Board

The Board notes that EBPC confirmed that its preferred corridor through Rockwood Park was the corridor for which it was requesting approval in this application, and that EBPC would only propose to seek approval of the two Rockwood Park variants if the Board did not approve its preferred corridor.

The Board finds that the preferred corridor put forward by EBPC is appropriate. The Board finds that EBPC has established a logical and reasoned approach to its selection of the five criteria used for evaluating potential pipeline corridors and the Board accepts these five criteria as being appropriate for the purpose. The Board considers the corridor selection process implemented by EBPC, including the use of a multi-disciplined Project team, the balanced use of five key criteria, and the comparative evaluation of several urban and rural routing alternatives, to be sound given the nature and setting of the Project. Although some intervenors disputed the dismissal of a marine crossing, the Board finds that the depth of analysis undertaken by EBPC and its findings with regard to a marine alternative are reasonable in this case, based on the results of its feasibility studies, as measured against EBPC's five key criteria and as tested and clarified through intervenor evidence and questioning as allowed by the Board. Further discussion of this matter is provided in the NEB EA Report (Appendix VII).

The Board recognizes the concerns raised by some parties regarding the choice of an overland route through the City of Saint John and Rockwood Park instead of a marine crossing of Saint John Harbour. However, the Board finds that EBPC was able to demonstrate that its corridor evaluation and selection approach was reasonable, objective, and appropriate with regard to its Project purpose and the interests of those affected. By minimizing overall length and by using existing linear developments and other disturbed lands to the extent possible, including the crossing of Rockwood Park via the existing power line RoW, EBPC has selected a route that, compared to other onshore alternatives, minimizes adverse impacts to the land, landowners, and other residents in surrounding areas.

The Board considers the widths proposed for the urban and rural portions of the preferred corridor, within which the detailed route of the pipeline RoW would be determined, to be acceptable. The Board finds EBPC's proposal for a narrower urban portion of the preferred corridor, in order to minimize impact on local surroundings during detailed route siting, to be reasonable and justified given the more developed nature of these lands compared to the rural portion of the corridor. The Board is also satisfied with EBPC's proposed widening of the preferred corridor at specific locations, to provide greater detailed routing flexibility to avoid or minimize impacts to landowners.

The Board finds that EBPC's consultation with landowners and other stakeholders regarding corridor selection and design meets the basic requirements for such an undertaking. EBPC held open houses and used the feedback from these open houses to make a final determination on its preferred corridor. The Board notes that EBPC undertook to identify and notify all landowners within its preferred corridor to the extent that contact information could be obtained from a provincial government public website, and that it has applied a system for ongoing landowner engagement and issues tracking to guide and influence Project design and implementation. The Board recognizes the proposed modifications made by EBPC to the width and location of its preferred corridor in response to issues identified by potentially affected landowners and other stakeholders, and finds these adjustments to be appropriate and acceptable. Further discussion of EBPC's consultation as a whole is contained in Chapter 5 of these Reasons.

The Board notes that EBPC has obtained Project support or non-objection from a number of landowners or RoW holders within the preferred corridor. This includes the co-stewards of Rockwood Park - the City of Saint John and the Saint John Horticultural Association - as well as NB Power, which holds RoWs along approximately one-quarter of the proposed corridor. The Board finds that EBPC's preferred corridor selection process was appropriate.

6.3.2 General Land Requirements

266 EBPC stated that a 30 m-wide easement would typically be obtained for the proposed pipeline RoW, and that the easement would be for one natural gas pipeline, with no provision for additional pipelines or infrastructure. EBPC noted that preliminary investigation indicated that approximately 319 different properties would be crossed and therefore permanently affected by the proposed pipeline easement. EBPC submitted that additional permanent lands would be required for six valve sites, a combined meter station and launcher site, and a combined valve and launcher/receiver site. Each valve site would be approximately 20 m x 20 m, the combined valve and launcher/receiver site would be approximately 30 m x 100 m, and the combined meter station and launcher site would be approximately 50 m x 50 m.

267 EBPC noted that lands would be required for permanent access roads for the valve, meter station, and launcher/receiver sites. However, EBPC stated that all valve sites would be accessible from existing roads. Depending on the final location of the meter station, a permanent access road along the pipeline easement or a short driveway from an existing road may be required.

268 EBPC noted that temporary working room (TWR) would be required where the proposed easement area would not be sufficient for construction needs, such as at stream, road, and other crossings. Anticipated typical TWR size for watercourse crossings would be 60 m x 10 m, and 50 m x 10 m for road crossings, at all four corners of each crossing, unless constrained by existing physical features. In addition to TWR, lands for marshalling yards, storage areas, and access roads to the RoW would be required on a temporary basis during construction. EBPC stated that two to three marshalling yards would be established, in proximity to populated centres and close to transportation infrastructure and utilities.

Views of Interested Parties

269 Questions were raised by parties about the need for a 30 m-wide easement and the efforts taken by EBPC to minimize the Project footprint, including the possibility of a narrower easement.

270 Environment Canada indicated that using existing linear corridors, such as the SJL pipeline and the NB Power IPL RoWs, could reduce environmental impacts.

EBPC's Response to Concerns Raised

271 EBPC submitted that 30 m for an easement width had been chosen on the basis of minimizing disturbance while providing sufficient space for efficient and safe construction and operation. However, EBPC stated that it would be willing to consider variations from the standard width on a site-specific basis, if requested by the landowner and if construction and operation would not be compromised. EBPC also noted that its choice of a 30 m-wide easement was based primarily on the experience gained from M&NP's 1999 mainline construction through similarly forested terrain, where difficulties were encountered in building a 30-inch pipeline in a 25 m-wide easement.

272 EBPC stated that it was giving serious consideration to requests from some landowners and stakeholders to limit its permanent easement width in rural areas to 25 m, with an additional 5 m taken as TWR only during construction. EBPC submitted that 30 m was still considered necessary for the urban portion, as it would provide additional protection from encroachments, although adjustments would still be considered upon landowner request, as long as safe construction and operation were not compromised.

273 EBPC noted that it is investigating numerous options to minimize land requirements, most importantly the ability to overlap other existing RoWs for power transmission lines, the SJL pipeline, and the NB Power IPL currently under construction, thus reducing the need for a full 30 m-wide easement footprint in all areas. EBPC asserted that the objective of minimizing the Project footprint was a key consideration in its selection of a preferred corridor.

274 EBPC stated that it was striving to maximize the amount of easement overlap with NB Power's RoWs, including a commitment to overlap NB Power easements through Rockwood Park to the extent feasible. EBPC indicated that it was pursuing an approximately 11 m overlap with the existing power line RoW in Rockwood Park. According to EBPC, CSA setback requirements would generally result in approximately 10 to 12 m of maximum overlap with the existing SJL pipeline RoW. EBPC stated that it would also make efforts to utilize existing NB Power and SJL pipeline easements for its TWR requirements, where possible.

275 Besides the lands required for easement, TWR, and above-ground facilities such as the valve sites and the meter station, EBPC stated that it would acquire the minimum amount of additional lands to complete the Project successfully.

Views of the Board

The Board recognizes that a large number of properties and their landowners would be directly affected by the footprint required for the Brunswick Pipeline Project. However, in considering the potential impacts of the Project on landowners, the Board finds that EBPC's anticipated permanent and temporary land requirements are reasonable and justified, given the information on the record. The Board is of the view that EBPC has adequately demonstrated the need for a 30 m-wide easement and the additional lands required for above-ground facilities and temporary uses in order to construct and operate the pipeline in a safe and efficient manner. The Board acknowledges EBPC's submission that all temporary and permanent access requirements would be provided by existing roads and the proposed pipeline easement, except for new land that may be permanently required for a short driveway to connect an existing road with the proposed meter station. The Board recognizes EBPC's efforts to minimize any new permanent and temporary Project footprint by utilizing existing RoWs and other disturbed lands to the extent possible, and by considering site-specific landowner requests to reduce easement width where feasible.

The Board notes that using existing linear corridors, where appropriate, tends to reduce environmental impacts. The Board finds that EBPC has maximized the use of existing RoWs. Based on the application of the principle of minimal land disturbance combined with the rigours of the overall route selection process, the Board finds that the lands required for the Brunswick Pipeline Project are reasonable and appropriate.

6.3.3 Land Acquisition

276 EBPC stated that the proposed Brunswick Pipeline and ancillary facilities would generally require negotiation and acquisition of easements for the pipeline RoW, fee simple title for above-ground facilities such as valve sites and the meter station, permanent and temporary access rights over existing roads and potentially for a new driveway to access the meter station, and temporary rights for TWR, marshalling yards, and storage areas during construction. These lands rights would need to be acquired from private, Crown, corporate, and municipal landowners, with private landowners concentrated within the City of Saint John, particularly in the areas of Red Head, Milford, Westmorland Road, Spar Cove Road, Millidge Avenue, and Manawagonish Road. EBPC indicated that the City of Saint John owns 21 properties, including Rockwood Park, that may be directly affected by the pipeline route.

277 EBPC stated that its goal was to reach an amicable agreement for easement rights from all affected landowners. EBPC filed sample forms of notice to demonstrate compliance with s. 87 of the NEB Act. EBPC indicated that land acquisition agreements and other documents would be consistent with those previously filed by M&NP, and that sample copies of land acquisition agreements, to demonstrate compliance with s. 86 of the NEB Act, would be filed with the Board once finalized.

278 EBPC referred to a Letter of Commitments (LOC), originally developed for the M&NP Mainline project in 1997, which EBPC had updated and adopted for the Brunswick Pipeline Project. EBPC stated that the LOC establishes a common framework for dealing with landowners affected by its pipeline Project in a consistent manner that is fair to both parties on such matters as land acquisition negotiations, construction, and complaints. EBPC submitted that the LOC represents additional undertakings to ensure landowners' rights would be considered and protected.

279 EBPC stated that, since June 2005, it has been implementing a landowner contact and land rights acquisition program that includes:

* identifying all landowners within the preferred corridor for contact by RoW representatives to advise them of the Project, seek permission for field survey access, and answer any questions;
* successfully signing access permits with 89 percent of all landowners contacted as of November 2006, to allow EBPC to enter their lands to conduct further routing, environmental, archaeological, and constructability studies;
* specific consultation undertaken with, and pre-construction reports prepared for, all landowners found to be directly affected by the preliminary detailed pipeline route, to learn more about specific property features and each landowner's existing and planned property uses in order to find potential compatibilities in detailed route siting;
* capturing special requests made by these landowners so that they may be entered into a construction line list, to aid ongoing working relationships with affected landowners throughout the Project lifecycle;
* commencing service of s. 87 notices and land acquisition negotiations with landowners directly affected by the preliminary detailed route; and
* assignment of RoW agents to attend on landowners and to be their primary points of contact for all Project-related questions, issues, and concerns once construction commences.

Views of Interested Parties

280 A number of concerns were raised by parties about the nature and extent of the land rights to be acquired for the Brunswick Pipeline Project and the impact that these land rights would have on the ability of landowners to use their properties for such purposes as gardening, farming, and future development.

EBPC's Response to Concerns Raised

281 EBPC stated that for the pipeline RoW, it would generally be acquiring an easement, allowing it to construct, operate, and maintain the pipeline, whereby landowners would retain title over the easement lands, with restrictions. EBPC submitted that it would compensate the landowner for the value of the easement lands and for damages incurred, depending on existing and perhaps future uses of the land.

282 EBPC suggested that, although restrictions would be imposed on a landowner's property where it is crossed by an easement, it does not necessarily pose a serious obstacle to future development, and there may be specific instances where EBPC could work with the landowner to try to mitigate these impacts. EBPC also stated that generally it would only acquire outright ownership (i.e., fee simple title) of those lands required for above-ground facilities, such as the valve sites and meter station.

Views of the Board

The Board has considered EBPC's land acquisition approach for the Brunswick Pipeline Project and finds it to be appropriate. The Board recognizes EBPC's commitments to comply with the land acquisition requirements of the NEB Act, the principles of which are reflected in its LOC. The Board notes that EBPC is implementing systems for recording, tracking, and addressing landowner concerns in its land acquisition approach, and that EBPC indicates a willingness to work with landowners to address site-specific land-use interests in its pipeline easements and other land agreements. Although the Brunswick Pipeline Project would directly affect many landowners, the Board finds that with these commitments, EBPC has demonstrated that it will be respectful of landowner rights and concerns should the application be approved.

The Board recognizes that some landowners have indicated their opposition to the Brunswick Pipeline passing through their properties, and that some of this opposition is based on past experiences with pipelines on their lands. Because of the commitments made by EBPC with regard to land acquisition, and because its preferred corridor is at least 100 m-wide, thus providing some flexibility in the siting of its 30-m wide pipeline easement, the Board finds that EBPC is committed to address these concerns.

The Board notes that the NEB Act includes provisions pertaining to compensation as they relate to land acquisition for the purposes of a pipeline. Under the NEB Act, matters of compensation are considered by, and negotiation or arbitration processes are available through, the Minister of Natural Resources Canada.

Chapter 7

Tolls and Tariffs and Financial Matters

7.1 Tolls and Tariffs

283 As mentioned in Chapter 1, EBPC and Repsol, the only shipper on the Brunswick Pipeline, have reached a negotiated toll agreement dated 15 May 2006. This agreement obligates Repsol to pay a monthly fixed toll for the transportation of 791 292 GJ/d on the Brunswick Pipeline over a 25-year period. The 791 292 GJ/d is the Maximum Daily Transportation Quantity (MDTQ) specified in the FSA between EBPC and Repsol. The monthly fixed toll would cover all fixed charges applicable to the Brunswick Pipeline, including an equity return, typically in the 11 to 14 percent range. Repsol would have to pay the monthly fixed toll notwithstanding the actual level of throughput in any given month. Repsol's parent company, Repsol YPF, an investment grade company, has guaranteed Repsol's obligations under the negotiated toll agreement.

284 The monthly toll provided in the negotiated toll agreement may change if the final capital cost of the Brunswick Pipeline falls outside a determined range. At the request of NSDOE, EPBC has agreed to publicly file the final capital cost of the Project so that the final toll to be paid by Repsol is known.

285 Even though Repsol has committed to use the majority of the capacity, EBPC confirmed that there are three options for third parties seeking service on the Brunswick Pipeline. It would be possible for third parties to negotiate with EBPC for capacity not required by Repsol (capacity over the MDTQ); to negotiate with Repsol for an assignment of its unused capacity; or to negotiate with EBPC for an expansion of the Brunswick Pipeline. EBPC noted that should any potential shipper be unable to reach an agreement with EBPC over the applicable tolls or terms of service, it would have the right to have the Board adjudicate the matter.

286 In response to concerns expressed by EGNB related to the possibility of accessing the Brunswick Pipeline, EBPC indicated that it is willing to allow EGNB to design, permit, construct, own, operate and maintain any interconnecting custody transfer station(s) that connect to the Brunswick Pipeline. Furthermore, EBPC confirmed that it will not require EGNB to provide proof of gas supply when interconnecting with the Brunswick Pipeline. In order to implement this commitment, EBPC confirmed that it will, within four months of receipt of a Certificate pursuant to its application, develop in consultation with EGNB, appropriate terms and conditions related to pipeline operational matters. EBPC noted that such terms and conditions would only apply to EGNB and that different tolls and tariffs could apply to different shippers.

Views of Interested Parties

287 EGNB stated that it was the only participant in this proceeding who operated a local distribution company that may have the opportunity to interconnect directly with the Brunswick Pipeline. As such, it was satisfied with EBPC's evidence related to pipeline access matters. If the Board were to issue a Certificate to EBPC, EGNB asked the Board to confirm EBPC's requirement to fulfill these commitments in its decision.

288 Imperial stated that it considered the toll agreement between EBPC and Repsol as a negotiated settlement and took no exception to approval of the applied-for toll between EBPC and Repsol. Imperial noted that the sole reason for its support for the Brunswick Pipeline was to secure its ability to turn back capacity on the M&NP US system.

289 M&NP supported the timely approval of the Brunswick Pipeline Project as it would bring an additional, secure and reliable source of supply to the Maritimes that could be transported to the Maritime Canada markets by means of the M&NP system. M&NP noted that this incremental supply source is important for the continued growth and development of the natural gas markets in the Maritimes.

290 Repsol submitted that transportation costs on the Brunswick Pipeline from the Canaport[TM] LNG Terminal to the Northeast US were critical both in order to compete in the anchor market and to attract supply. Repsol succeeded in obtaining from M&NP a *conditional* market response that Repsol subsequently terminated because M&NP could not satisfy Repsol's condition pertaining to a long-term negotiated toll. Subsequently, Repsol succeeded in obtaining an *unconditional* market response to its particular service needs from EBPC. The negotiated toll agreement was one of the outcomes of this market response. Repsol submitted that this monthly fixed toll is just and reasonable since the amounts to be paid cover all costs associated with the Brunswick Pipeline and are acceptable to both the shipper and the pipeline owner. Repsol asked the Board to approve the monthly fixed toll payable by Repsol to EBPC over the entire term of the negotiated toll agreement.

291 NSDOE noted that even if the Brunswick Pipeline would have no impact on the tolls of the M&NP Canada line, these tolls would be rendered less competitive as a result of the lower tolls on the Brunswick Pipeline. NSDOE argued that the postage stamp toll on M&NP Canada was designed to facilitate the development of the natural gas market in the Maritimes and that, if it is not competitive, development in the Maritimes may suffer. NSDOE was also concerned that, in a world where tolls and tariffs are negotiated on a case-by-case basis, tolls charged to different parties under substantially similar circumstances may not be equal. To mitigate this issue, NSDOE submitted that all tolls and tariffs that may be developed between EBPC and Repsol, or any other shipper on the Brunswick Pipeline, should be filed with the Board and be made publicly available. Further, NSDOE submitted that EBPC should be directed by the Board to establish a tolls and tariffs working group composed of interested parties or stakeholders, including NSDOE.

Views of the Board

Given that EBPC and Repsol, the sole shipper on the Brunswick Pipeline, have reached a negotiated toll agreement, which obligates Repsol to pay tolls that cover all fixed charges of the pipeline and an adequate equity return over a 25-year period, the Board finds that the tolls provided in the negotiated toll agreement are just and reasonable.

The Board expects EBPC to file the final capital cost of the Brunswick Pipeline. If the final capital cost is outside the range specified in the negotiated toll agreement, the Board directs EBPC to file an "adjusted" section 2.1 of the negotiated toll agreement.

In the Board's view, the Brunswick Pipeline is an open access pipeline. The Board is satisfied with the commitment of EBPC to enter into negotiations with EGNB to reach a mutually-acceptable agreement on pipeline access matters. The Board expects EBPC to honour this commitment within the timeline specified in its evidence. Furthermore, the Board expects EBPC to file the agreement pursuant to section 60 of the NEB Act. If EBPC and EGNB cannot reach an agreement, the matter could be brought to the Board for adjudication.

The Board is of the view that two or more shippers could use the Brunswick Pipeline under different circumstances; for example, they could have different transportation distances, different contract terms, or different types of services. As such, the Board recognizes that different shippers could face different tolls on the Brunswick Pipeline. However, tolls to be paid by third parties on the Brunswick Pipeline would have to be filed, or approved, by the Board before they could be charged.

The decision to establish tolls and tariffs working groups is usually left to the discretion of each pipeline and its shippers based on a desire to discuss and possibly resolve issues outside of the Board's processes. The Board finds that there was no evidence introduced that articulated a compelling need to require the establishment of such a working group for the Brunswick Pipeline at this time.

With regard to potential commercial burdens created by the Brunswick Pipeline, the Board recognizes that there is a significant difference on a per GJ basis between the tolls on the Brunswick Pipeline and the M&NP Canada system. However, the Board notes that there is no evidence on the record that shows that protecting the M&NP Canada system and its shippers from competition would serve the Maritime market in more efficient manner than in letting it operate on its own. In fact, the shippers on M&NP Canada either supported the project or did not oppose it.

In conclusion, the Board finds that the tolls to be charged under the negotiated toll agreement between EBPC and Repsol are just and reasonable and that there is no unjust discrimination in tolls, services or facilities against any person or locality. The Board approves the tolls to be charged by EBPC to Repsol.

7.2 Anadarko's Evidence (Bypass Issues)

292 Anadarko submitted that the Brunswick Pipeline would be a bypass of the Canadian M&NP system because it would duplicate facilities that could readily be made capable of providing a similar service to that proposed by the Brunswick Pipeline. According to Anadarko, the Canadian and US M&NP systems are indivisible and the Brunswick Pipeline would be a parasitic bypass since it would tap into the economies of scale and absorb virtually all of the existing and readily expandable capacity on the US segment of the M&NP system. Anadarko submitted that despite the fact that the Brunswick Pipeline would be both physically and operationally dependent upon the integrated M&NP system, it proposes to pay nothing for it or towards it. Contrary to EBPC's claim, Anadarko stated that the Brunswick Pipeline could not and would not be a stand-alone pipeline.

293 Anadarko stated that, since the Brunswick Pipeline does not pay its fair share of the costs associated with the utilization on the M&NP Mainline, Anadarko's LNG supply acquisition efforts were hampered by having to try to overcome the competing Canaport[TM] Project's transportation advantage gained by the Brunswick Pipeline.

294 Anadarko submitted that if the Brunswick Pipeline were to be approved, it would not be the market that would be deciding what, if any, toll advantage the Canaport[TM] Project has over the Bear Head Project; it would be the NEB. Anadarko was of the view that there is no justification for giving any toll advantage whatsoever to the Canaport[TM] Project over the Bear Head Project.

295 Mr. Peter Milne, Anadarko's expert witness, was of the view that neither the Canadian segment of the M&NP system nor the US segment could exist or operate independently of the other segment. As such, the Brunswick Pipeline proposal would be a typical bypass pipeline that is designed specifically to avoid the postage stamp toll on the Canadian segment of the M&NP system. Furthermore, Mr. Milne submitted that if it is not commercially feasible to construct and operate a stand-alone or independent pipeline from Canaport to Dracut, Massachusetts and it is only feasible to provide service to Repsol by utilizing the M&NP US system, then the cost to provide service from the point where the Repsol gas would join the M&NP US system is dependent on the cost of the integrated M&NP system. In his view, the shipper on the Brunswick Pipeline should then bear an appropriate share of the cost of the system.

296 Mr. Milne also submitted that the cost of gas from Canaport delivered to Nova Scotia or NB (not via an interconnection) would be considerably higher if the Brunswick Pipeline bypasses the Canadian segment of the M&NP system, undermining the development of Canadian Maritime markets. From a public interest perspective, there are no economic efficiencies created by allowing the proposed Brunswick Pipeline to bypass the Canadian segment of the M&NP system.

297 Anadarko requested that the Brunswick Pipeline application be denied because it is an inefficient, unfair and inequitable bypass of the M&NP system. In denying the application, Mr. Milne suggested that the NEB should also urge M&NP to conduct a new open season for capacity on its system. Anadarko further submitted that if the Board were to approve the Brunswick Pipeline and its associated toll, the Board should urge M&NP to enter into negotiations with the Bear Head Project under a tolling structure that would be based on incremental rates so that this project could compete fairly with the Canaport[TM] Project.

Views of EBPC and Repsol

298 EBPC recognized that the Brunswick Pipeline is dependent on the US segment of M&NP and that this segment is dependent on the Canadian M&NP system. However, EBPC was of the view that Anadarko's theory of dependency lacked merit and should be rejected. If this theory of dependency were to be true, no separate pipeline or separately-owned pipeline system connecting with another could be described as a stand-alone system. The Great Lakes Gas Transmission System could not be described as a pipeline that stands alone from TransCanada PipeLines Limited (TransCanada). Vector could not be described as standing alone from Alliance Pipeline Ltd. Union Gas Limited and Enbridge Gas Distribution Inc. could not be described as standing alone from TransCanada or other upstream connecting pipelines. According to EBPC, the Brunswick Pipeline is a stand-alone system. It is not integrated with the system owned and operated by M&NP in Canada.

299 Repsol submitted that confining the scope of the alternatives to be considered to a cross-border stand-alone pipeline was a business decision. Repsol needed a transportation agreement that would enable the Canaport[TM] LNG Terminal to operate as a viable supply source. EBPC further submitted that the stand-alone nature of the Brunswick Pipeline was a prerequisite to its realization. It is a market-based pipeline supported by a chain of commercial arrangements.

300 EBPC and Repsol were of the view that the Brunswick Pipeline would not duplicate existing facilities. That conclusion is reinforced by the fact that the Brunswick Pipeline will provide transportation from an incremental supply source. It is then not reasonable to refer to the Brunswick Pipeline as a "bypass" pipeline. EBPC submitted that the label one uses to describe the Brunswick Pipeline is of little relevance; the issue for the Board is to determine if the Brunswick Pipeline is in the overall public interest.

301 In EBPC and Repsol's view, Anadarko's position was without merit and the Board should reject any submissions for denial of the application made by Anadarko, which is a speculative competitor of the Canaport[TM] LNG Terminal.

Views of the Board

In providing its 17 November 2006 ruling on an objection raised to a line of questions Anadarko was pursuing with EBPC's witness, the Board provided a framework for consideration of relevant issues in this proceeding. This ruling is attached in Appendix VI. In accordance with the framework set out in the ruling, the Board is of the view that the status of the Bear Head Project, its relation with M&NP, and whether the Bear

Head Project should be granted any special treatment by M&NP are beyond the scope of this proceeding. If Anadarko wishes to raise an issue with respect to the tolls on the M&NP system, it may file the appropriate application with the Board; this proceeding is not the appropriate forum to consider such issues.

In light of the Board's ruling, certain sections of Mr. Milne's evidence outlining an expansion of the SJL and estimating the costs and potential savings of such an option are, in the Board's view, outside the scope of this proceeding either under the CEA Act, as noted in the NEB EA Report attached as Appendix VII to these Reasons, or under the NEB Act. There is no evidence that any such expansion could or would be undertaken by the owner of the system, M&NP. Based on the evidence before the Board, this is not a currently planned expansion, nor even a reasonably contemplated one. The Board notes that M&NP, and a number of its shippers, such as Imperial Oil Resources, ExxonMobil Canada Ltd., and Shell Canada Limited, were parties to this proceeding and did not oppose this Project; in fact, M&NP, Imperial Oil Resources and ExxonMobil Canada Ltd. supported it. To enter into a speculative exercise comparing the Brunswick Pipeline tolls to tolls that may result on a different system if a hypothetical expansion were to occur, when there is no evidence that the owner would undertake such expansion, or that the current shippers desire or would even use the expanded facilities, is not sufficiently probative to the Board's decision on whether the Brunswick Pipeline is in the present and future public convenience and necessity. Such an exercise also does not factor into the Board's determination of whether the tolls to be charged on the Brunswick Pipeline are just and reasonable, and not unjustly discriminatory.

With respect to Anadarko's claim that the Brunswick Pipeline is a "bypass" pipeline, the Board is of the view that for the Project to qualify as a bypass, there would have to be *existing* facilities that perform the same functions as the proposed Project, which the proposed Project proposed to circumvent. As noted in the EA, the Board accepted EBPC's evidence that reversing the SJL would not be a technically feasible alternative to the Project. There are no existing facilities capable of providing the same service as the proposed Brunswick Pipeline. In the Board's view, the Brunswick Pipeline is not a bypass pipeline. Even if the Brunswick Pipeline could be considered a "bypass" pipeline, that classification in and of itself is not determinative; the Board still has to determine whether the Brunswick Pipeline is in the present and future public convenience and necessity.

The Board is satisfied, on the basis of the evidence submitted, that the Brunswick Pipeline would be a stand-alone pipeline for the following reasons. First, it is owned by a different corporate entity than the M&NP system and is therefore legally distinguishable. Second, its facilities are physically separate or distinguishable from the existing M&NP facilities. Third, it would provide a unique and separate service from any other service already provided by the M&NP system, and therefore is functionally distinguishable from M&NP.

Furthermore, the Board is not persuaded that the mere fact that it connects to the M&NP US system defeats the claim that the Brunswick Pipeline is a stand-alone pipeline; due to the integrated nature of the natural gas market infrastructure of North America, it would be possible to argue that almost every pipeline depends on another one.

The Board recognizes that the Brunswick Pipeline may give a transportation advantage to the Canaport[TM] LNG Terminal compared to the Bear

Head project, should the Bear Head project be constructed, ship volumes on the M&NP system and not receive a special toll for such shipments. However, the Board's mandate is neither to protect parties from competition nor to protect specific private interests. The Board believes that the public interest is best served by allowing competitive forces to work, unless there is clear evidence of significant market dysfunction. In the context of this proceeding, the Board does not see any clear evidence of significant market dysfunction.

7.3 Method of Regulation

302 EBPC requested that the Board issue an Order designating it as a Group 2 company for the purposes of toll and tariff regulation. EBPC submitted that its request is consistent with the goal of the Brunswick Pipeline and its only shipper, Repsol, to minimize the need for regulatory litigation and gives effect to the commercial arrangements of the parties. Further, EBPC submitted that the Brunswick Pipeline is not of a size or complexity that warrants the more extensive regulation appropriate for major Group 1 transmission companies. In accordance with Group 2 requirements, EBPC stated that it would maintain separate books of account in Canada.

303 NSDOE suggested that if the Board were to grant the Group 2 status to EBPC, it should establish terms providing for the ongoing monitoring and, perhaps, auditing of tolling arrangements established by EBPC to ensure that they are fair and non-discriminatory. This approach would be more than a passive complaint-based process.

Views of the Board

The Board is of the view that granting Group 2 status to the Brunswick Pipeline for toll and tariff regulation is appropriate given the size of its facilities and the fact that it has only one shipper at this time. EBPC is required to maintain separate books of account in accordance with generally-accepted accounting principles and to file audited financial statements within 120 days after the end of each fiscal year.

The Board does not see the need to monitor or audit the Brunswick Pipeline in a more proactive way than what is currently done for other Group 2 companies. Within the Group 2 framework, any existing or potential third party shipper with a legitimate complaint against EBPC can bring the matter to the Board for adjudication.

The Board grants Group 2 status to the Brunswick Pipeline for the purposes of toll and tariff regulation.

7.4 Project Financing and Economic Feasibility

304 EBPC submitted that the total capital cost of the Brunswick Pipeline is estimated to be approximately $350 million. The Brunswick Pipeline would be financed by Emera Inc., EBPC's parent company, through a combination of debt and equity. In order to finance the Project, Emera Inc. has access to public debt and equity markets, including a $550 million credit facility provided by its banking syndicate.

305 EBPC and Repsol both submitted that the commercial agreements, guaranteed by their respective parent companies and discussed in section 7.1, are the foundation of the proposed Brunswick Pipeline. Those agreements are designed to ensure that the Brunswick Pipeline will be economically feasible. For the first 25 years of its operation, Repsol will be at risk for the costs associated with the Project. Repsol will pay all pre-approval and pre-construction costs and will pay the entire fixed costs of the pipeline for the first 25 years of its operation, regardless of throughput. As a result, the Brunswick Pipeline is a commercially "at risk" pipeline.

> ***Views of the Board***
>
> The Board is of the view that the financing of the Brunswick Pipeline Project is adequate.
>
> In assessing the economic feasibility of a project, the Board usually considers whether the tolls on the proposed pipeline are likely to be paid and whether the proposed pipeline is likely to be used at a reasonable level over its economic life.
>
> With regard to the first test, the Board finds the assumption that the Brunswick Pipeline has its foundations in the commercial agreements between EBPC and Repsol to be acceptable. Consequently, the Board finds it reasonable to assume that the tolls will be paid by Repsol to EBPC over the first 25 years of the operation of the pipeline. As for the second test, given the significant financial commitments made by Repsol to the Brunswick Pipeline, the Board is of the view that Repsol has sufficient economic incentives to use the Pipeline at a reasonable level over its economic life. Therefore, the Board finds that the Brunswick Pipeline is economically feasible.

Chapter 8

The Board's Public Interest Determination

8.1 The Public Interest

306 As noted in Chapter 2 of these Reasons for Decision, the Board has described the public interest in the following terms:

> The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision.

307 When applying the "present and future public convenience and necessity" test under Part III of the NEB Act, the Board makes a determination in the overall "public interest". In its consideration of an application, the Board is required to identify and weigh all relevant evidence on the record and come to a determination whether, overall, the project is in the public interest or in the present and future public convenience and necessity. This requires that the Board balance the benefits and the burdens of the project, based upon analysis of the relevant evidence properly before the Board, to come to its final determination.

308 This Chapter provides the Board's assessment of the overall benefits and burdens of the Brunswick Pipeline Project in relation to its decision under s. 52, Part III of the NEB Act.

8.2 Benefits and Burdens of the Project

309 Tables 8-1 and 8-2 summarize the key benefits and burdens, respectively, of the proposed Project that were determined by the Board and outlined in the previous chapters of these Reasons and in the EA. Both tables indicate whether the benefits or burdens would apply locally (i.e., within the immediate vicinity of the Project, such as the City of Saint John), regionally (i.e., within the Maritimes) or nationally.

Table 8-1

Summary of Key Benefits

* **Benefits**: Maritime Canada access to new secure natural gas supply source (up to 250,000 MMBtu/day) from a well-known global supplier.

  Type of Impacts: Local, Regional, National.

* **Benefits**: Regional incremental natural gas supply source that will enable Maritime Canada to fulfill current and anticipated future natural gas needs by promoting the long-term growth of the regional energy market.

  Type of Impacts: Local, Regional, National.

* **Benefits**: Open and competitive markets within Maritime Canada will be encouraged through the increased development of competitive regional markets for natural gas.

  Type of Impacts: Local, Regional.

* **Benefits**: Introduction of an incremental source of natural gas supply to the region could decrease potential short-term price volatility and facilitate long-term price stability for the region

  Type of Impacts: Local, Regional, National.

* **Benefits**: Increased utilization of current Maritime energy infrastructure through accessibility to an incremental reliable supply source. For example, M&NP shippers can mitigate demand charges by utilizing existing delivery points as receipt points for the Repsol gas supplies and then utilizing their existing Canadian capacity to exchange or backhaul the gas to where it might be actually consumed or possibly resold.

  Type of Impacts: Local, Regional, Natioal.

* **Benefits**: Flexibility to draw supply from various fields and therefore ability to mitigate potential supply problems in any given supply basin.

  Type of Impacts: Regional, National.

* **Benefits**: EBPC's commitment to provide training and funding to first responders.

  Type of Impacts: Local, Regional.

* **Benefits**: Potential for increased use of natural gas over other less clean burning fuels such as coal and oil.

  Type of Impacts: Local, Regional, National.

* **Benefits**: Aboriginal "set-aside" that would target two percent of all third-party contracted services for NB Mi'kmaq and Maliseet businesses.

  Type of Impacts: Regional.

* **Benefits**: Project is expected to create direct, indirect and induced employment and income for the City of Saint John and the region, for example:

  * by allowing local and regional workers and businesses to better compete, and be successful, in their bids on tenders for labour and materials;
  * direct incremental jobs in Saint John area [during construction total direct employment of approx. 373 person years; during operation - four full time equivalent positions on pipeline]; and
  * during construction - $137 million in GDP for New Brunswick and $210 million for rest of Canada. During operation - GDP impact of $2 million for province and $2 million for rest of

Canada. Annual gross economic impact $4 million for province, $5 million for rest of Canada.

Type of Impacts: Local, Regional, National.

* **Benefits**: Enabling M&NP shippers to turn back capacity on the M&NP US system, relieving those shippers of demand charge obligations

  Type of Impacts: Regional.

* **Benefits**: Pipeline would contribute tax revenues to various levels of government, estimated at $3.3 million (property), $2 million (federal), $1 million (provincial), and $1 million (capital tax) for a total of $7.3 million annually. (Approx. $700, 000 property taxes to City of Saint John)

Type of Impacts: Local, Regional, National.

Table 8-2

Summary of Key Burdens

* **Burdens**: Concerns about access to communities in the event of an emergency and the capacity of first responders to handle an emergency.

  Type of Impacts: Local.

* **Burdens**: Potential for accidents or malfunctions associated with the pipeline and concerns about resulting impacts on local population.

  Type of Impacts: Local.

* **Burden**: Potential for and concerns about blast vibration damage to structures and the environment.

  Type of Impacts: Local.

* **Burdens**: Concerns about increased noise and vibration, and the duration of construction, especially for residents of Pokiok and Milford, associated with the HDD under Saint John River.

  Type of Impacts: Local.

* **Burdens**: Disruption and loss of landowners' use, enjoyment, and opportunities for development of their properties.

Type of Impacts: Local.

* **Burdens**: Potential adverse environmental effects on biophysical (e.g., effects to vegetation, wildlife and surface water) and socio-economic (e.g., disruption of recreational pursuits) components of Rockwood Park.

  Type of Impacts: Local.

* **Burdens**: Key potential adverse environmental effects on the biophysical environment along the pipeline RoW include effects on Species at Risk and Species of Conservation Concern, and on wetlands, as well as effects from unauthorized access to the RoW and acid rock drainage.

  Type of Impacts: Local, Regional, National.

* **Burdens**: Other potential environmental effects on the biophysical environment along the pipeline RoW include effects on soil and soil productivity, vegetation, water quality and quantity, fish and fish habitat, wildlife and wildlife habitat, and air quality.

  Type of Impacts: Local, Regional, National.

* **Burdens**: Potential issues may arise when underground infrastructure is located in close proximity to a pipeline.

  Type of Impacts: Local.

* **Burdens**: Key potential adverse environmental effects on the socio-economic environment along the pipeline RoW include effects on heritage resources and on the current use of lands and resources for traditional purposes by Aboriginal persons.

  Type of Impacts: Local, Regional.

* **Burdens**: Other potential environmental effects on the socio-economic environment along the pipeline RoW include varying degrees of disruption, nuisance, and land-use impacts to landowners, residents, and commuters due to pipeline construction, operation, maintenance, and RoW restrictions

  Type of Impacts: Local, Regional.

* **Burdens**: Low tolls on the Brunswick Pipeline could render the postage stamp toll on the M&NP Canada system less competitive.

Type of Impacts: Regional.

310 This is not intended to be a comprehensive list of all benefits and burdens mentioned during the proceeding by participants. Rather, it is a summary of the key benefits and burdens that the Board identified during its analysis of the evidence and ultimately weighed in reaching its decision. Both tables have been generally arranged from top to bottom in relative order of importance, as determined by the Board, during its deliberations and analysis of the evidence. A descriptive and more complete weighing of the benefits and burdens is found in Section 8.3.

8.3 Weighing of Benefits and Burdens

Benefits

311 The Board finds that the benefits associated with the Brunswick Pipeline bringing an additional and stable supply of gas into Maritime Canada are significant, real and numerous. Although some parties questioned whether access to the incremental supply source would be assured through potential direct connection, or whether the current M&NP infrastructure could be used to physically backhaul gas, the Board notes that there are a number of ways in which Maritime Canada could access the gas.

312 Access to the Project's natural gas supply could be achieved through the use of backhauls, swaps or direct connection to the Brunswick Pipeline. Given the number of potential methods this Project offers for accessing gas, the Board does not believe that some uncertainty or additional costs around one particular method substantially detracts from the considerable weight of the national, regional and local benefits potentially realized through access to a new incremental natural gas supply source.

313 For example, the Board finds that there would be a strong benefit to regional Canadian shippers, other than shippers on the Brunswick Pipeline, should this Project proceed. The Project will likely encourage increased utilization of current regional infrastructure, such as the M&NP system, through the potential accessibility to an incremental and reliable source of supply. Shippers on M&NP may mitigate their current demand charges by utilizing existing delivery points as receipt points for the Repsol gas supplies and then utilizing their existing Canadian capacity to swap or backhaul gas to where it might actually be consumed or possibly resold. There is an added national benefit to potentially utilizing unused capacity more efficiently on the M&NP system. The Board finds that the promotion of the efficient use of energy infrastructure is a strong benefit to all Canadians.

314 The Board finds that arguments that this gas may only be received by Irving Oil do not detract from the overall benefit of bringing an additional stable supply of gas to this region. From the evidence, it is understood that Irving Oil currently uses approximately 80 percent of the gas in Maritime Canada, and that it intends to use approximately 80,000 MMBtu/day of incremental gas from the new supply source. The Board finds that the viability of this new supply source is dependent upon the use of Brunswick Pipeline as a connection to a downstream anchor market since natural gas demand in the Maritimes is not independently substantial enough to attract investment in this supply source. Maritime

Canada gas usage in 2005, from the M&NP system, amounted to 80,000 MMBtu/day. Given that Irving Oil indicated in evidence that it would continue to honour its commitments on the M&NP Canada system, the logical conclusion is that this Project will result in, at a minimum, an incremental demand for gas of 80,000 MMBtu/day in the Maritimes.

315 Furthermore, even though Irving Oil is uncertain whether it will ship gas on the Brunswick Pipeline in excess of the amount that it intends to use proprietarily, the evidence indicates gas will also be accessible for use by the Maritime Canada market through various means, including through the Brunswick Pipeline. The Board is of the view that it is reasonable to conclude that Repsol and Irving Oil would seek to maximize the sale of gas into the Maritime Canada market, and that a local distribution company, like EGNB, could seek to interconnect with the Brunswick Pipeline to benefit from this new system.

316 There is an economic incentive for Repsol and Irving Oil to facilitate sales to the Maritime Canada market in that there would likely be lower transportation costs associated with delivery into this market than costs incurred if the gas were to be exported. In addition to a direct connection to the Brunswick Pipeline, other ways to access gas using the Project include swaps and backhauls. On this evidence, the Board finds that, on a balance of probabilities, the Maritimes will have access to this new natural gas source, and the Brunswick Pipeline will be instrumental in allowing the Maritimes to achieve the benefits associated with the addition of this incremental supply source.

317 The Board is of the view that Brunswick Pipeline's reliance on Repsol's portfolio of gas sources creates a considerable benefit in that it provides flexibility to draw supply from various fields. This flexibility mitigates potential supply problems in any specific basin and would provide regional and local Canadian shippers and users of this gas, such as local and regional utilities and businesses, with added assurance of supply. As a result, sourcing gas in this manner will likely encourage increased natural gas use and promote the long-term growth of the natural gas market both in the Maritimes and locally. Though there is no certainty with respect to how Repsol may manage its portfolio of assets, the Board is of the view that any uncertainty of this approach is sufficiently offset by the increased flexibility that reliance on a portfolio allows. In addition, given the investment Repsol and its affiliates have made in the area, as noted in Chapter 4, the Board is of the view that it is a logical conclusion that Repsol would seek to maximize return on its investments. Accordingly, the Board finds that there is a significant benefit associated with the supply of an additional, secure source of gas to the Maritimes. The Board also finds that the Brunswick Pipeline could provide a national benefit; for example, Repsol plans to pursue options to provide future natural gas service to Quebec markets using backhauls on existing pipeline systems.

318 Another key national, regional and local benefit found by the Board was the potential that the introduction of an incremental source of natural gas supply to the Maritimes could decrease potential short-term volatility and facilitate long-term price stability for the Region. Principles of supply and demand would indicate that increasing supply of a product to an area where supply is predicted to be tight has the potential to alleviate price volatility and put downward pressure on prices, which in turn could result in longer term price stabilization. The regional and local benefit of open and competitive markets within the Maritimes through the increased development of competitive regional markets for natural gas was given considerable weight by the Board. Both of these benefits provide an opportunity for the markets to work more efficiently, which is a benefit to all Canadians, but should specifically benefit residents of the Maritime Canada area.

319 The Board finds that a moderate benefit to the local and regional community would arise from EBPC's commitment to provide training and funding to first responders. While the primary purpose of this training and funding was described in terms of the ability of first responders to address an emergency arising from a pipeline incident, the Board finds that such additional training and funding will serve the local and regional communities by improving the capacity of first responders to address a broad variety of emergency situations.

320 The Board accepted EBPC's evidence that increased usage of natural gas could provide a potential environmental benefit to the Maritimes by reducing the region's dependence on less clean burning fuels such as coal and oil. However, the Board assigned this benefit limited weight given that realization of this benefit is likely dependent on other projects and activities outside the scope of this Project.

321 The Board noted and gave some weight to the evidence that Canadian shippers in the Maritimes may also receive a benefit from being able to turn back unused capacity on the M&NP US system, if the Brunswick Pipeline Project proceeds. This action would relieve them of their significant demand charge obligations on that system.

322 The Board finds that the Project would provide significant short-term direct incremental employment in the Saint John area, i.e., during construction there would be a total direct employment of approximately 373 person years (340 for construction of the urban portion of the pipeline, and 580 for the rural), plus supporting staff. The Board finds, however, that there could also be a burden associated with the creation of such a large number of short-term jobs within a relatively small population base; therefore, the Board has minimized the overall benefit that it attributed to the increase in short-term employment. The Board also notes that there would be few benefits in terms of jobs during operation, with only four full-time equivalent positions resulting from the Project. Therefore, the Board assigned only minimal weight to the benefit of direct incremental employment.

323 The Board notes EBPC's commitment to communicate labour and material requirements to labour unions and local suppliers in advance of tenders to allow the local worker and businesses time to prepare bids and adjust labour force and training requirements. This commitment could create an opportunity for local and regional workers and businesses by allowing them to better compete, and be successful, in their bids, further increasing the potential local economic benefits. If the proportional rates of indirect local and regional participation on this Project reach those experienced during the construction of the M&NP mainline (70 percent), the Board finds that this could be a moderate local and regional indirect benefit.

324 One specific regional benefit identified was EBPC's Aboriginal "set-aside", i.e., it would target two percent of all third-party contracted services for NB Mi'kmaq and Maliseet businesses. This regional benefit was assigned some weight by the Board.

325 There are regional and national benefits arising from this Project to which the Board assigned some weight. During construction, there would be $137 million in GDP for the province and $210 million for rest of Canada. During operation, the Project would have a GDP impact of $2 million for the province and $2 million for the rest of Canada. The annual gross economic impact is $4 million for the province and $5 million for the rest of Canada.

326 There were also local, regional and national benefits resulting from the tax revenues the pipeline would contribute to various levels of government. The revenues are estimated at $3.3 million in property tax, $2 million in federal tax, $1 million in provincial tax, and $1 million for capital tax. The total equates to $7.3 million annually. Approximately $700,000 of the property taxes would be distributed to the City of Saint John. Some weight was assigned to these benefits, although it is recognized that the property tax benefits to the City of Saint John may not be considered substantial if they stood alone.

Burdens

327 Most of the burdens identified in the previous Chapters of these Reasons and the key burdens identified in Table 8-2 are local in scope. This is often the case for linear fixed facilities.

328 A number of burdens were identified in the NEB EA report, attached as Appendix VII to these Reasons. Many of these burdens can be mitigated, and the Board assessed and weighed the likely success of potential mitigative options in reaching its determination, under the CEA Act, that the Project is not likely to have significant adverse environmental effects. Nevertheless, some impacts or burdens remain, and they must be considered and weighed in the Board's determination under Part III of the NEB Act.

329 Three key concerns identified during the proceeding were the risks of potential accidents and malfunctions of a high pressure pipeline, access to communities in the event of an emergency, and the capacity of first responders to handle this type of emergency. The Board finds that EBPC has mitigated the burdens related to these three fundamental public concerns to the Board's satisfaction and is satisfied that the Brunswick Pipeline could be constructed and operated in a safe manner. However, the perception by the public that these burdens have not been adequately addressed creates its own burden of stress and anxiety. As previously noted, EBPC could have gone much further in providing additional information with respect to these issues earlier in the process, which would have allowed a wider audience to have received this information, and to perhaps have been reassured.

330 As a result of EBPC not fully engaging the public as it could have, should the Project be approved, the Board would impose a number of conditions to alleviate this burden. For example, the Board would require the filing of a complete list of all commitments made and conditions imposed, the preparation of a public consultation program going forward, and the carrying out of a full emergency response exercise with the strong recommendation that it take place in the Milford area. Even with these conditions and the commitments EBPC has made, the Board has assigned this burden of stress and anxiety a high weight.

331 The potential for blast vibration damage to structures and the environment were burdens identified by the Board. EBPC's commitment to limit the vibrations (the PPV) near vibration-sensitive structures goes some way to mitigating this burden. Similarly, while the

Board determined that the adverse environmental effects relating to blasting were not likely to be significant, the potential for damage to the environment, for example, wetlands, should still be assessed as a burden. The Board notes EBPC's proposed mitigative strategies and its commitment, should damage occur to structures and the environment, to remedy or compensate for the damage. However, this does not, in and of itself, eliminate the burden, since there would likely be procedures and time required to remedy any damage. Accordingly, the Board has assigned some weight to this burden.

332 One of the potential adverse environmental effects on the socio-economic environment of the local residents identified is the effect from noise and vibration, particularly for those residents of Pokiok and Milford who will be near the HDD sites. While EBPC has committed to certain mitigation measures, it is clear that this burden will likely not be entirely mitigated. In addition, certain methods of mitigation may impose their own burdens; for example, relocating people if the noise is too disruptive requires that they leave their house for a period of time and must make adjustments to their day-to-day lives. As a result, this impact, while fairly short-term in the broad picture of the life of the Project, has been assigned moderate weight given its pervasive nature through a number of months.

333 The Brunswick Pipeline Project poses the potential in localized instances for disruption and loss of landowners' use, enjoyment, and opportunities for development of their properties, particularly for those who own or occupy the estimated 319 different properties that could be crossed by the pipeline RoW. However, the Board notes EBPC's preferred corridor design using existing RoWs and providing for greater pipeline routing flexibility where possible, its adopted Letter of Commitments for dealing with affected landowners in a fair and consistent manner, and its programs for working with potentially affected landowners to identify and address site-specific land-use interests in its detailed route design and pipeline land agreements where possible. Given these measures, the Board finds that there would be a small residual burden experienced by some landowners and occupants concentrated along the pipeline RoW.

334 The Board notes that the preferred corridor will follow an existing RoW through portions of Rockwood Park, which was described in evidence as a local and regional environmentally-sensitive landbase. Evidence was provided that many residents of Saint John use Rockwood Park for a broad variety of recreational pursuits and that there is much civic pride associated with the protection of this area. The Board notes that the proposed pipeline corridor traversing through a portion of Rockwood Park has drawn heavy criticism from public intervenors. The Board finds that EBPC's creation of an endowment fund for the Park could partially mitigate the burden associated with the land disturbance within the Park. The Board further finds that following an existing RoW through the Rockwood Park will substantively mitigate the potential biophysical burden associated with that portion of the proposed pipeline. However, the Board finds that a burden to the local and regional users of the Park remains, and therefore moderate weight was given.

335 Some burdens identified include potential adverse environmental effects on the biophysical environment along the proposed corridor, and involve effects on Species at Risk and Species of Conservation Concern, and wetlands, as well as effects from unauthorized access to the RoW and acid rock drainage. Other potential environmental effects include effects on soil and soil productivity, vegetation, water quality and quantity, fish and fish habitat, wildlife and wildlife habitat, and air quality. Given the mitigations EBPC has committed to, and the conditions the Board would impose should the application be approved, the Board has determined that it is unlikely that any significant adverse environmental effect would remain. Accordingly, low weight was attributed to any particular residual environmental burdens.

336 Although parties raised a potential burden of negative impacts to property values, specifically, as a result of accidents or malfunctions associated with the pipeline, the Board is of the view that this burden has little weight, particularly considering the multiple layers of protection EBPC has to ensure the safe operation of the pipeline, and as a result, the extremely low possibility of a major accident or malfunction. Furthermore, given the Board's acceptance of the conclusions of the de Stecher Study regarding the likelihood of negative impacts to property values, and its finding that any negative impacts on property value would be short-term and reversible, the Board has assigned this potential burden little weight.

337 Another issue identified was with respect to constructing and operating near underground infrastructure in close proximity to a pipeline. However, the Board notes EBPC's commitment to work with the City to achieve synergies, if possible, and with local developers and utilities to minimize disturbances. In addition, there is some flexibility in determining routing and depth of burial within the corridor to avoid potential impacts. Furthermore, the Board notes that St. Clair, to whom the construction and operation of the Pipeline has been contracted, has substantial relevant experience, including direct experience in this locale. As a result, though the mitigations committed to would not eliminate this potential burden, it was given little weight.

338 Other potential adverse environmental effects on the socio-economic environment of local residents identified as burdens include effects on heritage resources and on the current use of lands and resources for traditional purposes by Aboriginal persons. They also include other temporary disruptions to land use from construction along the proposed RoW. Given the proposed timing of construction, the location of the proposed pipeline along many already existing RoWs, the commitments made by EBPC with respect to heritage resources and traditional land uses, and the conditions the Board would impose should this Project be approved, the Board is of the view that very few residual effects would remain, and those that would remain would be short-term in nature (i.e., during the construction period only). Therefore, these burdens have been given moderate to low weight.

339 With regard to potential commercial burdens created by the Brunswick Pipeline, the Board recognizes that there is a significant difference on a per GJ basis between the tolls on the Brunswick Pipeline and the M&NP Canada system. However, the Board notes that there is no evidence on the record that shows that protecting the M&NP Canada system and its shippers from competition would serve the Maritime market in a more efficient manner than in letting it operate on its own. In fact, the shippers on M&NP Canada either supported the Project or did not oppose it. Accordingly, the Board gave little weight to the assertion that the tolls on M&NP Canada would become less competitive in the presence of the Brunswick Pipeline.

8.4 Balancing of Benefits and Burdens

340 The weighing of benefits and burdens with respect to the application before the Board for the Brunswick Pipeline Project was a difficult task. Many of the benefits, as can be seen from the foregoing analysis and the preceding Chapters, are national or regional in scope; few are specifically local. With respect to the burdens, the reverse is true; the majority of the burdens of the Project will be shouldered by the local community. As previously mentioned, it is not unusual that the burdens are often borne by the local community; however, often there is a broader local benefit that arises from a facility, particularly if the facility in question permits the production of local or regional resources.

341 With respect to the Board's consideration of the benefits and burdens of this Project under Part III of the NEB Act, the Board notes that its conclusion under the CEA Act that the Project would not be likely to cause significant adverse environmental effects, does not imply that there would be no adverse environmental or socio-economic effects associated with the Project. There still may be some adverse environmental or socio-economic effects that should be considered in identifying, weighing and balancing the overall benefits and burdens of the pipeline under the NEB Act. The Board must balance the totality of benefits against the totality of burdens to come to its final determination under section 52 of the NEB Act as to whether the Project is in the present and future public interest and necessity.

342 In weighing the benefits and burdens for this Project, the Board found that there were significant benefits from the local, regional and national perspectives in the opportunities associated with the access to a new, stable and secure supply of gas to this part of Canada. That being said, the Board recognizes that there are burdens associated with this Project that can not be completely mitigated and that these burdens rest primarily within the local community. Through the imposition of conditions and the guidance provided to EBPC throughout this document with respect to the importance of meaningful public consultation, the Board has determined that the burdens to the local community of Saint John can be further mitigated to the point that they are significantly less than the benefits that will accrue from this Project.

343 As mentioned in Chapter 6, the Board is of the view that EBPC could have pursued additional opportunities to improve its role and contribution to Saint John and Maritime Canada. The Board recommends that EBPC re-evaluate whether its role and contribution within Saint John and Maritime Canada have been maximized. The Board finds that such a re-evaluation, in combination with an improved ongoing public consultation program, would better demonstrate EBPC's stated position regarding its commitment to responsible corporate conduct and its desire to build a long-term partnership with Saint John and other communities throughout New Brunswick.

344 Therefore, on whole, taking into account all of the evidence in this proceeding, considering all relevant factors, and given that there are clear substantial benefits regionally and nationally, through which the local community will indirectly benefit, as well as some direct local benefits, the Board finds that the benefits of this Project outweigh the burdens. Accordingly, the Board concludes that the Project is in the present and future public convenience and necessity, and in the Canadian public interest.

8.5 Acknowledgements

345 The Board would like to acknowledge the participation of all parties in the hearing associated with this application. The Board is committed to ensuring that all stakeholders are engaged effectively in the Board's public process. One aspect of this commitment is to have effective public participation in oral hearings before the Board.

346 In this proceeding, there was a high level of participation by individuals and groups who had not previously appeared in front of a quasi-judicial tribunal. The time and effort that these parties spent to meaningfully participate in the public hearing was noted, and through their participation, the Board collected evidence that was highly relevant to its deliberations.

Chapter 9

Disposition

347 The foregoing chapters constitute our Reasons for Decision in respect of the application heard by the Board in the GH-1-2006 proceeding.

348 The Board is satisfied that the proposed Brunswick Pipeline Project is, and will be, required by the present and future public convenience and necessity, provided that the terms and conditions outlined in Appendix V, including all commitments made by EBPC during the hearing process, are met. Therefore, subject to the approval of the Governor in Council, a Certificate of Public Convenience and Necessity incorporating the terms and conditions in Appendix V will be issued pursuant to Part III of the NEB Act.

349 In addition, the Board finds the tolls and tariff to be charged to be just and reasonable, and not unduly discriminatory. Accordingly, the Board approves the tolls for the Brunswick Pipeline pursuant to Part IV of the NEB Act. Finally, the Board finds it appropriate for EBPC to be designated a Group 2 company, and orders that it be so designated.

S. Leggett
Presiding Member

K. Bateman
Member

S. Crowfoot
Member

* * * * *

Appendix I

Summary of Events

Following the filing of the project description for the Brunswick Pipeline Project by M&NP on 6 January 2006, the NEB had discussions with the CEA Agency, affected federal departments and the NB Department of Environment regarding the EA process for the Project.

On 16 March 2006, the Board sent a letter to the Minister of Environment referring the Project to a panel review and requesting that the Minister approve the substitution of the NEB process for an EA by a review panel pursuant to subsection 43(1) of the CEA Act.

On 5 April 2006, NEB staff held a public information session in Saint John to share information about the NEB's role, responsibilities and mandate, and to explain how the public could become involved in the NEB's regulatory process for the Project.

On 3 May 2006, the Minister of the Environment, the Honourable Rona Ambrose, pursuant to her authority under the CEA Act, referred the Project to a panel review and approved the Board's request for substitution.

A draft EA scoping document was released for public comment on 5 May 2006. Several comments were received during the public comment period, which closed on 7 June 2006, with additional comments received from the Applicant on 12 June 2006. The final EA scoping document was released on 23 June 2006.

The NEB received the application for the Project on 23 May 2006 from EBPC as the new owner of the Project, and on 9 June 2006, the NEB issued the Hearing Order for the GH-1-2006 proceeding, which included a List of Issues and a schedule of events leading up to the 6 November 2006 oral portion of the public hearing.

On 19 and 20 June 2006, NEB staff held public information sessions in Saint John to assist individuals in selecting a method of participation and preparing for effective and meaningful participation in the public hearing process for the Project.

A pipeline route orientation was conducted by the Board and two staff on 11 October 2006 to view, by helicopter and by vehicle, some of the locations and landmarks referenced in the evidence submitted in the proceeding in order to help the Board better understand the evidence.

The next day, 12 October 2006, the Board and staff held pre-hearing planning sessions in Saint John to assist parties in their preparation for the NEB public hearing on the Project, and to invite Intervenor feedback to assist in the planning for the oral portion of the hearing.

The oral portion of the hearing took place from 6 November to 20 November 2006 at the Hilton Saint John Trade and Convention Centre in Saint John, NB. Final argument by written submission concluded on 22 December 2006.

The NEB EA Report was released by the Board on 11 April 2007, and the government response to that EA Report was approved by the Governor in Council on 17 May 2007.

* * * * *

Appendix II

List of Issues

In Hearing Order GH-1-2006, the Board identified but did not limit itself to the following issues for discussion in the proceeding:

1. The need for the proposed facilities.
2. The appropriateness of the design of the proposed facilities.
3. The safety of the design and operation of the proposed facilities.
4. The economic feasibility of the proposed facilities.
5. The potential commercial impacts of the proposed project.

6. The potential environmental and socio-economic effects of the proposed facilities, including those factors outlined in subsections 16(1) and 16(2) of the *Canadian Environmental Assessment Act*.
7. The appropriateness of the general route and general land requirements of the pipeline.
8. The method of toll and tariff regulation, including the request by EBPC that it be regulated as a Group 2 Company (as described by the Board's Memorandum of Guidance dated 6 December 1995 on the Regulation of Group 2 Companies).
9. The terms and conditions to be included in any approval the Board may issue.

* * * * *

Appendix III

Brunswick Pipeline Estimated Capital Cost

($CDN millions)

Pipeline Materials	87.0
Measurement Materials	1.8

Subtotal Materials	88.8
Pipeline Contracts	179.6
Measurement Contracts	0.9

Subtotal Contracts 180.5

Engineering, Development & Land 49.6

Subtotal All Costs 318.9

Contingency 16.8

AFUDC 14.7

Total 350.4

* * * * *

Appendix IV

Brunswick Pipeline Pipe Specifications

	Urban (KP 0	Rural (KP 31.152-

	-KP 31.152)	KP 144.249)
Class Location	3	1
Pipe Outside Diameter (mm)	762	762
Length (km)	31.152	113.097
Grade (MPa)	483	483
Category	II	II
Maximum Operating Pressure (kPa)	9 930	9 930
Minimum Wall Thickness* (mm)	15.7	9.8
Pipe Coating	Fusion bond epoxy	Fusion bond epoxy
Joint Coating	Spray or roll on epoxy	Spray or roll on epoxy

* includes a few hundred metres of 15.9 mm wall thickness pipe at railway crossings where pipe is within seven metres of railway track.

* * * * *

Appendix V

Certificate Conditions

General Conditions

1. EBPC shall cause the approved Project to be designed, located, constructed, installed, and operated in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during questioning or in its related submissions.
2. EBPC shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included in or referred to in its application or as otherwise agreed to during questioning or in its related submissions.

Prior to Construction

3. Commitments

   EBPC shall file with the Board and post on its company website, at least one hundred and twenty (120) days before the planned start of construction, a table listing all commitments made by EBPC during the proceedings, conditions imposed by the NEB, and the deadlines associated with each.

4. Consultation

   EBPC shall file with the Board for approval, at least seventy-five (75) days prior to the planned start of construction, a public consultation program for the construction and the operation phases of the Project.

5. Environmental Protection Plan

   EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a Project-specific Environmental Protection Plan (EPP). This EPP shall be a comprehensive compilation of all environmental protection procedures, mitigation measures, and monitoring commitments, as set out in EBPC's application for the Project, subsequent filings, evidence collected during the hearing process, or as otherwise agreed to during questioning or in its related submissions. The EPP shall describe the criteria for the implementation of all procedures and measures, and shall use clear and unambiguous language that confirms EBPC's intention to implement all of its commitments. Construction shall not commence until EBPC has received approval of its EPP from the Board.

   The EPP shall address, but is not limited to, the following elements:

a) environmental procedures including site-specific plans, criteria for implementation of these procedures, mitigation measures and monitoring applicable to all Project phases, and activities;
b) site-specific construction plans for wetlands where they cannot be avoided;
c) site-specific plans for habitat harboring Species at Risk and of

Conservation Concern where it cannot be avoided;

d) project-specific acid rock drainage mitigation measures;
e) a construction and reclamation plan for Rockwood Park with evidence demonstrating consultation with stakeholders;
f) a reclamation plan which includes a description of the condition to which EBPC intends to reclaim and maintain the right of way once the construction has been completed, and a description of measurable goals for reclamation; and
g) evidence of consultation with relevant regulatory authorities that either confirms satisfaction with the proposed mitigation or summarizes any unresolved issues with the proposed mitigation.

6. Environmental Follow-up Programs

EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a description of follow-up programs as required by the *Canadian Environmental Assessment Act*. The programs shall verify the accuracy of the environmental assessment predictions and assess the effectiveness of mitigation for:

* fish and fish habitat as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);
* wetlands as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);
* access management as detailed in the Access Management Plan (Condition 11); and
* horizontal directional drill (HDD) noise management (Condition 15); and
* reclamation of Rockwood Park (Condition 5e).

Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board.

These descriptions of follow-up programs shall include a schedule for the submission of follow-up reports to the Board.

7. Traditional Ecological Knowledge Study Recommendations

EBPC shall file with the Board, at least sixty (60) days prior to construction, an update on the implementation of the six recommendations identified in the Traditional Ecological Knowledge Study (July 2006).

8. Construction Schedule

EBPC shall, at least thirty (30) days prior to construction, file with the Board a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur.

9. Construction Inspection Program

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a construction inspection program. The program shall include:

a) a preliminary list of the number and type of each inspection position, including job descriptions, qualifications, roles, responsibilities, and decision-making authority;
b) a discussion of how any changes to the items outlined in (a) would be determined during the course of construction; and
c) the reporting structure of personnel responsible for inspection of the various pipeline construction activities, including environment and safety.

10. Archaeological Studies and Monitoring Plan

EBPC shall consult with the Archaeological Services Unit of New Brunswick on further studies and a monitoring plan for areas with high potential for heritage resources, once the locations for detailed right of way, facility sites and temporary work space have been determined. EBPC shall file with the Board for approval, at least thirty (30) days prior to construction:

a) for approval, a report that documents how archaeological and heritage resources within the detailed route have been identified, recorded and mitigated;
b) copies of any correspondence from, or a summary of any discussions with the Archaeological Services Unit of New Brunswick regarding the acceptability of EBPC's report and proposed mitigation measures; and
c) for approval, a copy of any proposed monitoring plan.

11. Access Management Plan

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a Project-specific Access Management Plan that includes:

a) EBPC's goals and measurable objectives regarding the Access Management Plan;
b) the methods and procedures to be used to achieve the mitigation goals;
c) the criteria to determine if the mitigation goals have been met;
d) the frequency of monitoring activities along the right of way;
e) a description of the adaptive measures that will take place in the event that access management measures are ineffective; and
f) evidence of consultation with relevant regulatory authorities and landowners that either confirms satisfaction or summarizes any unresolved issues with the proposed mitigation.

Construction shall not commence until EBPC has received approval of its Access Management Plan from the Board.

12. Construction Manuals

EBPC shall file with the Board the following programs and manuals within the time specified.

a) Construction safety manual fourteen (14) days prior to construction;
b) Field joining program fourteen (14) days prior to joining; and,
c) Field pressure testing program fourteen (14) days prior to pressure test.

13. Infrastructure Facilities

EBPC shall file with the Board, at least seven (7) days prior to construction, the identity of all underground infrastructure utilities to be crossed by the Project, and confirmation that all the agreements or crossing permits for those facilities to be crossed have been acquired or will be acquired prior to construction.

During Construction

14. Construction Progress Reports

EBPC shall file with the Board, on a monthly basis until construction is completed, in a form satisfactory to the Board, construction progress reports. The reports shall include information on the activities carried out during the reporting period, any environmental and safety issues and non-compliances, and the measures undertaken for the resolution of each issue and non-compliance.

15. HDD Noise Management Plan

EBPC shall file for approval, at least ninety (90) days prior to the start of the HDD activity proposed for the Saint John River Crossing, a detailed noise management plan containing information on day-time and night-time HDD operations at the drill exit and entrance sites, including but not limited to the following:

a) ambient sound levels at noise sensitive areas close to the HDD exit and entrance sites to establish a baseline for assessing potential noise impacts;
b) predicted noise level at the most affected residences caused by the HDD without mitigation;
c) proposed HDD noise mitigation measures, including but not limited to the following:

    i. all technologically and economically feasible mitigative measures as presented in Section 5.1.7 of the Environmental and Socio-economic Assessment (Jacques Whitford, 2006) and in the Resource Systems Engineering assessment;
    ii. the use of full enclosures on diesel powered units;
    iii. the use of quiet machinery (where feasible);
    iv. the undertaking of HDD activities during periods where residential windows would be expected to be closed (i.e., during winter months);

d) predicted noise level at the most affected residences with implementation of the mitigation measures;
e) noise contour map(s) showing the potentially affected residences at various noise levels;
f) a noise monitoring program including locations, methodology and schedule;
g) confirmation that residents potentially affected by HDD noise will receive contact information for EBPC in the event they have concerns about the HDD noise;
h) a contingency plan with proposed mitigative measures for addressing noise complaints, which may include the temporary relocation of specific residents; and
i) confirmation that EBPC will provide notice to nearby residents in the event that a planned blowdown is required and that planned blowdowns will be completed during day-time hours whenever possible.

16. Saint John River Crossing

EBPC shall construct the crossing(s) of the Saint John River using the HDD method or, if this is not feasible, shall apply to the Board for approval of an alternative crossing technique and include an environmental assessment of the proposed alternative with its application.

17. Archaeological or Heritage Resource Discovery

EBPC shall notify the Board, at the time of discovery, of any archaeological or heritage resources and, as soon as reasonable thereafter, file with the Board for approval a report on the occurrence and proposed treatment of the archaeological/heritage resources, any changes to the archaeological/heritage monitoring plan, and the results of any consultation, including a discussion on any unresolved issues. If no discoveries are made, please indicate that when complying with condition 20.

Prior to Operation

18. Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, an Emergency Procedures Manual (EPM) for the Project and shall notify the Board of any modifications to the plan as they occur. In preparing its EPM, EBPC shall refer to the Board letter dated 24 April 2002 entitled "Security and Emergency Preparedness Programs" addressed to all oil and gas companies under the jurisdiction of the National Energy Board.

19. Consultation on Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, evidence of consultation with stakeholders identified in the EPM, including a summary of any unresolved issues identified in consultations, and evidence that the EPM addresses, to the extent possible, any issues raised during consultation.

Post-construction and During Operations

20. Condition Compliance by a Company Officer

Within thirty (30) days of the date that the approved Project is placed in service, EBPC shall file with the Board a confirmation, by an officer of the company, that the approved Project was completed and constructed in compliance with all applicable conditions in this Certificate. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the Board details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

21. Emergency Response Exercise

a) Within six (6) months after commencement of operation of the Project, EBPC shall conduct an emergency response exercise with the objectives of testing:

* emergency response procedures;
* training of company personnel;
* communications systems;
* response equipment;
* safety procedures; and
* effectiveness of its liaison and continuing education programs.

b) EBPC shall notify the Board, at least thirty (30) days prior to the date of the emergency response exercise, of the following:

* the date and location(s) of the exercise;
* the participants in the exercise; and
* the scenario for the exercise.

c) EBPC shall file with the Board, within sixty (60) days after the emergency response exercise outlined in (a), a report on the exercise including:

* the results of the exercise;
* areas for improvement; and
* steps to be taken to correct deficiencies.

22. Emergency Response Exercise Program

Within six (6) months after commencement of operation of the Project, EBPC shall file with the Board a description of the company's emergency response exercise program, including:

* the frequency and type of exercises (full-scale, table-top, drill) it plans to conduct; and
* how the results of any emergency response exercises will be integrated into the company's training and exercise programs.

23. Post-construction Environmental Reports

Within six (6) months following commencement of operation of the Project, and on or before the 31st of January following each of the second (2nd) and fourth (4th) complete growing seasons following commencement of the operation of the Project, EBPC shall file with the Board a post-construction environmental report that:

a) identifies on a map or diagram any environmental issues which arose during construction;
b) provides a discussion of the effectiveness of the mitigation applied during construction;
c) identifies the current status of the issues identified, and whether those issues are resolved or unresolved; and
d) provides proposed measures and the schedule EBPC shall implement to address any unresolved concerns.

24. Environmental Follow-up Program Reports

EBPC shall file with the Board, based on the schedule referred to in Condition 6, the report(s) outlining the results of the follow-up programs.

25. Certificate Expiration

Unless the Board otherwise directs prior to 31 December 2008, this Certificate shall expire on 31 December 2008 unless construction in respect of the Project has commenced by that date.

* * * * *

Appendix VI

Significant Rulings

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31 August 2006	Ruling Number 3 - EBPC Notice of Motion, dated 31 July 2006, for confidentiality under Section 16.1 of the *National Energy Board Act*
20 September 2006	Ruling Number 6 - Request on behalf of Anadarko, dated 25 August 2006
21 September 2006	Ruling Number 7 - Ms. T. Debly's Notice of Motion to require EBPC to respond to Information Requests

23 October 2006	Ruling Number 10 - Objections to Late Filings, Filing of Late Letters of Comment and Requests to File Late Evidence
8 November 2006	Board Ruling on request of Friends of Rockwood Park to file Pembina Institute Report on Municipal Infrastructure
9 November 2006	Board Ruling on Dr. Thomas' Request to revisit the Scope of the Project
16 November 2006	Board Ruling on Questioning about Alternative Means
17 November 2006	Board Ruling on Questioning about Alternatives to the Project

Ruling Number 3 - EBPC Notice of Motion, dated 31 July 2006, for confidentiality under Section 16.1 of the *National Energy Board Act* (NEB Act)

Background

As part of EBPC's application, it requested an order from the Board approving the toll to be charged by EBPC under Part IV of the NEB Act. EBPC also indicated that it has reached a confidential toll agreement with its only shipper, Repsol Energy Canada Ltd. (Repsol). Under this agreement, Repsol would pay all fixed charges applicable to the Brunswick Pipeline over the first 25 years of its operation, including an investment return. EBPC indicated that it would file this toll agreement with the Board.

By motion dated 31 July 2006, EBPC applied under section 16.1 of the NEB Act to file, in confidence, the toll agreement. A copy of the toll agreement was subsequently submitted on 10 August 2006, as was a copy of a precedent agreement and redacted versions of the toll agreement and the precedent agreement. EBPC seeks protection under section 16.1 for the redacted portions of the toll agreement and the precedent agreement (the Agreements).

By letter dated 4 August 2006, the Board sought comments from the parties to this proceeding with respect to EBPC's motion. Numerous comments were received. EBPC filed its reply on 22 August 2006.

Submissions of Parties

EBPC indicated that the Agreements contain commercially sensitive information, the disclosure of which could reasonably be expected to prejudice Repsol's competitive position, as LNG transportation costs are a significant component of an LNG shipper's business strategy. Transportation costs are a factor in the competition between LNG projects for supply. In addition, there are many LNG projects under development which propose to serve, in part or in whole, the same market areas. EBPC also indicated that it has filed the Brunswick Pipeline System Firm Service Agreement, which contains the terms and conditions of service on the Brunswick Pipeline, and the redacted versions of the Agreements, so there is no need to publicly disclose the financial, economic and commercially sensitive information contained in the Agreements. The redacted Agreements provide parties with sufficient information to understand the nature and mechanics of Repsol's contractual commitments to the Brunswick Project.

EBPC further submitted that the redacted portions of the Agreements have been consistently treated as confidential by it and Repsol. EBPC stated that these parties' interest in confidentiality outweighs the public interest in disclosure of such information.

Repsol supported EBPC's motion, adopted EBPC's submissions and indicated that the disclosure of the information would be prejudicial to the commercial interests of Repsol.

A number of parties opposed the motion. The arguments in opposition include, but are not limited to:

1. The Agreements should be public because this application is for a certificate of public convenience and necessity and therefore all matters should be public or transparent, and that the public interest outweighs the interest of the companies.
2. Section 62 of the NEB Act states that tolls must be just and reasonable and charged equally to all persons at the same rate, and since justice must not just be done but be seen to be done, the public must see the Agreements for the purpose of determining their validity.
3. The information is required to assess the economic feasibility of the Project.
4. The redacted portions describe the constituent elements of its toll as well as the method by which the toll might be adjusted once construction costs are known. EBPC has requested that the Board approve the negotiated toll. The negotiated toll is an essential matter in the proceeding, and section 16.1 could not have been intended to allow the subject matter of a proceeding to be kept secret from the parties who are interested in a project before the Board.
5. Part IV of the NEB Act requires the filing and/or approval of tolls. The scheme of the Act contemplates a published tariff with a schedule of tolls, and that this transparency ensures that others seeking service feel that they are receiving fair treatment.
6. EBPC is entering a pipeline marketplace in which open access is the policy, and for which published tariffs and tolls form the cornerstone. Secret toll and related terms are not consistent with open access.
7. With respect to EBPC's argument regarding competitive LNG transportation costs, it was argued that offshore gas should not be

given an advantage over onshore gas insofar as public disclosure of pipeline transportation rates is concerned. These costs are a factor for all gas suppliers. In any event, after re-gasification, this is just natural gas, not LNG, competing with other natural gas in the market. EBPC is seeking a competitive advantage for Repsol over those suppliers of natural gas whose pipeline transportation costs are public. This is not consistent with the prevailing scheme of regulation or with market transparency.

8. There was no compelling evidence that the disclosure of the information could reasonably be expected to result in a material loss or gain to any party or to prejudice any party's competitive position. EBPC has not provided any evidence to discharge its onus, but has given only bare assertions of commercial sensitivity and prejudice, which should be given little weight.

EBPC's reply submitted, among other things, that the intervenors have failed to provide any reasoned basis for requiring disclosure of the commercially sensitive information EBPC and Repsol seek to keep confidential. EBPC stated that specific toll numbers are not required to determine pipeline economic feasibility, because it is on the public record that the pipeline's costs will be paid by Repsol (guaranteed by its parent company) and the capacity will be used at reasonable levels over its economic life, as indicated by the 25 year firm service commitment by Repsol, and the substantial upstream and downstream investments by Repsol.

EBPC further argued that Repsol requested confidentiality and that no other shippers have requested service, and therefore there is no commercial prejudice to any other shipper to maintain this confidentiality. EBPC indicated that it nevertheless would disclose the actual toll information to *bona fide* potential shippers requesting service.

Section 16.1 of the National Energy Board Act

Section 16.1 of the NEB Act states:

> In any proceedings under this Act, the Board may take any measures and make any order that it considers necessary to ensure the confidentiality of any information likely to be disclosed in the proceedings if the Board is satisfied that
>
> a) disclosure of the information could reasonably be expected to result in a material loss or gain to a person directly affected by the proceedings, or could reasonably be expected to prejudice the person's competitive position; or
> b) the information is financial, commercial, scientific or technical information that is confidential information supplied to the Board and

(i) the information has been consistently treated as confidential information by a person directly affected by the proceedings, and

(ii) the Board considers that the person's interest in confidentiality outweighs the public interest in disclosure of the proceedings.

This section provides an exception to the fundamental principle that the Board's proceedings are to be open, accessible and transparent. As an exception, the onus is not upon the parties opposing confidentiality to show why the information should be public; rather those seeking a confidentiality order have the onus to show why this extraordinary order should be granted to keep information in a public proceeding confidential.

In its application, EBPC has requested an order approving the toll to be charged by EBPC. Accordingly, the decision the Board has to make requires evidence relating to the toll to be charged. By default this evidence should be public unless EBPC can persuade the Board that that information falls within the narrow and limited exceptions set out by section 16.1.

Subsection 16.1(a)

The only evidence EBPC has put forward to justify its request for a confidentiality order is that it is commercially sensitive information, the disclosure of which could reasonably be expected to prejudice Repsol's competitive position, as LNG transportation costs are a significant component of an LNG shipper's business strategy. Transportation costs are a factor in the competition between LNG projects for supply. In addition, EBPC noted that there are many LNG projects under development which propose to serve, in part or in whole, the same market areas. Though Repsol adopted EBPC's submissions, it did not provide any evidence to supplement those submissions.

The Board is of the view that the link between LNG transportation costs and tolls to be paid on the Brunswick Pipeline remains tenuous. At the entry point of the Brunswick pipeline, the product would be natural gas, not LNG, and the tolls to be paid by Repsol are tolls for the transportation of natural gas, not LNG. The tolls are collected by EBPC, who does not have LNG transportation costs. Filing the tolls on the public record would not disclose Repsol's LNG transportation costs and thus not compromise its competitiveness on the supply side.

The Board notes that transportation costs are a factor in the strategy and the competitive environment of all shippers. In addition, shippers often are competing in the same markets. For example, a shipper on M&NP or on TCPL is subject to public tolls for the transportation of their product to markets. These markets include those identified by Repsol as regions to which it intends to ship its product.

The Board is of the view that EBPC has not provided sufficient evidence to persuade the Board that disclosure of the redacted portions of the Agreements could reasonably be expected to result in a material loss or gain to Repsol, or could reasonably be expected to prejudice Repsol's competitive position.

Subsection 16.1(b)

EBPC also stated that this information has been consistently treated as confidential by the parties and that the interest in confidentiality outweighs the public interest in disclosure. Both of these factors address the requirements of subsection 16.1(b). However, this is only one aspect of the test set out in subsection 16.1(b). The Board must also consider whether the person's interest in confidentiality outweighs the public interest in disclosure of the proceedings.

EBPC has addressed the public interest aspect of s. 16.1(b) by stating that other parties do not need this information, as there is sufficient information on the record to demonstrate economic feasibility, and fair access. However, whether other parties will be prejudiced if the information is *not* disclosed is not the test EBPC has to meet.

Further, the public interest to be weighed is not just the public interest of these particular intervenors to make their arguments using the evidence already filed. The Board has defined "public interest" much broader than the specific interests of the parties involved in a particular hearing. For example, on the Board's website, the Canadian public interest is defined as follows:

> "The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that changes as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision."

The public interest also involves the interest in open and accessible proceedings. In its application, EPBC has requested that the Board make an order approving the tolls to be charged. There is a general public interest in ensuring that the basis of any Board decision is founded on evidence that is in the public domain, that is, the evidence upon which the Board relies to come to a decision is open and accessible; such public interest is reflected in the principles of natural justice and procedural fairness.

The Board is of the view that EBPC has not provided sufficient evidence to persuade the Board that Repsol's interest in confidentiality of the redacted portions of the Agreements outweighs the public interest in disclosure of the proceedings.

Ruling

After considering all of the comments received, and for the reasons stated above, the Board denies EBPC's motion to file the redacted portions of the Agreements confidentially. The original Agreements filed with the Board will be returned to counsel for EBPC by courier under cover of a separate letter.

The Board notes that EBPC is requesting an order of the Board approving its tolls. In order to allow the GH-1-2006 proceeding to continue as currently scheduled, the Board encourages EBPC to file the information relating to the tolls as soon as possible.

Ruling Number 6 - Request on behalf of Anadarko, dated 25 August 2006

On 10 August 2006, the Board issued Ruling 1 regarding the scope of the GH-1-2006 proceeding and setting out its expectations that Bearhead LNG Corporation, Anadarko LNG Marketing, Corp., and Anadarko LNG Marketing, LLC. (collectively, "Anadarko") would combine any comments it had regarding EBPC's responses to Anadarko's IRs with any relief Anadarko may be seeking with respect to IRs directed at Maritimes & Northeast Pipeline Limited Partnership (M&NP), so that all matters arising out of the same IRs may be considered concurrently.

On 25 August 2006, the National Energy Board received Anadarko's renewed request to compel M&NP to file responses to Anadarko's IRs and specifically IRs 1.3(f), 1.7(a), (b) & (c) and 1.11(a), (b) & (c). On 30 August 2006, the Board invited EBPC and M&NP to provide comments by 6 September 2006 and invited Anadarko to reply by 8 September 2006.

Anadarko argued that the evidence filed on the record up to 25 August 2006 demonstrates that Repsol and M&NP had contemplated a precedent agreement in which Repsol would have used the M&NP system for its gas. M&NP could have taken the same position with Repsol that it did with Anadarko to pay a postage stamp toll on the M&NP system. However, M&NP chose instead to facilitate a "stand-alone" pipeline and thus a "stand-alone" toll, unrelated to the M&NP system. Furthermore, Anadarko argued that its evidence, filed 25 August 2006 shows that, had M&NP negotiated a toll with Repsol on the M&NP system, there would have been benefits to M&NP shippers such as lower tolls and the opportunity to turn back unused capacity.

M&NP has unique knowledge of the circumstances which led it to allow bypass of its own system, the alternatives it considered and the basis upon which other shippers requesting expansion services will be treated. In Anadarko's view, these issues bear directly on the matters before the Board in this application.

In its 6 September 2006 comments, M&NP reasserted its intention to only monitor the proceeding and reiterated that it did not intend to file evidence. M&NP argued that the Brunswick Pipeline is not a "bypass" project because it is not a duplication of existing M&NP facilities, nor does it displace current loads on the M&NP system. M&NP argued that the "alternatives" of using the M&NP system were rejected early on without the necessity of detailed analysis by EBPC because they did not meet the technical requirements, let alone Repsol's requirement for a stand-alone pipeline. Furthermore, according to M&NP, Anadarko and others have been and will continue to be treated fairly in their requests for service.

M&NP argued that Anadarko's IR 1.3(f) is irrelevant on the basis that the precedent agreement between M&NP and Repsol has terminated. Furthermore, IRs 1.7 and 1.11 are an attempt by Anadarko to convert EBPC's application under section 52 of the *National Energy Board Act* (NEB Act) into one that would compel M&NP to prepare its own application and to potentially provide service to a market (Repsol) that does not want it. M&NP submits that the Board has previously stated that there is no jurisdiction to direct the filing of such an application nor has Anadarko cited authority to permit it to force its competition (Repsol) to use a different pipeline system than that which Repsol has chosen.

EBPC argued that Anadarko's request goes beyond the testing of the adequacy of EBPC's analysis of alternatives by forcing a different company to sponsor a new alternative. This effort is without procedural precedent and pointless given that no authority has been cited in support. The Board cannot force a pipeline company to file an application, and mandated carriage or facilities expansion under section 71 of the NEB Act is not available to support Anadarko's request because Repsol is not offering any gas to M&NP for transport on M&NP's system. Finally, EBPC is prejudiced by the introduction of new parties and hypothetical projects.

On 8 September 2006, Anadarko replied that M&NP's submissions, including that it only plans to monitor the proceeding, demonstrate that it does not intend to accede to Anadarko's request and as such, the Board must compel M&NP to answer the IRs. M&NP is more than a bystander and is in possession of evidence relevant to the Board's decision under the NEB Act.

Anadarko submitted it wishes to ensure that the Board has all relevant information and that expansion is offered on a fair and non-discriminatory basis. It does not wish to require M&NP to build new facilities.

The Board's test for determining whether to compel a party to answer IRs is whether the information is relevant, significant and is a reasonable request in the context of the particular proceeding. The IRs in dispute seek to determine the outcome of commercial arrangements that are neither in place nor are expected to be in place in the foreseeable future, based on the evidence submitted in this proceeding.

Nor is the Board persuaded that any probative value to be gained by requiring M&NP to answer Anadarko's IRs, and specifically IRs 1.7 and 1.11, would outweigh the burden on M&NP to prepare that information. Accordingly, Anadarko's 25 September request to have M&NP answer Anadarko's IRs, and specifically IRs 1.3 (f), 1.7(a), (b) & (c) and 1.11(a), (b) & (c) is denied.

Ruling Number 7 - Ms. T. Debly's Notice of Motion to require EBPC to respond to Information Requests (IRs)

On 7 September 2006, Ms. Debly filed a Notice of Motion to require EBPC to respond to certain IRs submitted by her and by the Estate of A.J. Debly. In addition, she requested an extension to the deadline for filing her evidence until 15 days after EBPC responded to these IRs. The Board sought comments from EBPC and Ms. Debly before making its determination, and received comments from EBPC dated 13 September 2006 and from Ms. Debly dated 18 September 2006.

Criteria for Responding to Information Requests

Before coming to the views of the Board with respect to the motion, it may be helpful to set the information request process into the context of the Board's overall role as a decision-maker.

While the Board is not formally bound by the rules of evidence, it may not take into account facts that have no logical connection to the decision it has to make, nor fail to take into account relevant and material facts. Relevant facts are provided in a number of ways, including through the application, through evidence filed in support of the application, and through responses to information requests posed by the Board or by parties to a proceeding, or through evidence filed by other parties to the proceeding.

Sections 32 to 34 of the *National Energy Board Rules of Practice and Procedure, 1995* (the Rules) deal specifically with the information request process. These rules provide that in response to an information request, a party must provide one of the following: a full and adequate response to the information request; a statement setting out the objection to responding and the grounds therefore; or a statement that the information is not available, setting out the reasons for the unavailability and the alternative available information that may be of assistance.

With respect to the general purpose of information requests and the criteria used to decide when an applicant will be directed to respond to a request, the Board has previously stated:

> The Board process allows for the use of written information requests for a number of reasons. Applications before the Board require the consideration of substantial information, much of it of a detailed and technical nature. Often this information is not conducive to an examination by the oral cross-examination process. Parties are therefore encouraged to obtain and examine such information through the established information request process. This process can be used to obtain the evidence necessary to test and explore the Applicant's case and, in the case of Intervenors, to assist them in preparing their cases.
>
> ... When the parties cannot agree on the appropriateness of the Information Request or the adequacy of a Response, the Board is asked to provide direction. When considering such a motion, the Board looks at the relevance of the information sought, its significance and the reasonableness of the request. It seeks to balance these factors to ensure that the purposes of the Information Request process are satisfied, while ensuring that an Intervenor does not engage in a "fishing expedition" that could unfairly burden the Applicant.[29]

The criteria of relevance, significance and reasonableness have been applied in a number of proceedings before the Board.[30]

In determining whether the information sought to be elicited through the information request process in this proceeding should be provided, the Board is of the view that a similar analysis should be undertaken; looking at whether the information requested is relevant, whether it is significant (or probative) and whether the request is reasonable, and balancing these factors to ensure that the purpose of the information request process has been satisfied.

Cumulative Environmental Effects Assessment

In addition to the criteria set out above, as the IRs are raised in the context of the Board's letter on the Environmental Assessment Scoping Document, dated 23 June 2006, some discussion of how cumulative effects assessments are carried out in the Board's process is useful. The approach to cumulative effects assessment reflected in Guide A, Section A.2.6 of the National Energy Board's Filing Manual (the Manual) is to undertake the following sequential steps:

1. Identify the potential effects for which residual effects are predicted for the project being assessed (residual effects are those which would still exist after any mitigation is applied);
2. For each biophysical element where residual effects are identified, determine the spatial and temporal boundaries that will be used to assess the potential cumulative effects;
3. Identify other projects and activities that have occurred or are likely to occur within the residual effects boundaries and identify whether those projects and activities will produce effects on the biophysical element within the identified boundaries;
4. Consider whether the effects in (3) act in combination with the project's residual effects and if so, include those projects or activities in the cumulative effects assessment; and then
5. Analyze the cumulative effects of the proposed project in combination with other projects and activities for each biophysical element; this includes considering the residual effects of the proposed project in combination with the effects of other projects and activities and considering whether the proposed project is incrementally responsible for adversely affecting a biophysical element beyond an acceptable point (*i.e.,* threshold).

The Manual also states that "The level of effort and scale of the cumulative environmental effects assessment should be appropriate to the nature of the project under assessment; its potential residual effects; and the environmental and socio-economic setting."

The Board also wishes to emphasize that one of the purposes of the *Canadian Environmental Assessment Act* (CEA Act), as set out in paragraph 4(1)(b.1), is "to ensure that responsible authorities carry out their responsibilities in a coordinated manner with a view to eliminating unnecessary duplication in the environmental assessment process." As noted in the Board's 23 June 2006 letter, the Canaport[TM] LNG facility, including its environmental effects on air quality, has already undergone an environmental assessment by federal authorities under the CEA Act and by provincial authorities. That assessment is publicly available on the Canadian Environmental Assessment Agency's online registry.

Therefore, in carrying out its cumulative environmental effects assessment of the Brunswick Pipeline, the Board must ensure it is not being duplicative of environmental assessment processes already undertaken; and that it is the potential residual effects of the Brunswick Pipeline that are being assessed. The Board's consideration of other projects is only in the context of whether those other projects have effects that have the potential to act *in combination* with the Brunswick Pipeline's residual effects. Further, the nature of the Brunswick Pipeline project and its potential residual effects also inform the level of effort and scale of the cumulative effects assessment. It is within this context that the Board can consider terminal or tanker traffic *to the extent that they are relevant* as cumulative environmental effects that are likely to result for the Brunswick Pipeline in combination with other projects or activities that have been or will be carried out.

Specific Information Requests

IR EOD 1.3

The Board is of the view that IR EOD 1.3 from the Estate of A.J. Debly has been sufficiently responded to by EBPC in its responses. Accordingly, the Board will not direct EBPC to further respond to this IR.

IRs TD 1S.12, TD 1S.13, TD 1S.17 and TD 1S.18

Based on the context noted in the previous section, and balancing the three criteria of relevance, significance and reasonableness set out above, the Board is of the view that these IRs seek information that does not appear to be sufficiently significant or probative to the Board's assessment of the cumulative effects of the Brunswick Pipeline to require EBPC to undertake a further response to these IRs.

However, the Board notes that Ms. Debly and the Estate of A.J. Debly may submit, as part of their own evidence, any evidence they feel is relevant to the cumulative environmental effects assessment and the Brunswick Pipeline's impact on air quality.

IRs TD 1S.15, TD 1S.16, and TD1S.20 to 1S.22

With respect to IRs 1S.15, 1S.16, and 1S.20 to 1S.22 of Ms. Debly's IRs, the Board is of the view that the information requested is not sufficiently significant or probative to the Board's consideration of EBPC's application to require EBPC to provide a further response to these IRs.

In the Board's view, the information sought appears to relate primarily to the broad issue of global greenhouse gas emissions, and their environmental effects. For example, the environmental effects of upstream LNG production in another country do not have the ability to act cumulatively with the environmental effects of the Brunswick Pipeline except on a global level. A focused and accurate assessment of these environmental effects is not feasible. As noted in the Manual, some spatial and temporal boundaries to the cumulative effects assessment have to be utilized.

In addition, in the Board's view, calculating the emissions of upstream LNG production or determining the end use(s) of gas transported on the Brunswick Pipeline regardless of the site of the LNG production or the end use of the gas would not be helpful to the determination it must make.

Considering these environmental effects would be a difficult exercise of little, if any, probative value. It is too broad, too speculative and of too little utility to be useful for the section 52 determination to be made by this Board. As a result, the Board will not direct EBPC to respond further to IRs 1S.15, 1S.16, and 1S.20 to 1S.22.

Conclusion

For the foregoing reasons, the Board hereby denies Ms. Debly's motion requesting EBPC to further respond to her and the Estate of A.J. Debly's IRs, and for a 15-day extension to Ms. Debly's deadline for filing written evidence.

Ruling Number 10 - Objections to Late Filings, Filing of Late Letters of

Comment and Requests to File Late Evidence

Background

The Board has received an objection to the Letter of Comment from Ms. L. McColgan, filed with the Board on 10 October 2006. A number of objections were also raised to the request to make an oral statement by Atlantic Institute for Market Studies (AIMS), whose request was filed 6 October 2006. The Board has also received Letters of Comment from Wallace MacMurray, on 13 October 2006, D.R. McColgan and David Hayward, filed with the Board on 17 October 2006. No objections have been received to the filing of these late Letters of Comment. All of these filings were made past the deadlines set out in the Hearing Order GH-1-2006 Timetable of Events, as amended.

The Board has also received two requests for permission to file late evidence from Ms. J. Dingwell, dated 11 October 2006, and from Mr. D. Robichaud, dated 13 October 2006. Furthermore, on 19 October 2006, Mr. Robichaud filed evidence in the form of a report by Accufacts. In addition, Ms. D. Fuller provided photographs to Board staff on 12 October 2006. The photographs were not accompanied by a request to the Board for permission to file them late.

This ruling deals with all of these matters.

Views of the Board

Criteria that may be considered

The Board is of the view that it would be helpful for all parties to be reminded of the criteria the Board may consider in determining whether to grant requests to file late evidence, late Letters of Comment or late requests to participate.

On any motion for the filing of late evidence, the Board considers whether the applicant for the relief has persuaded the Board that:

(i) the evidence is relevant;
(ii) that there is a justification for filing late or that the party has acted with due diligence to try to meet the deadline; and
(iii) that there will be little prejudice resulting to any party if the evidence is accepted into the record (taking into account any mitigative measures).
(iv) In addition, the Board may consider other factors, such as whether the probative value of the evidence outweighs any prejudice to other parties as a result of the lateness of receiving it; the efficiency and fairness of the Board's regulatory process and the mandate of the Board to make a fully informed decision on an application before it.

In other words, the Board considers whether the applicant for the late participation has provided a justification for what interest the person has in the application before the Board, why it is applying late, and whether any other party would be prejudiced by its participation.

When considering late Letters of Comment or late requests to participate, similar criteria are taken into account. In the case of late participation, the Board may also consider other factors, including whether the participant is likely to materially assist in the understanding of the issues raised by the application, and whether those who already are participating are able to sufficiently advance concerns relating to the public interest. The Board will also balance accommodation of views of those with an interest in the application and the need for an efficient regulatory process.

Turning now to the individual objections, late Letters of Comment and requests to file late evidence, and considering the criteria set out above, the Board finds as follows.

Ms. McColgan's Late Letter of Comment

Letters of Comment often contain both unsworn evidence and aspects of final argument. With respect to Ms. McColgan's late Letter of Comment, the Board notes that while the content of the letter may be relevant to the issues before the Board in this hearing, Ms. McColgan has not provided a justification for filing the Letter of Comment past the deadline (12 September 2006) nor provided any explanation as to why the letter could not have been provided within the timeframe set out in the Hearing Order, In addition no explanation has been given as to why the parties to the hearing will not be prejudiced by the late filing. The Board also notes that a letter of objection to this late request has been filed in these proceedings.

For these reasons, the Board has decided not to admit Ms. McColgan's Letter of Comment onto the record in this proceeding.

Mssrs. MacMurray, McColgan and Hayward's Late Letters of Comment

As permitted by the *National Energy Board Act*,[31] the Board has decided, on its own motion, to deal with the question of whether or not to admit late Letters of Comment filed by Mr. MacMurray, Mr. McColgan and Mr. Hayward. These Letters of Comment have been sent to the Board well past the deadline for filing Letters of Comment, as set out in the Hearing Order. As with Ms. McColgan's letter, none of these submissions provide a justification for filing them past the Board's deadline for filing such letters. Nor do they provide an explanation as to why parties to the hearing will not be prejudiced by the late filings.

For these reasons, the Board has decided not to admit the late Letters of Comment by Mr. MacMurray, Mr. McColgan and Mr. Hayward onto the record in this proceeding.

AIMS' Request to Make an Oral Statement

On 6 October 2006, AIMS submitted its request to make an oral statement. The request does not indicate the position AIMS will take at the oral hearing nor was it accompanied by a Letter of Comment. The request does not indicate why AIMS could not have filed its request by the deadline set out in the Timetable of Events, as amended. A number of parties objected to this late request of the basis that it was not submitted by the required deadline.

As noted in the Hearing Order, persons who make oral statements may not file anything in writing at the time of making their oral statements. Oral statement makers do not receive the application, are not entitled to ask information requests or cross-examine parties to the proceeding, or provide final argument. Oral statement makers are sworn in, make their oral statement, and then are available to be questioned on the statement by the Applicant and the Board and any other party with leave of the Board. As a general rule, only parties adverse in interest may seek leave to question oral statement makers.

The Board notes that the content of the oral evidence and argument to be provided by any oral statement maker is not known by any other party to this proceeding or other oral statement makers prior to the oral portion of the hearing, unless that person has accompanied their request with a Letter of Comment. While the content of the information is not known ahead of an oral statement being made, any prejudice suffered by a party as a result of the content of an oral statement can be rectified by questioning the oral statement maker by the party alleging prejudice.

In this instance, AIMS has not submitted its request within the timelines set out in the Hearing Order nor justified why a late filing should be accepted. Furthermore, AIMS has provided no explanation as to why parties would not be prejudiced by the late filing. While the Board notes that parties adverse in interest could be permitted to question AIMS on its oral statement, in this instance, the Board is not persuaded that, given the late date, AIMS should be permitted to make an oral statement at the hearing.

For these reasons, the Board has decided that AIMS shall not be permitted to present an oral statement at the oral hearing.

Ms. Dingwell's Request to File Late Responses to Information Requests

Ms. Dingwell has requested permission to file her responses to the information requests of Ms. Debly after the deadline set out in the Board's Ruling Number 9. She has indicated in her request that while she has gathered the information, she is awaiting verification by the Cherry Brook Zoo's director prior to submitting it, so as to ensure its accuracy. The Board has previously indicated that this information may be relevant to the issues before the Board and the resolution of those issues. The late information sought by the information request is of a factual nature; that is, it concerns facts related to the zoo's background. In the Board's view this type of information is not likely to create significant prejudice to other parties adverse in interest, particularly if the information is submitted prior to the commencement of the oral hearing. As an intervenor who has filed written evidence, Ms. Dingwell may be subject to cross-examination on this evidence by parties who are adverse in interest to her.

The Board is of the view that Ms. Dingwell's request should be granted. Ms. Dingwell is required to file this evidence with the Board and serve a copy on all parties prior to the commencement of the oral hearing.

Ms. Fuller's Photographs

During the pre-hearing planning conference held in November in New Brunswick, Ms. Fuller passed some photographs to a member of the Board's staff. Despite being advised of the procedure for filing late evidence, the photographs were not accompanied by a letter seeking permission to file the photographs late, or an explanation as to why these photographs could not have been filed in a timely manner. No explanation as to the relevance of these photographs to the issues before the Board was provided.

While in New Brunswick, the Board visited a number of locations suggested by parties to better their understanding of the evidence submitted. The majority of the locations in these photographs were visited by the Board. The Board is of the view that the probative value of these photographs does not outweigh the prejudice of introducing late intervenor evidence at this time in the proceeding. Accordingly, the photographs will not form part of the record in this proceeding and will be returned to Ms. Fuller.

Mr. Robichaud's Request to File Late Evidence

Mr. Robichaud has indicated in his 13 October 2006 letter that he was unable to find a specialist to complete a report for him until early in October. No report was attached to that letter, nor was a description of the subject matter or content, the name of the author or any other details related to the report. However, on 19 October 2006, Mr. Robichaud submitted, to the Board, a report by Accufacts entitled "*Commentary on the Risk Analysis For the Proposed Emera Brunswick Pipeline Through Saint John, NB*".

The Board has before it Mr. Robichaud's explanation of why he was not able to file the report earlier. It also has before it the report itself. However, before ruling on the admission of the report as late intervenor evidence, the Board has decided that it would like to hear comments from the Applicant, Emera Brunswick Pipeline Company (EBPC), regarding the admission of this report onto the record as late intervenor evidence.

Accordingly, EBPC is directed to file comments, if any, with the Board and serve a copy on Mr. Robichaud by no later that **5:00 p.m. Calgary time, on Tuesday 24 October 2006**.

Mr. Robichaud is directed to file a response, if any, with the Board and serve a copy on EBPC and its counsel by no later that **5:00 p.m. Calgary time, on Thursday 26 October 2006**. **Ruling on request of Friends of Rockwood Park to file Pembina Institute Report on Municipal Infrastructure (8 November 2006) [Transcript Volume 3, lines 2434-2445]**.

Yesterday, the Friends of Rockwood Park requested leave of this Board to file a report on Municipal Infrastructure prepared by the Pembina Institute on behalf of Friends of Rockwood Park.

The report was filed with the Board on the 1st of November and they [Emera] objected to the late filing on the basis that it was filed with no previous advice to parties, that to admit the report at this late date would cause prejudice to Emera's ability to respond to the report and that the City of Saint John has indicated that it will not be active in this proceeding. And thus, the matter is irrelevant to the Board's consideration of Emera's Application.

The Board rules, as follows, regarding the admission of the report.

The Board is charged with determining whether a project is required by the present and future public convenience and necessity. It makes its decision in the Canadian public interest. To do so, the Board is required to assess the benefits and the burdens of the proposed project by identifying and weighing them and determining whether, on balance, the benefits outweigh the burdens or vice versa.

In the Board's view, the potential impacts of this proposed project, whether positive or negative on municipal infrastructure, fall within the possible benefits and burdens to be assessed.

The Board also notes that the creation of the report was contingent on receipted information from a third party, which information, as Mr. Ruffman indicates, and as supported under the references to the report on the last page of the report, was not received until just prior to the submission of the report.

For these reasons, the Board is prepared, in this instance, to admit the late filing of the Pembina Report prepared for the Friends of Rockwood Park. In so doing, the Board also notes the following.

While support or opposition to a proposed project may inform the assessment of the benefits or burdens, it does not constitute in and of itself, a burden or benefit. Nor does support or opposition remove the requirement for the Board to consider any particular benefit or burden; so, the Board view it as a relevant consideration.

Given the late date of the introduction of this evidence, the Board advises that if appropriate witnesses are not present to be cross-examined on this evidence, should the request be made or such cross-examination, this may reduce the weight the Board may assign to this evidence.

As always, any party is entitled to present final argument about the weight to be afforded any given piece of evidence.

In addition, the Board is prepared to allow Emera significant latitude to address this evidence as part of its reply evidence towards the end of the oral Hearing, should Emera determine some reply is necessary.

Furthermore, should the Friends of Rockwood Park pose questions regarding this evidence to Emera's first Panel, the Board would entertain request by Emera for additional time to respond to this evidence, should such a request be made.

Board Ruling on Dr. Thomas's Request to Revisit the Scope of the Project (9 November 2006) [Transcript Volume 4, lines 5409-5427]

Dr. Thomas seeks to revisit the scope of the Brunswick Pipeline project to include the Canaport LNG Terminal in concert with the proposed Brunswick Pipeline to form one project as a whole to be considered under CEAA.

Emera's counsel, Mr. Smith objects on the basis that the Board in its capacity as a responsible authority under the Canadian Environmental Assessment Act has already determined with other responsible authorities the scope of the Brunswick Pipeline and the cumulative effects that can be considered.

On June 23rd, 2006, Exhibit A-3, the Board determined the scope of the Brunswick Pipeline project. On that date the Board also set out that cumulative effects including the Canaport LNG Terminal and tanker traffic could still be considered to the extent that those effects are relevant as cumulative effects that are likely the result from the project in combination with other projects or activities that have been or will be carried out.

In a subsequent ruling addressing an outstanding information request dated the 21st of September, 2006 Exhibit A-27 the Board set out the process for cumulative environmental effects assessment. The Board takes this opportunity to reiterate how this process works. The approach to accumulative effects assessment reflected in Guide A, Section A.2.6 of the National Energy Board's filing manual is to undertake the following sequential steps.

One, identify the potential effects for which residual effects are predicted for the project being assessed. Residual effects are those which would still exist after any mitigation is applied.

Two, for each biophysical element where residual effects are identified, determine the spatial and temporal boundaries that will be used to assess the potential cumulative effects.

Three, identify other projects and activities that have occurred or are likely to occur within the residual effects boundaries. And identify whether those projects and activities will produce effects on the biophysical element within the identified boundaries.

Four, consider whether the effects in three as just identified act in combination with the project's residual effects and if so include those projects or activities in the cumulative effects assessments.

And then five, analyze the cumulative effects of the proposed project in combination with other projects and activities for each biophysical element.

This includes considering the residual effects of the proposed project in combination with the effects of other projects and activities and considering whether the proposed project is incrementally responsible for adversely affecting a biophysical element beyond an acceptable point, for example threshold.

The manual also states that the level of effort and scale of the cumulative environmental effects assessment should be appropriate to the nature of the project under assessment, its potential residual effects and the environmental in socioeconomic setting.

The Board also wishes to emphasize that one of the purposes of the Canadian Environmental Assessment Act as set out in paragraph 4(1)(b.1) is to ensure that responsible authorities carry out their responsibilities in a coordinated manner with a view to eliminating unnecessary duplication in the environmental assessment process.

As noted in the Board's June 23rd, 2006 letter the Canaport LNG Terminal including the LNG tanker traffic has already undergone an environmental assessment by Federal authorities under the CEAA Act and by provincial authorities. That assessment is publicly available on CEAA's online registry. Therefore in carrying out its cumulative environmental effects assessment of the Brunswick Pipeline the Board must ensure that it is not being duplicative of environmental assessment processes already undertaken.

And that it is the potential residual effects of the Brunswick Pipeline being assessed. The Board's consideration of other projects is only in the context of whether those other projects have effects that have the potential to act in combination with the Brunswick Pipeline's residual effects.

Further the nature of the Brunswick Pipeline project and its potential residual effects also inform the level of effort and scale of the cumulative effects assessment.

It is within this context that the Board can consider LNG Terminal or LNG tanker traffic to the extent that they act in combination with any residual effects of the Brunswick Pipeline.

The Board is of the view that Dr. Thomas' line of question does not fall within this context. Furthermore, Dr. Thomas' concern with respect to the EIS completed for the LNG Terminal cannot be addressed in this proceeding. The Board was not an RA for that project.

In addition the Board reiterates its comments on the scoping document that assessment of a project under the CEAA Act is to occur at the proposal stage. The environmental assessment for that facility has been completed. This is not the appropriate forum for Dr. Thomas to challenge the adequacy of the LNG Terminal EIS.

As a result the Board upholds Mr. Smith's objection to Dr. Thomas' questioning and we will hear from Mr. Court again beginning tomorrow at 9:00 a.m.

Board Ruling on Questioning about Alternative Means (16 November 2006) [Transcript Volume 10, lines 14866-14878]

Yesterday, Mr. Sauerteig asked the Board to consider and allow him to continue cross-examining Emera's Panel No. 1 about his counter-proposal to the marine route that Emera examined in the course of making its decision to apply for the preferred route in its application.

The grounds Mr. Sauerteig relies on to bring this motion are that this marine crossing was an important part of his written intervention and that he has not been afforded sufficient opportunity to test the evidence adduced by Emera regarding the marine route alternatives.

Mr. Sauerteig also argued that no objections to this line of investigating Emera's application to the National Energy Board were raised before November 13, 2006.

Mr. Sauerteig further argued that according to Item 1.8.6 of Emera's application to the NEB, this marine crossing was considered but rejected for reasons which Mr. Sauerteig intended to show in the course of his cross-examination were either wrong or overstated.

Mr. Sauerteig states that this makes this aspect of Emera's application to the NEB suspect and that he was, until his questioning was halted, in the process of disproving most, if not all, of Emera's reasons listed in his application for rejecting this marine crossing.

As the Board has set out in previous applications for review during this hearing, Rule No. 44 of the NEB Rules of Practice and Procedure, requires that an application for review of a Board decision identifies sufficient grounds to raise doubt as to the correctness of that decision or order, including an error of law or jurisdiction, changed circumstances or new facts which have arisen, or facts that were not placed in evidence in the original decision, and were then not discoverable by due diligence.

The Board has not persuaded that grounds have been identified to raise doubt as to the correctness of the Board's request to have Mr. Sauerteig move on to another line of questioning.

As a result, Mr. Sauerteig's application for review is denied.

While the Board could end the matter here and -- will take this opportunity to explain that it is incumbent upon a project proponent to demonstrate under the Canadian Environmental Assessment Act that the proponent has considered alternative means of carrying out its proposed project that are technically and economically feasible.

The Board has throughout these proceedings permitted cross-examination within the scope set out under CEA. In this instance, Emera has filed evidence that it has considered the marine route as an alternative means to the preferred corridor for which it now applies.

It is the appropriateness of the preferred corridor that Emera asks the Board to adjudicate, not the alternative means such as the marine route.

In deciding whether to grant or deny Emera's application, the Board must be satisfied with Emera's evaluation of alternative means, as set out in the Canadian Environmental Assessment Act. Should the Board be satisfied with Emera's evaluation of alternative means under that act, the Board is then only able to judge the appropriateness of the preferred corridor, as applied for by Emera.

The Board points out that in the argument phase of this hearing, parties are free to argue about the adequacy of the alternative means Emera has considered under the Canadian Environmental Assessment Act, including the technical and economic feasibility of those alternative means, and that parties can also argue the adequacy of the preferred route and the general land requirements as set out in the list of issues.

Board Ruling on Questioning about Alternatives to the Project (17 November 2006) [Transcript Volume 11, lines 17126-17136]

The Board has heard a line of questioning from Anadarko and an objection to the proposed line of questioning by Emera and Repsol.

In responding to these objections, the Board is of the view it would also be helpful for parties to set out a framework for consideration of relevant issues in this proceeding.

The Board is here to hear evidence concerning the benefits and burdens of the applied-for Brunswick Pipeline Project, as currently framed. As a result, exploration of these benefits and burdens of this project by parties to this proceeding is permitted.

Areas such as the impact this project may have on current pipelines, other current or reasonably contemplated projects, current tolls or supply and demand market issues are, therefore, open to be explored.

Need for the pipeline can be fully explored, including the issue of whether this project, as currently framed, could be considered a bypass to existing or reasonably contemplated pipeline facilities.

However, exploration of the benefits or burdens of a project, which is not before the Board, is outside the scope of this proceeding; that is, what the benefits would be of a different project, built by a different company, involving altering of the M&NP Canada System to transfer the supply from Canaport, the cost for doing so and the benefits or burdens of such other project on other matters, such as the ability of Nova Scotia's future potential supply sources to access the market, are outside the scope of this proceeding.

The speculative impact on the levels of tolls, on M&NP Canada, if such a project were to be constructed are also not of probative value to the Board, in assessing the benefits and burdens of this Brunswick Pipeline Project.

There is no evidence submitted that any such speculative or hypothetical project would be constructed.[32] Spending time exploring these speculative and remote alternative projects is not of sufficient probative value to the Board, in determining whether this project is in the present and future of public convenience and necessity.

Alternatives to the project raised, in the context of CEAA, should not be used to delve into a detailed economic analysis of the benefits and burdens of that alternative, as it is outside of the scope of the Board's considerations under CEAA.

Accordingly, a discussion of whether an alternative or hypothetical project, which is not proposed before the Board, and how that hypothetical project could potentially serve incremental natural gas supply for the region, or affect future tolls on other pipelines is not sufficiently tied to an assessment of the benefits and burdens of the Brunswick Pipeline Project, and will not be permitted.

With this direction, Mr. Roth, you may ask any further questions that fall within this framework.

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Appendix VII

National Energy Board Environmental Assessment Report

NATIONAL ENERGY BOARD ENVIRONMENTAL ASSESSMENT REPORT

Pursuant to the *Canadian Environmental Assessment Act*

Brunswick Pipeline Project

April 2007

NATIONAL ENERGY BOARD ENVIRONMENTAL ASSESSMENT REPORT

Pursuant to the *Canadian Environmental Assessment Act*

Brunswick Pipeline Project

Applicant Name: Emera Brunswick Pipeline Company Ltd. (EBPC)

Preliminary Submission Date: Project Description received 6 January 2006.

Application Date: 23 May 2006.

CEA Act Registration Date: 29 March 2006.

CEA Registry Number: 06-03-17667.

National Energy Board (NEB or Board) File Number:
OF-Fac-G-E236-2006-01 01 (3200-E236-1)

CEA Act Law List Trigger: Section 52 of the *National Energy Board Act*.

Date of Environmental Assessment

Report: April 2007.

SUMMARY

The Brunswick Pipeline Project (the Project) consists of a natural gas transmission pipeline from the Canaport-liquefied natural gas (LNG) Terminal at Mispec Point, near Saint John, New Brunswick (NB), to an export point at the Canada-United States (US) border. The Project would include a pipeline of approximately 145 km, about 35 km of which would be within the Saint John area, as well as a number of associated facilities.

The federal Minister of the Environment approved the National Energy Board's (NEB or Board) use of its own public hearing process for assessing the environmental effects of the Project as a substitute for an environmental assessment (EA) by a review panel under the substitution provisions of the *Canadian Environmental Assessment Act* (CEA Act). This Report sets out the rationale, conclusions and recommendations of the Board in relation to its review of the Project under the CEA Act and includes a discussion of recommended mitigation measures and follow-up programs. A number of recommendations were made by the Board, some of which are in this summary. The remaining recommendations are included in section 9 of the EA and are discussed throughout the Report. If the Project proceeds to regulatory approval, the Board would recommend that these be included as conditions to any Certificate issued by the Board.

This Report also provides a summary of comments received from the public. If the Project proceeds to regulatory consideration, it will be considered under the *National Energy Board Act* (NEB Act) for a Certificate of Public Convenience and Necessity, and a decision and Reasons for Decision will be issued under that Act.

The Board considered the evidence of Emera Brunswick Pipeline Company Ltd. (EBPC or the Proponent), Intervenors and Government Participants, and public comments received during its review of the Project. The Board has determined that, provided all commitments made by EBPC in its application and undertakings during the GH-1-2006 proceeding are upheld, and the Board's recommendations are implemented, the Project is not likely to result in significant[33] adverse environmental effects. The Board therefore recommends that the Project be allowed to proceed to regulatory and departmental decision-making as long as the recommendations in this Report are made part of the requirements of any Certificate issued by the NEB.

The Board was asked by Intervenors to include in its review of the Project the environmental effects of the Canaport - LNG Terminal. However, the Board ruled that the Canaport - LNG Terminal or the LNG tanker activity was beyond the scope of the project for the EA of the Project. The Board notes that the environmental effects of the Canaport[TM] Terminal were considered in the environmental assessment conducted by FAs under the CEA Act and by the Province of New Brunswick under provincial environmental assessment regulations. The Board therefore limited its review of the Terminal and tanker traffic

to the extent relevant as cumulative environmental effects likely to result from the Project in combination with other projects or activities that have been or will be carried out.

Purpose of, Need for and Alternatives to the Project

The primary purpose of and need for the Project, according to EBPC, is to provide the necessary new infrastructure to transport natural gas from the Canaport-LNG Terminal, currently being constructed near Saint John, to markets in Maritimes Canada and the Northeastern US. Alternatives to the Project considered included transportation of the LNG supply by ship, truck or train, but such options did not compare to the cross-border pipeline option in terms of economic feasibility and environmental appropriateness. Further, the existing Saint John Lateral pipeline would not be a technically or economically viable option for meeting the Project's objectives.

Other parties to the hearing argued that expansion of the Maritimes & Northeast Pipeline (M&NP) System would be a safe and economically feasible alternative to the Project and that EBPC's consideration of alternatives to the Project was inadequate.

The Board considered the alternatives and concluded that the need for and the purpose of the Project, for the purpose of the CEA Act EA, are to be established from the perspective of EBPC. The alternatives to the Project to be considered in this EA are to be informed by the purpose of and need for the Project. The Board is satisfied that it was reasonable for EBPC to conclude that the alternatives to the Project it considered, that would meet the purpose of and need for the Project from the Proponent's perspective, were not technically and economically feasible, and therefore are not viable alternatives to the Project. The information provided during the hearing supports EBPC's conclusion.

Alternative Means

EBPC considered several alternative means, including alternative corridors, in selecting its preferred route for the Project. Alternative corridors were considered for both the urban and rural portions of the route, and included a marine crossing of the Bay of Fundy as one of the urban alternatives.

Intervenors argued that EBPC's dismissing of the marine route option was not adequately supported, that EBPC misrepresented or over-estimated the difficulties, costs, or risks associated with the marine crossing, and that a marine crossing would be safer than the proposed route through the City of Saint John.

The Board also considered evidence related to alternative construction methods and size of pipe. The Board finds that EBPC provided sufficient evidence regarding its consideration of a marine crossing of the Saint John Harbour, and that this evidence underwent broad questioning by parties to the hearing. EBPC's evidence was supported by credible expert witnesses and EBPC's conclusions with respect to the feasibility of a marine crossing were reasonable, based on the evidence adduced.

The Board concludes that EBPC provided adequate information on alternative corridors and construction methods that are technically and economically feasible for the Board to consider these alternative means and their environmental effects. The rationale provided by EBPC for rejecting the alternative means it considered, as well as the Intervenors' proposed alternative means, is reasonably founded in the evidence, and supports, among other things, the selection of the preferred corridor, construction methods and size of pipe.

Public Participation

Seventy-two parties registered as Intervenors and three parties registered as Government Participants in the NEB's hearing process. In addition, 184 letters of comment from the public were entered onto the record and oral statements were provided by 19 individuals, two of whom represented organizations in Saint John. The Board has taken into consideration comments from the public in assessing the Project.

Various participants expressed dissatisfaction with the public consultation program carried out by the Project Proponent. An evaluation of EBPC's consultation program undertaken pursuant to the guidelines set out in the NEB's Filing Manual, including but not limited to consultation activities related to environmental matters, will be included in the Board's Reasons for Decision issued pursuant to its mandate under the NEB Act. The evaluation in the Reasons for Decision will provide a more comprehensive assessment of the consultation program, including consideration of the comments and concerns raised by participants. While recognizing that certain areas could have been improved, the Board is satisfied that EBPC and the NEB public hearing process have met the requirements for public participation under the CEA Act.

Environmental Effects on the Biophysical Environment

Certain potential adverse environmental effects on the biophysical environment generated particular public concern. These potential adverse environmental effects involved non-standard mitigation measures, monitoring or follow-up programs, or required the implementation of an issue-specific recommendation, and included effects on Species at Risk and Species of Conservation Concern, wetlands and Rockwood Park, as well as effects from unauthorized access to the right of way (RoW) and acid rock drainage. The Board made recommendations with respect to managing biophysical environmental effects, including:

* the development of a site-specific environmental protection plan (EPP) demonstrating evidence of consultation with relevant regulatory authorities;
* the development of an access management plan demonstrating consultation with stakeholders; and
* the design and implementation of follow-up programs related to fish and fish habitat, wetlands, access management, and reclamation of Rockwood Park.

Environmental Effects on the Socio-Economic Environment

Certain potential adverse environmental effects on the socio-economic environment generated particular public interest. These involved non-standard mitigation measures, monitoring or follow-up programs, or required the implementation of an issue-specific recommendation, and included effects on recreational use of Rockwood Park, on heritage resources, and on the current use of lands and resources for traditional purposes by Aboriginal Persons as well as effects from noise. The Board made recommendations with respect to managing socio-economic environmental effects, including:

* an update on the recommendations identified in EBPC's Traditional Ecological Knowledge (TEK) Study;
* conducting archaeological studies and associated monitoring; and
* the design and implementation of follow-up programs related to horizontal directional drill noise management.

Accidents and Malfunctions

Many of the comments received from the public regarding this Project were concerns about the consequences of a pipeline leak or rupture and potential associated fire, concerns about access to communities in the event of an emergency and the capacity of first responders to handle an emergency.

EBPC's proposed Environmental Management Framework includes programs to avoid a pipeline leak or rupture. In the event of a leak or rupture, EBPC has set out the programs it would have in place to respond to emergencies. These programs would be aimed at minimizing the negative effects of a leak or rupture, and include cooperation with first responders and consideration of access to communities.

In this Report, the Board makes specific recommendations regarding the development of an Emergency Procedures Manual and the conduct of emergency response exercises. Given the Environmental Management Framework and the Board's recommendations, the Board is of the view that it is unlikely that the Project would result in a pipeline leak or rupture leading to a fire. EBPC's Emergency Preparedness and Response Program would provide a means of preparing to respond in the event of a leak or rupture. Therefore, the Board finds that the proposed Project would not likely cause significant adverse effects as a result of an accident or malfunction.

Cumulative Environmental Effects

Concerns were expressed regarding the consideration of the Canaport[TM] LNG Terminal and associated tanker activity in the cumulative effects assessment. Concerns were also expressed regarding cumulative effects resulting from greenhouse gas emissions and on air quality.

The Board concludes that given the nature of the Project, EBPC's proposed mitigation measures, the recommendations of the Board, and the limited extent of any residual effects, that significant adverse cumulative effects of the Project are unlikely.

Need for and Requirements of Follow-up Programs under the CEA Act

The Board considered the need for and requirements of follow-up programs in the EA. Specific areas of follow-up that would be required by the Board include: fish and fish habitat, wetlands, access management, horizontal directional drill noise management, and reclamation of Rockwood Park.

Ongoing Commitments

The Board notes EBPC's commitment to its ongoing consultation program. The Board expects that EBPC would continue consulting with potentially affected stakeholders prior to, during and after construction of the pipeline, and over the lifetime of the Project. Some examples of ongoing consultation are the commitments by EBPC for continuing education programs for first responders and public awareness programs.

Comments on the Substitution Process

The NEB wishes to acknowledge the effort of its federal partners toward streamlining the regulatory process while maintaining the breadth and quality of the environmental assessment. The hearing process, as an integrated process considering environmental assessment as well as other issues relevant to the public interest, allowed the Board to hear from a broad spectrum of participants on a wide range of issues. The input was significant to the Board in its deliberations.

The success of this pilot project was made possible through the commitment and cooperation of the CEA Agency, federal departments involved in the environmental assessment as well as the participation of the people of New Brunswick who shared their views with the Board through written and oral presentations. The NEB also recognizes the cooperation of EBPC and its consultants.

The Board sincerely thanks all who participated in or otherwise supported this hearing and in particular the Board thanks the people of New Brunswick.

Information Sources

The analysis for this environmental assessment report is based on evidence submitted to the NEB by EBPC within the GH-1-2006 proceeding. The analysis also considers the comments received from the public (summarized in Section 5.5) and comments or recommendations received from Responsible Authorities and Federal Authorities (summarized in Appendix 1).

To view this information please refer to the NEB website at www.neb-one.gc.ca. Select "Regulatory Documents", then "Gas" under the "Facilities" list, then "Emera Brunswick Pipeline Company Ltd", and finally "2006-05-02 - Application for the Brunswick Pipeline Project (GH-1-2006)".

For more details on how to obtain documents, please contact the Secretary of the NEB at the address specified in the Section 10.0 of this Report.

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LIST OF ABBREVIATIONS

Al: aluminum

Anadarko: Bear Head LNG Corporation, Anadarko Canada LNG Marketing, Corp. and Anadarko LNG Marketing, LLC

ARD: acid rock drainage

As: arsenic

ATV: all-terrain vehicle

Board: National Energy Board

CCME: Canadian Council of Ministers of the Environment

CEA Act: *Canadian Environmental Assessment Act*

CEA Agency: Canadian Environmental Assessment Agency

CEPA 1999: *Canadian Environmental Protection Act 1999*

CO: carbon monoxide

CO[subscript 2]: carbon dioxide

CO[subscript 2]e/year: carbon dioxide equivalents per year

COSEWIC: Committee on the Status of Endangered Wildlife in Canada

CSA: Canadian Standards Association

Cu: copper

DAS: Disposal at Sea

DFO: Department of Fisheries and Oceans Canada

EA: environmental assessment

EBPC, the Applicant, or the Proponent: Emera Brunswick Pipeline Company Ltd.

EC: Environment Canada

Eldridge-Thomases: Dr. Leland Thomas and Ms. Janice Eldridge Thomas

EMO: emergency management organizations

EPP: environmental protection plan

EPZ: emergency planning zone

ERP: field emergency response plan

ESEA: environmental and socio-economic assessment

FA: federal authority

Fe: iron

FORP: the Friends of Rockwood Park

GhG: greenhouse gases

ha: hectare

HADD: harmful alteration, disturbance or destruction

HC: Health Canada

HDD: horizontal directional drill

IPL: international power line

km: kilometre

kPa: kilopascal

LNG: liquefied natural gas

m: metre

M&NP: Maritimes & Northeast Pipeline Management Ltd.

mm: millimetre

Mn: manganese

MMBtu: million British thermal units

NB: New Brunswick

NBDELG: New Brunswick Department of Environment and Local Government

NBDNR: New Brunswick Department of Natural Resources

NBDOE: New Brunswick Department of Environment

NB ESA: *New Brunswick Endangered Species Act*

NB Power: New Brunswick Power

NEB: National Energy Board

NEB Act: *National Energy Board Act*

NPS: nominal pipe size

NRCan: Natural Resources Canada

OPR: *Onshore Pipeline Regulations, 1999*

OPS: operational policy statement

Pembina: the Pembina Institute

ppb: parts per billion

(the) Project: the proposed Brunswick Pipeline Project

psig: pounds per square inch, gauge

RA: responsible authority

Repsol: Repsol Energy Canada Ltd.

RoW: right of way

SARA: *Species at Risk Act*

SJFD: Saint John Fire Department

SJL: Saint John Lateral

TEK: Traditional Ecological Knowledge

UNBI: Union of New Brunswick Indians

US: United States

WAWA: Watercourse and Wetland Alteration Permit

Zn: zinc

ug/m[superscript 3]: microgram per cubic metre

GLOSSARY

alternative means: the various ways that are technically and economically feasible that the project can be implemented or carried out

alternatives to: functionally different ways to meet the project need and achieve the project purpose

archaeological and heritage resources: any physical remnants found on top of and/or below the surface of the ground that inform us of past human use of and interaction with the physical environment

cumulative environmental effects: environmental effects that are likely to result effect from the Project in combination with projects or activities that have been or will be carried out (defined in the CEA Act)

construction: construction includes all activities required to construct the Project, including all clearing activities

deer wintering area: an area currently used by deer during winter, including adjacent stands that have a potential for providing shelter and food on a long-term ([greater than]50 years) basis

dry crossing: installation of the pipeline under a watercourse involving isolation of the flowing water from the pipeline trench in the watercourse by damming of the water and diverting the flowing water around the construction zone using water pumps or culverts

environmental effect: in respect to a project, (a) any change that the project may cause in the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species as those terms are defined in section 2(1) of the *Species at Risk Act*, (b) any effect of any change referred to in paragraph (a) on health and socioeconomic conditions, on physical and cultural heritage, the current use of lands and resources for traditional purposes by Aboriginal persons, or any structure, site or thing that is of historical, archaeological, paleontological or architectural significance, or (c) any change to the project that may be caused by the environment (defined in the CEA Act)

Endangered: under SARA, wildlife species listed as endangered are facing imminent extirpation or extinction

Environmentally Significant Area: an area identified by the Nature Trust of New Brunswick as having a rich area diversity of species or special features (e.g., rare plants or animals) federal authority (FA) a) a Minister of the Crown in right of Canada, (b) an agency of the Government or other body established by or pursuant to an Act of Parliament that is ultimately accountable through a Minister of the Crown in right of Canada to Parliament for the conduct of its affairs, (c) any department or departmental corporation set out in Schedule I or II to the Financial Administration Act, and (d) any other body that is prescribed pursuant to regulations made under paragraph 59(e) (defined in the CEA Act)

follow-up program: a program for verifying the accuracy of the environmental assessment of a project, and determining the effectiveness of any measures taken to mitigate the adverse environmental effects of the project (defined in the CEA Act)

greenhouse gas: radiative gases in the earth's atmosphere which absorb long-wave heat radiation from the earth's surface and re-radiate it, thereby warming the earth (e.g., carbon dioxide and water vapour)

grubbing: the removal of roots and stumps after clearing activities

horizontal directional drill: a river, railroad, highway, shoreline and marsh crossing technique used in pipeline construction in which the pipe is installed under specified no-dig areas at depths usually greater than conventional crossings. An inverted arc-shaped hole with two sag bends is drilled beneath the no-dig area and the preassembled pipeline is pulled through it

hydrostatic test: a test in which the pipeline is filled with water and pressurized to demonstrate that no defect (e.g., weld integrity) is present that would cause an immediate failure at the operating pressure

induced potential: voltage induced on a pipeline from high voltage overhead powerlines in close proximity

launcher/receiver site: facilities used to launch and receive pipeline internal inspection and cleaning equipment

Mature Coniferous Forest Habitat: stands with the structural and spatial attributes required by old forest-dependent species such as American marten (*Martes americana*)

May be at risk: species or populations that may be at risk of extirpation or extinction, and are therefore candidates for a detailed risk assessment (designated by NBDNR)

meter station: a facility to monitor natural gas flow in pipeline systems (i.e., gas entering and leaving the pipeline system); meter stations may also allow for monitoring of natural gas quality

mitigation: in respect of a project, the elimination, reduction or control of the adverse environmental effects of the project, and includes restitution for any damage to the environment caused by such effects through replacement, restoration, compensation or any other means (defined in the CEA Act)

need for the project: the problem or opportunity the project is intending to solve or satisfy

purpose of the project: what is to be achieved by carrying out the project

Regionally Endangered: under the NB ESA, any indigenous species of fauna or flora threatened with imminent extirpation throughout all or a significant portion of its range in the Province and designated by regulation as regionally endangered

responsible authority (RA): in relation to a project, a federal authority that is required pursuant to subsection 11(1) of the CEA Act to ensure that an environmental assessment of the project is conducted (defined in the CEA Act) right of way: the area which must be cleared (vegetation), crossed (watercourse), or developed (land) for the purpose of installing a pipeline

Sensitive: species which are not believed to be at risk of extirpation or extinction, but which may require special attention or protection to prevent them from becoming at risk (designated by NDNR)

Species at Risk: all species listed in Schedule 1 of the SARA as "extirpated", "endangered", or "threatened", or listed by the NB ESA as "endangered" or "regionally endangered"

Species of Conservation Concern: species not under the protection of the SARA or the NB ESA (i.e., listed in the SARA but not as "extirpated", "endangered", or "threatened" in Schedule 1; listed as "species of special concern" within Schedule 1 of the SARA; or ranked as "S1", "S2", or "S3" by the Atlantic Canada Conservation Data Centre and also ranked as "at risk", "may be at risk", or "sensitive" by NBDNR)

Species of Special Concern: under SARA, wildlife species that may become a threatened or an endangered species because of a combination of biological characteristics and identified threats

Threatened: under SARA, wildlife species that are likely to become an endangered species if nothing is done to reverse the factors leading to its extirpation or extinction

Watershed Protection Area: Area in which there are limits to land use that may pose a risk to surface water supplies within the watershed

wet crossing: installation of the pipeline under a watercourse by constructing directly through the undiverted flow of the watercourse

1.0 SUBSTITUTION PROCESS FOR THE ENVIRONMENTAL ASSESSMENT OF THE BRUNSWICK PIPELINE PROJECT

1.1 Environmental Assessment Coordination

The National Energy Board (NEB or the Board) received a project description for the proposed Brunswick Pipeline Project (the Project) from Maritimes & Northeast Pipeline Management Ltd. (M&NP) on 6 January 2006. The NEB then notified potential federal and provincial authorities about the Project, pursuant to the *Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements* under the *Canadian Environmental Assessment Act* (CEA Act).

The NEB, the Department of Fisheries and Oceans Canada (DFO), and Transport Canada are responsible authorities (RAs) pursuant to the CEA Act for the environmental assessment (EA) of the Project. Environment Canada (EC) and the Canadian Transportation Agency identified themselves as possible RAs for the EA.

The potential federal permits and authorizations that triggered the CEA Act and would or may be necessary for the Project are:

* a Certificate of Public Convenience and Necessity issued pursuant to section 52 of the *National Energy Board Act* (NEB Act);

* authorization by DFO pursuant to subsection 35(2) and/or section 32 of the *Fisheries Act*;
* authorization by Transport Canada under section 5(1) or 6(4) of the *Navigable Waters Protection Act* or section 108 and 109 of the NEB Act;
* authorization by EC for disposal at sea pursuant to the *Canadian Environmental Protection Act* (CEPA 1999); and
* authorization by the Canadian Transportation Agency under sub-section 101(3) of the *Canada Transportation Act.*

To assist in the EA process, Natural Resources Canada (NRCan) and Health Canada (HC) provided expert advice in relation to the Project.

Comments, recommendations and specialist advice received by RAs and federal authorities (FAs)[34] during the process have been addressed in relevant sections of this EA Report and are summarized in Appendix 1.

The Project must be registered as an undertaking pursuant to the New Brunswick *Environmental Impact Assessment Regulation* under the New Brunswick *Clean Environment Act*. The New Brunswick Department of Environment (NBDOE) administers this regulation and requires that an environmental impact assessment be carried out and approved by the Government of New Brunswick before the Project can proceed.

The NEB coordinated the EA process with all involved federal and provincial departments. The Canadian Environmental Assessment Agency (the CEA Agency) was also involved in coordination activities.

1.2 Process

Based on M&NP's January 2006 project description mentioned above, the NEB determined on 16 February 2006 that the Project required a comprehensive study pursuant to the CEA Act *Comprehensive Study List Regulations*. On 16 March 2006, the NEB subsequently requested, on behalf of the RAs, that the federal Minister of the Environment refer the Project to panel review. In the same letter, the NEB requested that the panel review be conducted by the NEB under the substitution provisions of the CEA Act. On 3 May 2006, the Minister of the Environment referred the Project to panel review and approved the NEB's request for substitution pursuant to subsection 43(1) of the CEA Act.

The substitution provisions of the CEA Act allow an FA to use its own process for assessing the environmental effects of a project as a substitute for an EA by a review panel under the CEA Act. In this case, the Minister's approval allowed the NEB's public hearing process to substitute for an EA by a review panel under the CEA Act. The requirements for the substituted process were set out in correspondence among the CEA Agency, the NEB, and the Minister of the Environment, attached as Appendix 2.

In a letter dated 14 March 2006, M&NP advised the NEB and the CEA Agency that upon further review, the actual applicant for the Project may be a distinct special-purpose corporate entity. The identity and ownership of the entity may change, but the physical project would remain as described in the project description.

The NEB received an application for the Project on 23 May 2006 from Emera Brunswick Pipeline Company Ltd. (EBPC, the Applicant or the Proponent), as the new owner of the Project. The NEB released the hearing order for the NEB public hearing process on 9 June 2006. Hearing Order GH-1-2006 set out opportunities for participation in the process through letters of comment, oral statements or interventions. For FAs, or provincial agencies with an EA responsibility for the Project, the Hearing Order also offered the opportunity for participation as a Government Participant. Seventy-two parties registered as Intervenors and three parties registered as Government Participants in the process.

Based on the 6 January 2006 project description submitted by M&NP, the NEB released a draft EA Scoping Document for the Project on 5 May 2006 for public comment. Several comments on the draft document were received during the comment period, which closed on 7 June 2006. EBPC replied to the public comments on 12 June 2006. A summary of all comments received by the NEB on the draft document is included in Appendix 3.

After considering comments received on the Scoping Document, the NEB determined and released the scope of the EA on 23 June 2006 (Appendix 4). Based on the requirements of the CEA Act and the factors to be considered as set out in the Scoping Document, the EA includes a consideration of the following factors listed in paragraphs 16(1)(a) to (d) and subsection 16(2) of the CEA Act:

1. the environmental effects of the Project, including the environmental effects of malfunctions or accidents that may occur in connection with the Project and any cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out;
2. the significance of the effects referred to in paragraph 1;
3. comments from the public that are received during the public review;
4. measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project;
5. the purpose of the Project;
6. alternative means of carrying out the Project that are technically and economically feasible and the environmental effects of any such alternative means;
7. the need for, and the requirements of, any follow-up program in respect of the Project; and
8. the capacity of renewable resources that are likely to be significantly affected by the Project to meet the needs of the present and those of the future.

In accordance with paragraph 16(1)(e) of the CEA Act, the EA also includes a consideration of the following additional matters:

1. the need for the Project; and
2. alternatives to the Project.

During the public hearing process, referred to as the GH-1-2006 proceeding, the NEB obtained information from EBPC through both written and oral processes. Prior to the oral portion of the hearing, the Applicant, Intervenors and Government Participants had the opportunity to provide written evidence, and responded to information requests from the NEB and other parties on this evidence. In addition, 184 letters of comment from the public were entered onto the record for the GH-1-2006 proceeding.

The oral portion of the public hearing was held in Saint John, New Brunswick (NB) from 6 to 20 November 2006. EBPC presented five witness panels which were cross-examined by Intervenors and questioned by the Board. Intervenor witness panels were also available for cross-examination. Oral statements were provided by 19 individuals, two of whom represented organizations in Saint John. The written final argument portion of the hearing concluded on 22 December 2006. The entire NEB public hearing process allowed a variety of participants to provide their views on the Project - Intervenors, Government Participants, letter of comment writers and oral statement makers, including individuals, organizations and government representatives.

In the past, panel reviews under the CEA Act have often been integrated with the NEB's public hearing process under the NEB Act, as have EAs of projects undertaken at a screening or comprehensive study level. The hearing process used for this proceeding was very similar. The primary differences between a panel review carried out in an integrated manner with the NEB public hearing process and the current substituted process are:

* all panel members are members of the NEB in the substituted process; and
* the Project was quickly referred to a panel review and a substituted process as opposed to undergoing a more extended EA track decision process which would require a public consultation process on a proposed scope of the EA followed by the preparation and submission of a track recommendation report to the Minister of the Environment.

1.3 Environmental Assessment Report

In this EA Report, the Board sets out its rationale, findings, conclusions and recommendations, including any mitigation measures that should be implemented and the NEB's recommended follow-up programs should the Project be approved under the NEB Act. This Report also provides a summary of comments received from the public (see section 5.5). Once issued, this Report will be submitted to the Minister of the Environment and the RA Ministers for the preparation of the government response.

The NEB must await the government response to this EA Report and take this into consideration before making any decision under the NEB Act. The content of this Report and the government response will be considered in the Board's deliberations, but the conclusions reached in this Report do not dictate the outcome of the Board's regulatory decision under the NEB Act, as there are additional factors beyond those considered in the EA that the Board must consider under the NEB Act in order to determine whether the Project is in the present and future public convenience and necessity.

1.4 Participant Funding

The CEA Agency administered a Participant Funding Program to assist the participation by interested individuals and organizations in the environmental review of the Project. The independent funding committee assessed applications for funding and awarded a total of $135,900 to six parties. The funds were intended to assist recipients in reviewing the application and in preparing for and participating in EA portions of the GH-1-2006 proceeding.

2.0 DESCRIPTION OF THE PROJECT

EBPC described the Project as a stand-alone, separately-owned pipeline project. It is not integrated with the system owned and operated by M&NP in Canada. M&NP commenced development of the Project on a stand-alone basis, separate from the rest of its system. On 15 May 2006, M&NP transferred all of its rights and interests in the Project to EBPC. The Project as discussed in this Report is based on the evidence submitted by EBPC as the Applicant.

2.1 Project Maps

Figures 1 through 4 provide maps of the Project that are referred to in subsequent sections.

Figure 1

Preferred Corridor and Rockwood Park Variants -

Brunswick Pipeline Project

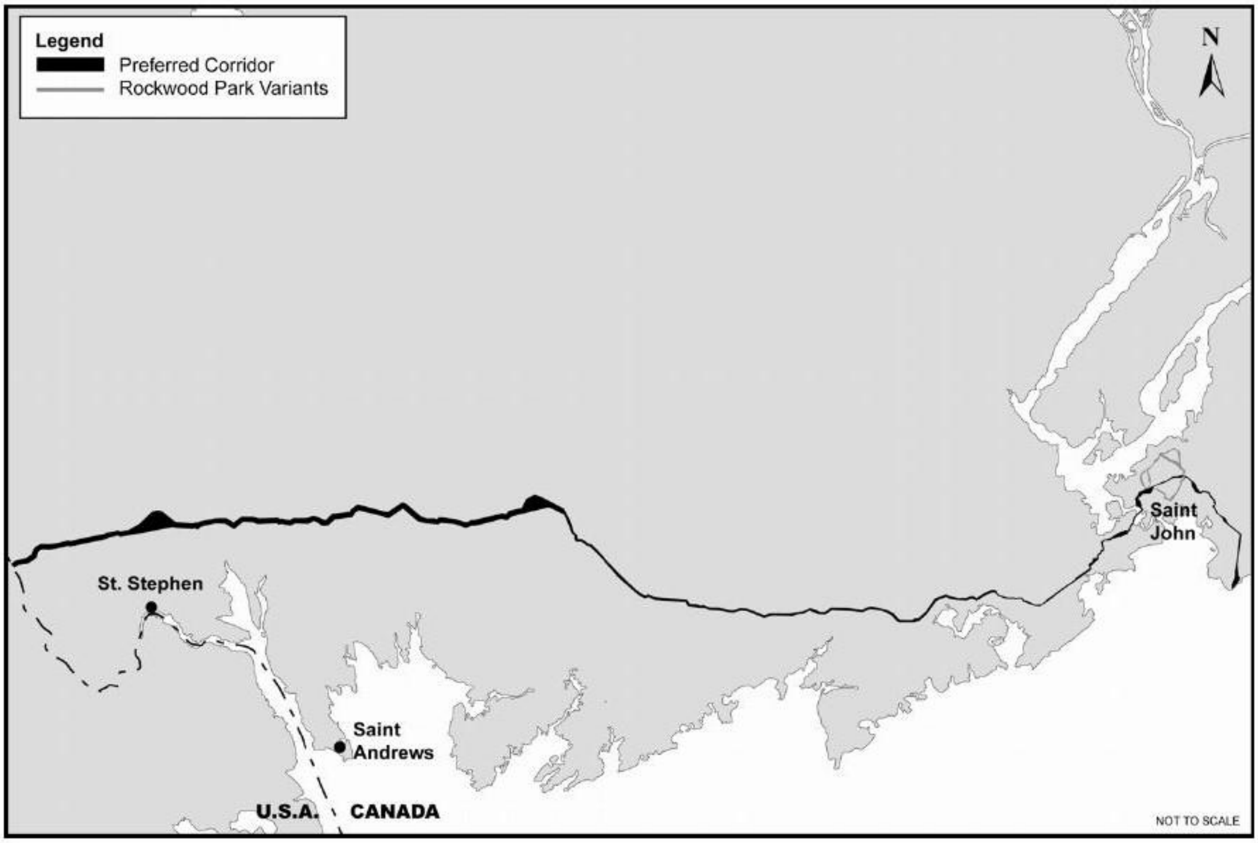


Figure 2

Proposed Pipeline Corridors - Preliminary

Evaluation of Proposed Pipeline Routes

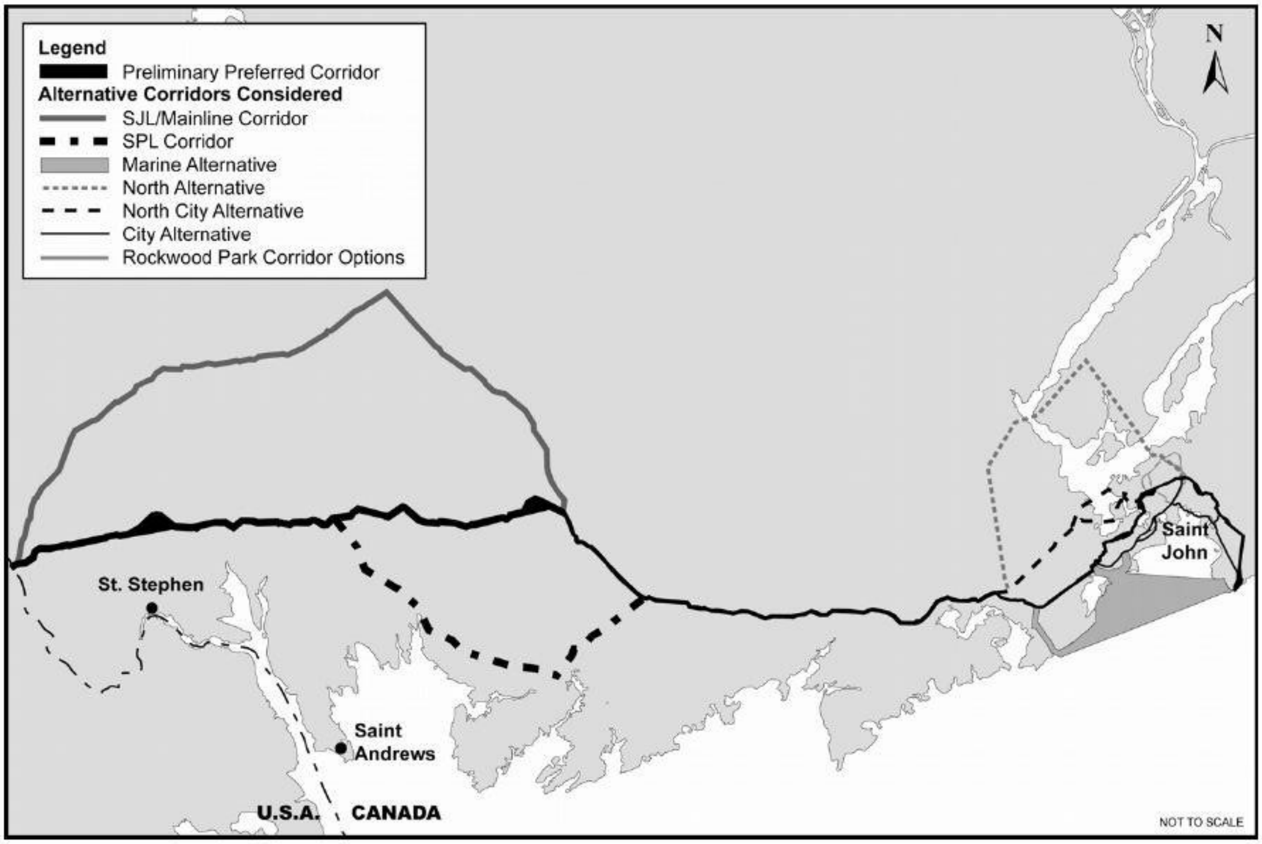


Figure 3

Proposed Urban Pipeline Corridors - Preliminary

Evaluation of Proposed Pipeline Routes

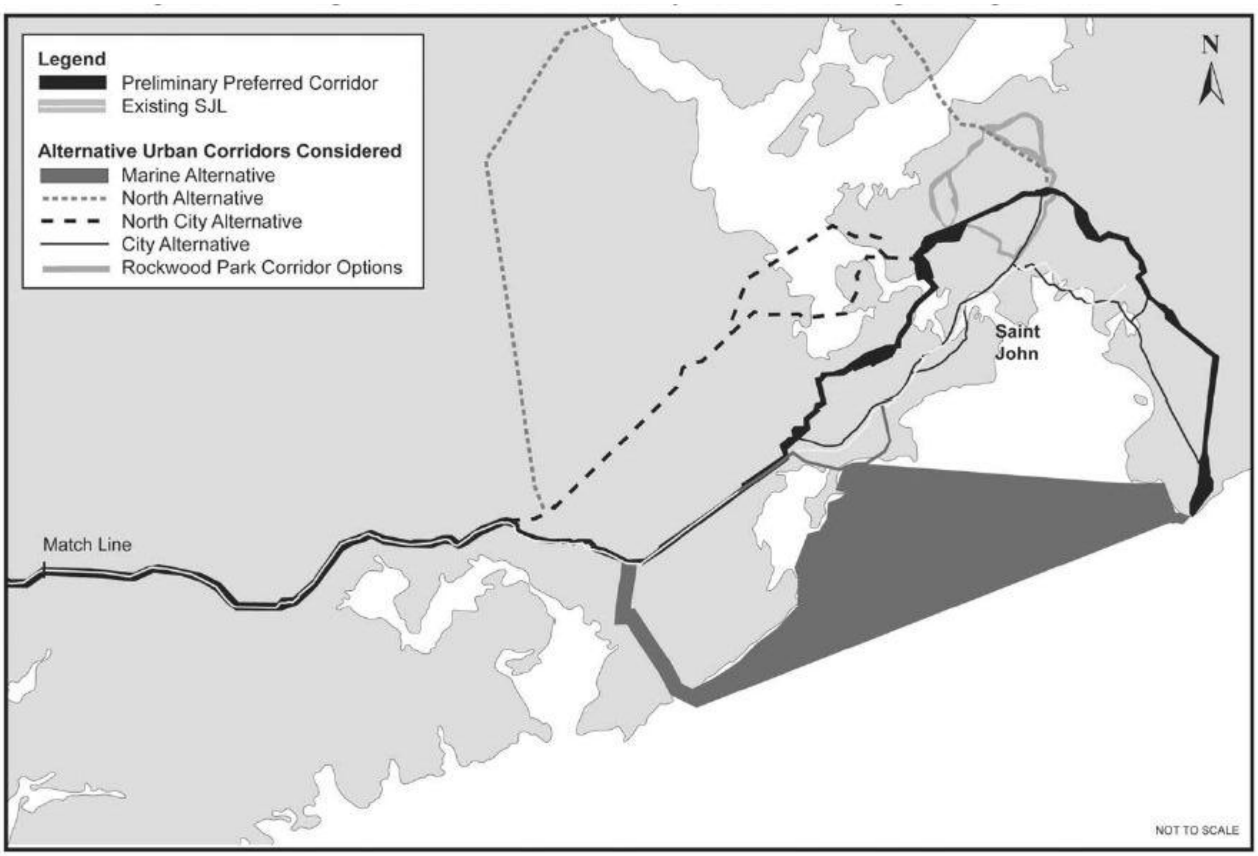
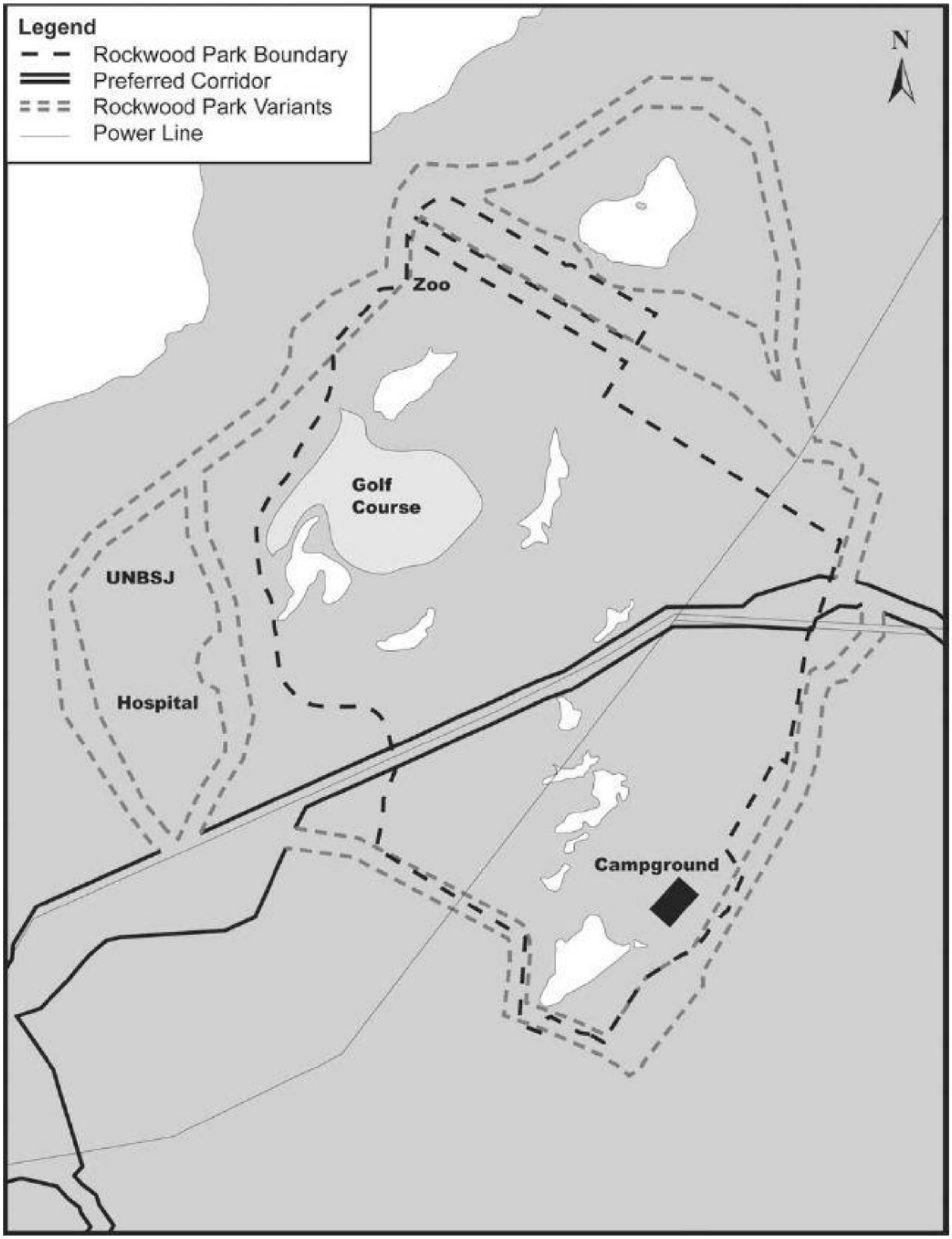


Figure 4

Rockwood Park Variants and Preferred Corridor



2.2 Project Components

The scope of the Project being assessed is in accordance with that outlined in section 2.1 of Appendix 4 - Environmental Assessment Scoping Document.

The Project consists of a natural gas transmission pipeline from the Canaport-liquefied natural gas (LNG) Terminal (currently under construction) at Mispec Point, near Saint John, NB, to an export point at the Canada-United States (US) border. EBPC submitted that the Project would include a pipeline of approximately 145 km, about 35 km of which would be within the Saint John area, as well as a number of associated facilities, including: six valve sites, a combined meter station and launcher site, and a combined valve and launcher/receiver site. The pipeline itself would be 762 mm (30 inches) in diameter and would operate at a maximum pressure of 9 930 kPa (1,440 psig).

The following description of the Project is based on the evidence submitted by EBPC.

The pipeline, the associated facilities and the required right of way (RoW) would be located within the preferred corridor shown in Figure 1.

During construction, work would be confined to the 30 m-wide RoW with additional temporary work areas required at watercourse and road crossings, and construction staging areas. For the purposes of this Report and the recommendations herein, the term "construction" includes all clearing activities.

RoW clearing would mostly be conducted during the winter months and the remainder of project construction would be completed during the summer and fall. However, EBPC anticipates that limited construction, other than clearing, would be conducted during the winter months. Where practicable, the Project RoW would parallel and overlap existing RoWs. Marshalling yards, storage areas and access roads to the RoW would also be required on a temporary basis. EBPC anticipates that existing roads could be used for access to the RoW and planned valve sites during the operation and maintenance phase of the Project.

No compressor stations are anticipated for the Project, as sufficient pressure for transporting the natural gas would be provided at the Canaport[TM] LNG Terminal. The entire pipeline system would be installed subsurface with the exception of valve sites (three in urban Saint John and three in rural areas), a combined meter station and launcher site (immediately outside of the Canaport[TM] LNG Terminal battery limits), and a combined valve and launcher/receiver site adjacent to line valve 63 on the existing Saint John Lateral (SJL) (off of the West Branch Road, Musquash). Each of the sites would require the installation of a permanent access road.

Valve sites would be fenced areas, approximately 20 m x 20 m, which would be locked and regularly inspected for safety and security. These sites would include:

* sectional valves with manual and remote control capability;
* blowdown capabilities;
* a small building approximately 2.4 m x 3.0 m to house electronic equipment; and
* power and telecommunications supply (e.g., satellite communications dish).

The combined meter station and launcher site would be a fenced and graveled area, approximately 50 m x 50 m, which would be locked and regularly inspected for safety and security. The meter station and launcher site would include:

* station inlet and outlet valving, sectionalizing block and yoke valves with manual and remote operations capability;
* blowdown capabilities;
* check valving;
* internal inspection equipment launching facilities;
* measurement and gas analysis equipment, and associated facilities;
* a measurement building to house the custody transfer meter runs and gas sampling equipment (building size to be determined);
* a small building approximately 3.0 m x 3.4 m to house electronic equipment; and
* power and telecommunications supply (e.g., satellite communications dish).

The combined valve site and launcher/receiver site would be a fenced and graveled area, approximately 30 m x 100 m, which would be locked for safety and security. The site would include:

* sectional valves with manual and remote control capability;
* blowdown capabilities;
* launching and receiving facilities for internal inspection equipment;
* a small building approximately 2.4 m x 3.0 m to house electronic equipment; and
* power and telecommunications supply, where available (e.g., satellite communications dish).

2.3 Primary Project Activities

Table 2.3.1 below summarizes the Project activities for the construction phase (including clearing) of the Brunswick Pipeline Project. EBPC stated that clearing was anticipated to commence in the winter of 2007 with the remaining construction beginning in the summer of 2008. EBPC's expected in-service date is late in 2008.

Table 2.3.1 Summary of Project Construction Activities

Project Phase: Construction

Activity Category	Physical Work and/or Activity
Site Preparation	Project-related activities may include:

* clearing;
* grubbing;
* grading;
* duff/topsoil stripping; and
* blasting.

Pipe Installation	Project-related activities may include:

* trenching (excavation);
* boring (road and railroad crossings);
* horizontal directional drills (HDD);
* blasting;
* stringing;
* bending;
* construction of valve sites;
* welding;
* non-destructive examination of welds (e.g., x-ray, gamma ray, ultrasonic, magnetic particle);
* pipeline installation;
* installation of cathodic protection systems;
* backfilling and duff/topsoil replacement;
* hydrostatic testing and dewatering;
* pipeline commissioning;
* installation of signage and fencing; and
* site restoration.

Watercourse Crossings	Watercourse crossing alternatives include wet crossing, dry crossing, or HDD. Project-related activities may include:

* site preparation;
* instream trenching (excavation);
* temporary watercourse diversion;
* HDD;
* installation of temporary watercourse crossing structures; and
* site restoration.

Temporary Ancillary Structures and Fa-	Temporary ancillary structures and facilities may include: * temporary site access roads;

cilities

* petroleum storage areas;
* marshalling yards; and
* storage areas

Project-related activities include restoration of these sites.

Table 2.3.2 summarizes the Project activities for the operations and maintenance phase of the Brunswick Pipeline Project. EBPC anticipates the life of the facilities to be a minimum of 25 years.

Table: 2.3.2 Summary of Project Operations and Maintenance Activities

Project Phase: Operations and Maintenance

Activity Category	Physical Work and/or Activity
Project Presence	Includes all project-related aspects that would be present for the life of the Project, including: * presence of the pipeline; * presence of the RoW (including signage); * presence of valve sites, launcher/receiver sites, and meter and regulating stations; and * cathodic protection infrastructure.
Pipeline Maintenance	Includes all project-related activities that are required to maintain the pipeline, including: * monitoring of pipeline (including internal inspection); and * maintenance of valve sites, and meter and regulating stations.
RoW Maintenance	Includes all project-related activities that are required to maintain the RoW, including:

* maintenance of vegetation; and
* installation of post-construction pipeline crossings.

Table 2.3.3 summarizes the Project activities for the decommissioning and abandonment phase of the Project.

Table 2.3.3 Summary of Project Decommissioning and Abandonment Activities

Project Phase: Decommissioning and Abandonment

Decommissioning	EBPC anticipated that the pipeline would be left in the ground, disconnected from any operating facilities, filled with an inert medium and sealed.
	Cathodic protection and land use monitoring would continue.
Abandonment	EBPC stated that, at the time of abandonment, applicable standards of the day would be followed.
	Any environmental effects associated with the abandonment phase are likely to be similar to those caused by the construction phase. Pursuant to the NEB Act, an application would be required to abandon the facility, at which time the environmental effects would be assessed by the NEB and other relevant agencies.

3.0 ENVIRONMENTAL ASSESSMENT PROCESS

3.1 How the NEB Considers Certain Factors under the CEA Act

During the hearing and in final argument, a number of parties discussed certain factors contained within section 16 of the CEA Act, which sets out the factors which an RA must consider under various types of EA, such as the one conducted for this Project. The factors most discussed in this hearing included those contained in paragraph 16(1)(e) "the need for the project and alternatives to the project"; paragraph 16(2)(a) "the purpose of the project"; and paragraph 16(2)(b) "alternative means that are technically and economically feasible and the environmental effects of any such alternative means."

"Cumulative environmental effects", contained under paragraph 16(1)(a) of the CEA Act, was another area of considerable discussion. The Board issued a number of rulings and directions with respect to its consideration of "cumulative environmental effects"; the key ones are attached as Appendices 8 and 9 of this Report. The Board's consideration of cumulative environmental effects of this Project is contained in section 7.3 of this Report.

In October 1998, the CEA Agency published an Operational Policy Statement (OPS) entitled *Addressing "Need for", "Purpose of", "Alternatives to" and "Alternative means" under the Canadian Environmental Assessment Act.*[35] The purpose of the OPS is to provide clarification and guidance to RAs on how these factors should be considered in EAs conducted under the CEA Act. While not binding, the OPS provides some guidance to the Board in determining how certain factors may be addressed.

The Board notes that there is some overlap between certain of these factors and the issues the Board typically considers pursuant to its mandate under the NEB Act; for example, the need for the project and the purpose of the project are often considered in Reasons for Decision on facilities applications. However, the level of detail required in considering these factors may vary both with the mandate under which the Board is considering them and the circumstances of the application before the Board. Where there are issues that may be relevant to both mandates, the Board will address those issues in this EA, in the context of the CEA Act, and in its subsequent Reasons for Decision, in the context of the NEB Act.

3.2 "Purpose of", "Need for" and "Alternatives to" the Project

3.2.1 Background

The OPS provides the following definitions for "need for" and "purpose of":

> "Need for" the project is defined as the problem or opportunity the project is intending to solve or satisfy. That is, "need for" establishes the fundamental rationale for the project.
>
> "Purpose of" the project is defined as what is to be achieved by carrying out the project.

The OPS suggests that "need for" and "purpose of" should be established from the perspective of the project proponent, and provide the context for the consideration of alternatives to the project. For private sector projects, proponents should provide a clear statement of the need for the project. Such a statement will establish the scope of the alternatives to be subsequently considered, that is, those within the control or interest of the proponent.[36]

The OPS defines "alternatives to" the project as functionally different ways to meet the project need and achieve the project purpose. The OPS recommends the following approach for addressing "alternatives to":

> * "alternatives to" should be established in relation to the project need and purpose and from the perspective of the proponent; and
> * analysis of "alternatives to" should serve to validate that the preferred alternative is a reasonable approach to meeting need and purpose and is consistent with the aims of the CEA Act.

In addition, the OPS states that the RA should:

* identify the alternatives to the project;

* develop criteria to identify the major environmental, economic and technical costs and benefits; and
* identify the preferred alternative to the project based on the relative consideration of the environmental, economic and technical benefits and costs.

This EA Report reflects this analysis in sections 3.2.2 through 3.2.4 below. Consideration of alternative means, including alternative pipeline corridors such as a marine crossing, is addressed in section 3.3.

Finally, the OPS indicates that analysis of "alternatives to" the project should describe the process the proponent used to determine that the project is viable (technically, economically and/or environmentally), and that the level of assessment should reflect the more conceptual nature of the "alternatives to" at this stage of the process.

3.2.2 EBPC's evidence on Purpose of, Need for and Alternatives to the Project

According to EBPC, the primary purpose of and need for the Project is to provide the necessary new infrastructure to transport natural gas from the Canaport[TM] LNG Terminal, currently being constructed near Saint John, to markets in Maritimes Canada and the Northeastern US. EBPC submitted that the gas would be owned, supplied and shipped on the Brunswick Pipeline by Repsol Energy Canada Ltd. (Repsol), which is an indirect subsidiary of Repsol YPF, S.A, from whose supply portfolio the LNG would be sourced.

EBPC indicated in its environmental and socio-economic assessment (ESEA) that Repsol YPF, S.A. is one of the ten major private oil companies in the world with its oil and gas reserves located mostly in Latin America and North Africa. The proposed pipeline would enable the Repsol group of companies to market new gas supplies from the Canaport[TM] LNG Terminal, commencing as early as November 2008. Specifically, the Project was designed to enable Repsol to transport up to 750,000 million British thermal units per day (MMBtu/d) of natural gas to various markets.

EBPC submitted that M&NP, as the predecessor proponent of the Project, considered a number of alternatives to the Brunswick Pipeline, and that none of the alternatives were found to satisfy the objectives of the Project in an environmentally-responsible and cost-efficient manner. EBPC concluded that here are no economically and technically feasible alternatives to using a pipeline to reliably transport large quantities of natural gas over the distance involved in the Project. While it is possible to transport LNG supply by ship, truck or train, such options did not compare to the cross-border pipeline option in terms of economic feasibility and environmental appropriateness.

EBPC further stated that the existing SJL would not be a technically or economically viable option for meeting the Project's objectives due to the anticipated volumes of natural gas to be shipped, the insufficient size and pressure of the existing SJL, and the impact of an outage on M&NP's customers related to replacing the existing SJL with a larger pipeline.

EBPC indicated that its customer, Repsol, has consistently sought service on a stand-alone, separately-tolled, NEB-regulated international pipeline, connecting the Canaport[TM] LNG Terminal to the M&NP US system at the Canada-US border. It argued that in addition to the reasons outlined above, Repsol would not be willing to pursue any other transportation proposal.

EBPC also argued that the suggested alternatives to the Project submitted by other parties would not meet the purpose of or need for the Project, which was for a stand-alone pipeline to transport 750,000 MMbtu/d of gas from the Canaport[TM] LNG Terminal at Mispec Point to the US border to interconnect with the M&NP US system.

3.2.3 Views of the Parties

Bear Head LNG Corporation, Anadarko Canada LNG Marketing, Corp. and Anadarko LNG Marketing, LLC (collectively "Anadarko") argued that the NEB must consider and provide its own views on the issues of both need and alternatives to the Project. Further, when the evaluation of alternatives is entirely based on the tolls of the proposed Project relative to tolls on an existing pipeline system, and when these tolls are the responsibility of the NEB (i.e., tolls are not set in the market place), the Board can not defer to Repsol's and EBPC's assessment of need and the desirability of alternatives.

Anadarko also argued that no one disputed that the expansion of the existing M&NP System was capable of connecting the Canaport[TM] LNG Terminal to markets in Maritimes Canada and the Northeastern US. As far as markets in Maritimes Canada are concerned, the M&NP alternative would have provided a superior direct connection relative to the Brunswick Pipeline Project. According to Anadarko, there is, however, no evidence on the record to suggest or in any way prove that expansion of the M&NP System would not have been safe and economically feasible for Repsol or anyone else or from which the Board could conclude that the use of the existing M&NP System is not safe or economically feasible.

Anadarko submitted evidence by Mr. Peter Milne supporting the expansion of the existing M&NP system in Canada to meet the purpose and need for the Project. Anadarko indicated that this evidence would allow the Board to "compare the relative environment, economic and technical benefits and costs" of the Brunswick Pipeline Project relative to the use of the existing M&NP System, and shows that expansion of the M&NP System is vastly superior from a public interest perspective.

The Friends of Rockwood Park (FORP) argued that the depth to which EBPC considered the possible use of the existing SJL corridor and infrastructure was inadequate, and that EBPC clearly had not considered hooking into the existing M&NP main line from Nova Scotia to the US border.

Dr. Leland Thomas and Ms. Janice Eldridge-Thomas (the Eldridge-Thomases) suggested one alternative to the Project could have been the construction of a line along existing RoW, to join up with the existing 30 inch M&NP infrastructure at an appropriate location near Sussex, NB, with the addition of compressors if required. Another alternative to the Project is to site a regassification facility (plant or ship) near the anchor market.

Views of the Board

In the Board's view, generally, "alternatives to" a project, in the context in which it arises in the CEA Act, may incorporate any feasible different methods for the transportation of gas; not undertaking the project at all; and any feasible different project that would achieve the objectives of the proposed project, including possible pipeline expansions or looping by other proponents.[37] Proposed alternatives that do not meet both the purpose of and need for the project, as defined by the proponent, may not be considered by the Board to constitute "alternatives to" the project under the CEA Act.[38] For projects under review which do not pose significant adverse environmental impacts, the Board may not be required to go further to make specific findings of fact or to conduct a comparative EA with respect to the alternatives to the projects under review.[39]

It is worth noting that, unlike the requirement to consider the environmental effects of alternative means, there is no legislated requirement to consider the *environmental effects* of alternatives to the project. Nor is there a legislated requirement as to the amount or adequacy of evidence to be adduced with respect to alternatives to the project. In the Board's view, the requirement to consider alternatives to a project, when included as part of the scope of factors to be considered when conducting an EA, as is the case here, does not elevate alternatives to the same position as the project under review, or necessarily require the same quantity or detail of evidence as is required for the project under review. The focus of the mandate always remains upon the project described in the formal description contained within the scoping documents. The sufficiency of the evidence with respect to the alternatives to the project considered by the Board is a matter that falls within the judgement of the Board, and may vary with respect to the application before it.

As noted during the oral portion of this hearing,[40] consideration of alternatives to the Brunswick Project raised in the context of the CEA Act should not be used to delve into a detailed economic analysis of the benefits and burdens of that alternative. For example, consideration of alternatives to the Brunswick Pipeline Project under the CEA Act does not require an analysis of what the tolls might be on a potential alternative to the Project in comparison to the tolls on the Brunswick Pipeline[41] nor an analysis of the "long-term effects of avoiding the toll on the Maritimes and Northeast Pipelines system."[42] That level of detailed analysis would greatly expand the scope of the CEA Act EA analysis without adding sufficient probative value to the decision the Board has to make on the environmental effects of the Brunswick Project, and is not required for this EA Report.

In applying the relevant case law[43] and the OPS, the Board finds that both the need for this Project and the purpose of this Project are to be considered in order to provide a basis for the consideration of alternatives to the Project in this EA Report. The Board also notes that gathering information on the need for the Project may also be of assistance if a decision must ultimately be made under the CEA Act whether, despite significant environmental effects, the Project is otherwise justified.

Furthermore, the quantity and detail of the evidence required to allow the Board, as an RA, to carry out its consideration of these factors, and the degree of scrutiny to undertake this task, will vary with the seriousness of the environmental effects of the proposed project. It is within the Board's discretion to determine the adequacy of the evidence provided for both these factors based on the circumstances of the application being considered.

In this hearing, the proponent is EBPC. Accordingly, the need for and the purpose of the Project, for the purpose of the CEA Act EA, are to be established from the perspective of EBPC.

The Board accepts that the need for and the purpose of the Project, from the perspective of EBPC, has been sufficiently defined by EBPC, that is, to provide the necessary new infrastructure to transport natural gas from the Canaport[TM] LNG Terminal to markets in Maritimes Canada and the Northeastern US. The evidence further indicates that EBPC's customer, Repsol, is seeking a stand-alone pipeline from the Canaport[TM] LNG Terminal to the interconnect with the M&NP US system. The Board does not find it appropriate in conducting its EA of the Project under the CEA Act, and on the basis of the record and the facts of this case, to redefine the purpose of or need for the Project from that set out by EBPC. The purpose of and need for the Project are not so narrowly defined as to preclude the reasonable assessment of alternatives to the Project, nor is the rationale or the goal to be achieved by the Project unclear.

As previously mentioned, under the Board's mandate under the NEB Act, the purpose of and need for the Project will receive further consideration in determining whether the Project is in the present and future public convenience and necessity.

Accordingly, the alternatives to the Project to be considered in this EA prepared in accordance with the CEA Act are to be informed by the purpose of and need for the Project.

During the oral portion of the hearing, the Board provided a ruling related to alternatives to the Project. This ruling is attached as Appendix 5 (Questioning about Alternatives to the Project). All rulings are available on the Board's website. Given the context for its consideration of this and other factors under the CEA Act, contained above, the Board concludes that it has sufficient information about the alternatives to the Project and EBPC's analysis of those alternatives for the purpose of this EA under the CEA Act.

The Board finds that the alternatives of transporting gas by ship, truck, or train are not as reliable, environmentally-safe or secure as transporting gas through an underground pipeline. It was clear on the evidence before the Board that the existing SJL could not currently transport the amount of gas required to be transmitted by this Project. It is notable as well that the owner of the SJL, M&NP Canada, while participating in this proceeding, did not take the position that using the SJL would be feasible, and, in fact, argued the opposite position in its 6 September 2006 correspondence to the Board, based on the evidence provided by EBPC.

In the Board's view, the alternatives to the Project raised by Anadarko, FORP and the Eldridge-Thomases are not appropriately considered to be "alternatives to" the Project under the CEA Act, because they do not serve the same purpose of and need for the Project, as set out by EBPC. For example, an expansion of the M&NP Canada System would not result in a separately-tolled, stand-alone pipeline from the Canaport[TM] LNG Terminal to the interconnect to the M&NP US System at the Canada-US border. Even if they could be considered "alternatives to" the Project, these options have been rejected for commercial and business reasons by the Proponent and its shipper, and this rationale for rejection under the CEA Act is supported in the jurisprudence.[44]

The Board finds that the alternatives to the Project considered by EBPC that would meet the purpose of and need for the Project from the Proponent's perspective, were reasonably concluded by EBPC to not be technically and economically feasible, and therefore are not viable alternatives to the Project. Furthermore, the information provided during the hearing supports the selection of the Project. Finally, taking into consideration its ultimate conclusion that the Project is not likely to cause significant adverse environmental effects, the Board need not undertake a more detailed assessment of the alternatives to the Project under the CEA Act.

Notwithstanding the Board's finding that the "alternatives to" the Project discussed above are either inappropriate "alternatives to" the Project under the CEA Act, or were reasonably rejected by EBPC, the Board notes that further consideration of the proposals by Anadarko, FORP, and the Eldridge-Thomases may be included as part of the Board's deliberations on whether the Project is in the present and future public convenience and necessity in the Board's reasons for decision under the NEB Act.

3.3 Alternative Means

3.3.1 Background

Pursuant to paragraph 16(1)(d) of the CEA Act, an RA must consider alternative means of carrying out the project.

The OPS defines "alternative means" as the various ways that are technically and economically feasible that the project can be implemented or carried out. This could include for example, alternative locations, routes and methods of development, implementation and mitigation.

The "alternative means" may include different routes for the project to follow between the terminal points selected, or different ways of carrying out the work required to undertake the project that are both "technically and economically feasible." The RA must also consider the environmental effects of the alternative means; however, there are no legislated requirements regarding the quantity or level of detail of information that a proponent must provide and the RA must consider in order to satisfy this factor.

3.3.2 Views of EBPC

Consideration of Alternate Corridors

EBPC noted that, in general, the corridor alternatives identified for evaluation represented the routes from the pipeline origin to its terminal point, avoiding known concentrations of environmental constraints, and following existing RoWs wherever practicable. The preferred corridor includes both an urban and rural component.

Four main urban corridor alternatives were identified and evaluated to determine the preferred corridor from the east side of Saint John, where the Canaport[TM] LNG Terminal is located, to the west side of Saint John. One of the urban corridor alternatives considered consisted of a marine crossing of the Saint John Harbour. Four corridor sub-alternatives through the City were identified in an attempt to avoid built-up areas and allow the crossing of the Saint John River without undue difficulty.

Three main rural corridor alternatives were identified from the west side of Saint John to the international border near St. Stephen, New Brunswick.

See Figure 2 for the various alternative corridors considered, and Figure 3 more specifically for the urban alternative corridors.

Selection Process

According to EBPC, a multi-disciplined project team, assisted by various consultants, was initially assembled to evaluate corridor alternatives and select a preferred corridor for the Project. Collective experiences of the team included: recent knowledge of NEB-regulated corridor selection processes, including the processes applied in relation to the M&NP Mainline and SJL; environmental permitting; RoW land acquisition; and extensive east coast urban, rural and offshore pipeline construction experience.

Selection Criteria

EBPC submitted that the preferred corridor was selected on the basis of:

* safety;
* constructability;
* minimizing project cost;
* impacts to project schedule; and

* environmental constraints and minimizing disturbance through the use of existing corridors where practicable.

EBPC indicated that it had a team of experts evaluate and compare the corridors, and determine what was the preferred one, taking into account all of those criteria. The corridor selection process involved a balancing of all of the criteria in determining the preferred corridor.

The technical studies used by EBPC to support the evaluation of alternative corridors included:

* a preliminary evaluation of interferences presented by underground infrastructure and related constructability issues (Godfrey 2005);
* a technical feasibility study of potential marine crossing alternatives (PCS 2005); and
* a technical feasibility study of HDDs across major watercourses and water bodies (AK Energy 2005).

In support of its application, EBPC also submitted a quantitative risk analysis of the Project based on EBPC's preferred route (Bercha International Inc., 2005).

Consultation/Rockwood Park Variants

EBPC stated that it or its predecessor, M&NP, held discussions with various stakeholder groups and regulatory agencies to help identify potential corridor alternatives and to obtain feedback on the evaluation criteria for selecting a preferred corridor. Several challenges with the preliminary preferred corridor were identified during the public and stakeholder consultations. Specifically, some members of the public were opposed to a pipeline corridor along an existing power transmission line RoW in Rockwood Park. In response to these concerns, the variants to the preliminary preferred corridor were identified to avoid the Park. The two variants, one north and one south of Rockwood Park, were assessed in the environmental assessment for the Project. Refer to Figure 4 for an illustration of the two variants around Rockwood Park.

EBPC indicated that the proposed corridor through Rockwood Park is preferred because it follows an existing utility corridor through the Park, avoids impacts to residences, does not alter the existing land use and is the shortest option that would result in the least temporary construction impact compared to the two variants. However, EBPC submitted that each of the two variants around Rockwood Park is acceptable based on a preliminary review.

Preferred Corridor Selected

EBPC submitted that only one corridor and its accompanying variants through Saint John were found to be technically and economically feasible. This route, the Pleasant Point sub-alternative and its variants, is EBPC's preferred corridor in the urban portion of the route. The Pleasant Point sub-alternative passes through the City of Saint John and parallels a transmission line through Rockwood Park. Refer to Figure 1 for an illustration of the preferred corridor.

A route known as the International Power Line (IPL) alternative was selected as the best alternative for the rural portion of the route for environmental, technical and economic reasons. The IPL alternative follows the SJL RoW until the planned New Brunswick Power (NB Power) IPL RoW is intersected, then parallels the IPL (to the extent practicable), leaving the IPL RoW just before the St. Croix River, and crossing this river immediately adjacent to the existing M&NP Mainline. The other two rural alternatives were more costly and presented additional technical challenges, such as a potentially high risk HDD watercourse crossing. The additional environmental effects of these two alternatives and a combination of technical risk and/or increased cost resulted in their rejection.

Together, the Pleasant Point sub-alternative (and its variants) and the IPL alternative, including the portion which parallels the SJL, make up EBPC's preferred corridor for the Project.

EBPC noted that the rural section of its preferred corridor generally passes through undeveloped forested lands and, for the most part, abuts existing or proposed pipelines, roadways or power lines. Of the entire 145 km length of the preferred corridor, approximately 95 km follows, and includes within its boundaries, existing or planned RoWs, including power lines, highways and roads.

EBPC indicated that discussions with NB Power and engineering studies are underway to determine if the pipeline can be safely located approximately 13 m from the closest power line conductor. Among other things, consideration is being given to the height of construction equipment and spoil piles, ground clearance below the conductors under different operating and climatic conditions, the effects of inducted voltage on the pipeline, the effects of blasting on the tower structures, and operational requirements of NB Power. The final proposed location of the pipeline would also be based on environmental and topographical considerations. EBPC would strive to maximize the amount of easement overlap.

The delineation of the 30 m-wide pipeline RoW within the preferred corridor would be completed following regulatory approval by the NEB, if approval is granted. This delineation would be based on further site-specific constraint mapping, field investigations, and information received from the public, landowners, other interested parties, and government agencies. Urban corridors defined by EBPC for this Project were typically 100 m in width, except in specific areas where they were widened to permit the future consideration of detailed routing options. Segments of the preferred corridor in rural areas that followed the existing SJL were 200 m wide and segments of the preferred corridor in rural areas that followed the existing IPL were 500 m wide.

Marine Crossing

EBPC submitted that a marine crossing of Saint John Harbour was considered thoroughly but rejected as it would not be practical due to the higher safety, technical, cost, schedule, and environmental risks as compared to the preferred corridor. The key difficulties identified with a corridor that includes a marine crossing of the harbour compared to an on-land route included:

* greater safety risks associated with a marine crossing, including occupational safety risks for divers and other marine construction workers on barges and on other vessels;
* greater construction risks associated with a marine crossing, such as the technical challenge of the bottom-lay portion of the marine crossing and HDD installations at the entry and exit to the water due to the tidal changes;
* the environmental risk and potential impacts of a marine crossing to marine fish habitat and shoreline habitat, including the Saints Rest Marsh area, particularly if HDD installations were not successful;
* the cost estimate for a pipeline constructed in a corridor that included the marine crossing used in EBPC's application was 85% greater than the capital cost for the preferred corridor; and
* very high risk of delays to the Project for completing a marine crossing in winter months. EBPC submitted that pipeline operation risks and commercial risks were additional issues related to a marine crossing.

Other Alternative Means

In addition to considering various corridors, the Proponent considered the use of nominal pipe size (NPS) 24 inch, NPS 30 inch and NPS 36 inch outside diameter pipe. EBPC submitted that the NPS 24 and NPS 36 options were eliminated after considering the necessary contract flow rate and maximum operating pressure as well as the associated costs.

3.3.3 Views of the Parties

FORP submitted an analysis prepared by Accufacts Inc. on the application as it pertained to two major route options affecting the City of Saint John, NB. The analysis suggested that the application was seriously incomplete in at least two areas:

1. the declaration dismissing the marine route option that would essentially bypass the City of Saint John as "not feasible" was not adequately supported, raising significant questions as to the claimed difficulty, cost, or scheduling impact of this option; and
2. the Bercha quantitative risk assessment was missing critical information to support or justify the risk transects determined for the on-land route through the City of Saint John.

FORP submitted that the application appears to be misrepresenting or over-estimating the difficulties, costs, or risks associated with the harbour crossing, while understating the risks associated with an on-land route through the City. In addition, the Saint John Harbour marine crossing options did not appear to have been thoroughly or properly evaluated or documented as a *bona fide* pipeline route. FORP argued that additional information was warranted to permit an informed and proper decision concerning a prudent Brunswick Pipeline route selection.

FORP opposed EBPC's plan to construct the Project through Rockwood Park and the City of Saint John, and instead advocated a marine route across the outer harbour of Saint

John, a safe route away from the City and its population. FORP submitted an affidavit indicating that FORP collected signed petitions with approximately 15,269 signatures requesting that the NEB only permit an undersea route for any approved natural gas pipeline.

FORP and other Intervenors argued that EBPC failed to properly evaluate the alternative means to carry out the Project and failed to carry out its obligations under Section 16 of the CEA Act.

Mr. Horst Sauerteig submitted that a submarine pipeline circumventing the City is safer for its residents and for the environment, and could be constructed safely by an experienced marine contractor at a cost comparable with EBPC's estimate of a pipeline through the City of Saint John. Mr. Sauerteig proposed a marine pipeline route alternative to the marine crossing considered by EBPC. He disputed the estimated cost of the marine crossing put forward by EBPC, and estimated a much lower cost for EBPC's marine crossing than did EBPC. Mr. Sauerteig submitted that EBPC's preferred corridor through the City of Saint John is not in the best interest of its citizens, and that many of the burdens of EBPC's preferred corridor to the citizens can be eliminated by adopting his proposed marine pipeline alternative. Mr. Sauerteig argued that EBPC failed to investigate in a professional manner all "alternative means of carrying out the project."

EC submitted that planning for the Project should consider the potential for Project activities to result in the disposal of materials into the marine environment and the associated need for a Disposal at Sea (DAS) permit under CEPA 1999. The three scenarios described in EBPC's ESEA that may include activities subject to the DAS provisions of CEPA 1999 include a pipeline crossing of Saint John Harbour, open cuts of the Saint John River, and disposal of sulphide-bearing materials at sea. EC recommended that activities that may be pursued on a contingency basis and could require a DAS permit be described and assessed in sufficient detail to support a potential DAS permit application.

Many of the letters of comment received and oral statements made, as well as the evidence submitted by several Intervenors expressed concern over and opposition to a pipeline route through the City of Saint John, and many suggested a strong preference for a marine crossing.

3.3.4 EBPC Response to Intervenors

In response to evidence from Intervenors disputing estimated costs for the marine crossing, EBPC submitted that its revised estimated costs for the marine crossing had increased since its initial estimation. The revised estimated cost for the marine portion reflected order of magnitude increases based on recent quotes received for similar marine projects.

EBPC indicated that the success of the Canaport[TM] LNG Terminal is very dependent upon the commercial arrangements between Repsol Canada and EBPC, and achieving a timely in-service date in accordance with the current land route construction schedule for completion of the Brunswick Pipeline. A conclusion was reached early on that, considering the likely costs and scheduling delays, a marine crossing would not be feasible. As a result, the detailed engineering and environmental studies with respect to a marine crossing were not undertaken.

EBPC submitted that it did look at the alternative marine route proposed by Mr. Sauerteig. EBPC indicated that the information Mr. Sauerteig provided would not result in a materially different result to EBPC's analysis of a marine route in general. EBPC still preferred its preferred corridor for the Project when compared to Mr. Sauerteig's alternative.

EBPC submitted that the construction and operation of the on-shore pipeline in the preferred corridor described in the application is environmentally-acceptable, economical, safe and efficient as experience across North America has demonstrated over the years. Both EBPC and Repsol have concluded that a marine crossing is not feasible. EBPC indicated that the Brunswick Pipeline will not be built across Saint John Harbour.

In response to claims that EBPC has not adequately considered the alternative means of a marine crossing, EBPC argued that the Board has been provided with an abundance of evidence regarding the feasibility of a marine crossing. EBPC:

* has provided feasibility studies that considered two marine corridors;
* answered extensive interrogatories with respect to the marine alternatives and its feasibility analysis;
* evaluated the Intervenors' evidence on the marine alternatives and made related information requests;
* responded to the Intervenor evidence with respect to the marine crossings with further reply evidence; and,
* made its marine experts available for cross-examination for approximately seven days.

In its response to EC's concerns about the potential for a DAS permit, EBPC indicated that at the time the ESEA was submitted, no disposal at sea of sulphide-bearing rock was being considered for the Project. EBPC also noted that during the construction of the SJL, most sulphide-bearing rock encountered was relatively low in reactivity and a combination of blending into the RoW grade materials and/or adding limestone was sufficient mitigation.

EBPC proposed an HDD to cross the Saint John River as part of the Project, and its ESEA was based on that crossing method. EBPC indicated that it would prepare a contingency plan in the event that the HDD was not feasible.

EBPC further indicated that should it become apparent that a DAS permit may be required for the Project, the appropriate studies and plans would be discussed with EC and undertaken for this activity.

Views of the Board

During the hearing, a number of parties raised concerns with respect to the preferred corridor, and suggested that alternative means, including alternative corridors, were not sufficiently examined by EBPC. The Board provided a ruling related to alternative means to provide some guidance to parties. This ruling is attached as Appendix 6. Additional guidance related to the Board's consideration of alternative means is contained below.

In relation to the Board's consideration of "alternative means", there is no obligation to select the alternative with the least environmental impact. The approach of the CEA Act is to require a finding that the alternative *chosen* not be likely to cause significant adverse environmental effects.[45]

In the Board's view, "alternative means" of carrying out the Project are methods which are technically and economically feasible and include those means that are within the scope and control of EBPC.[46] The consideration of "alternative means" does not involve a consideration of alternative means that would involve different end points for the pipeline, nor does it necessarily require that all possible reasonable alternative means must be examined. Furthermore, in the absence of a legislated requirement as to the quantity or detail of the evidence that must be considered, the extent to which the Applicant has provided information on alternative means, the adequacy of information provided for the Board's consideration and the Board's determination as to whether consideration of this factor under the CEA Act has been fulfilled is a question of judgment.[47]

The Board finds that EBPC provided sufficient evidence regarding its consideration of a marine crossing of the Saint John Harbour, and that this evidence underwent broad questioning by parties to the hearing. EBPC's evidence was supported by credible expert witnesses and EBPC's conclusions with respect to the feasibility of a marine crossing were reasonable, based on the evidence adduced.

Although EBPC was not required to consider or provide information on *all* possible alternative means, the Board finds that, in any event, EBPC sufficiently examined and provided an adequate level of information in response to those alternative means proposed by Intervenors, such as Mr. Sauerteig's proposed alternative marine route, to supplement the information provided on the record by other parties and to allow for sufficient consideration of these alternative means, their technical and economical feasibility, and their environmental effects.

Evidence was also provided with respect to the other on-land corridors considered by EBPC in this proceeding, as described in section 3.3.2 above. These on-land alternative means were also extensively explored by parties in the proceeding. EBPC's conclusion with respect to the selection of an on-land corridor were reasonable, based on the evidence adduced.

Further, EBPC provided evidence that it considered various sizes of pipe and the feasibility of using HDD at several watercourses. The Board notes that this evidence was only briefly questioned, if at all, or argued upon by parties.

The Board concludes that EBPC has provided adequate information on alternative corridors and construction methods that are technically and economically feasible for the Board to consider these alternative means and their environmental effects. In the Board's view, the rationale provided by EBPC for rejecting the alternative means it considered, as well as the Intervenors' proposed alternative means, is reasonably founded in the evidence, and supports, among other things, the selection of the preferred corridor, construction methods and size of pipe.

Further consideration of the evidence may be required by the Board in order to fulfill its mandate under the NEB Act, and will form part of the content of separate Reasons for Decision.

The Board notes EC's recommendation that activities that may be pursued on a contingency basis and that could require a DAS permit be described and assessed in sufficient detail to support a potential DAS permit application. However, EBPC has indicated that it will not pursue a pipeline crossing of the Saint John Harbour. An open cut of the Saint John River was not considered as part of the environmental assessment for the Project. EBPC has indicated that an open cut of the Saint John River would only be pursued as a contingency, and that it would prepare an environmental assessment of the open cut.

If the Project were to receive regulatory approval, the Board would recommend a condition be imposed to require that EBPC construct the crossing(s) of the Saint John River using the HDD method or, if this is not feasible, apply to the Board for approval of an alternative crossing technique, and include an EA of the proposed alternative with its application. Therefore, the Board has included a recommendation to this effect in section 9.2 as recommendation I.

The Board expects that EBPC would include sufficient detail to support a potential DAS permit application as part of the environmental assessment of the proposed alternative crossing of the Saint John River.

The remainder of this Report focuses on the Project as proposed by EBPC and described in section 2.0 (Project Description).

4.0 DESCRIPTION OF THE ENVIRONMENT

The following descriptions of the environmental and socio-economic settings are based on the evidence submitted by EBPC and focus on the preferred corridor as proposed by EBPC. Any comments provided by interested parties with respect to the environmental and socio-economic elements below are addressed in sections 5.5 and 7.0, and Appendix 1 of this Report.

4.1 Environmental Setting

Physical Environment

* Topography varies from gently undulating/level to hummocky/rolling with more than 90% of the urban and rural corridor having a slope of less than 10%.
* Approximately 64% (22.8 km) of the urban section and approximately 67% (74.5 km) of the rural portion of the preferred corridor crosses through potential sulphide-bearing or acid-generating rock that contain various sulphide minerals.
* Five earthquakes with a magnitude greater than 2.6 on the Richter scale have occurred in the Bay of Fundy in the last 30 years.
* The Bay of Fundy moderates the local air temperature and stabilizes the flow of large air masses. This stability can greatly influence the dispersion of exhaust plumes from sources located on the coast of the Bay of Fundy.

Water Resources

* Two Watershed Protection Areas have been identified within the preferred corridor: Dennis Stream Watershed near St. Stephen and the Spruce Lake Watershed, west of Saint John.
* The boundary of a third Watershed Protection Area, the East and West Musquash Watershed, is within 50 m of the preferred corridor.
* The preferred corridor intersects valleys and hillsides in several locations where springs may occur.
* Records for 19 wells within 500 m of the preferred corridor were available from a provincial database.
* Aerial photography suggests that there may be more than 105 domestic wells within 500 m of the preferred corridor that have not been included in the provincial database.
* A total of 123 watercourses or water bodies are within or adjacent to the preferred corridor.

Fish and Fish Habitat

* Three species of fish considered either Species at Risk pursuant to the *Species at Risk Act* (SARA) or Species of Conservation Concern occur within the assessment area.[48] These include anadromous Atlantic Salmon, listed as "May be at Risk" by New Brunswick Department of Natural Resources (NBDNR), striped bass (*Morone saxatilis*), listed as "May be at Risk" by NBDNR and also "Threatened" by the Committee on the Status of Endangered Wildlife in

Canada (COSEWIC), and shortnose sturgeon (*Acipenser brevirostrum*), listed as a "Species of Special Concern" under SARA.

* In NB, the Inner Bay of Fundy Atlantic salmon (*Salmo salar*) is listed as "Endangered" under SARA and the Lake Utopia dwarf smelt (*Osmerus sp.*) is listed as "Threatened" under SARA. Neither of these species is known to exist within watercourses crossed by the preferred corridor.
* Recreational fish species in the preferred corridor, as determined by DFO, include various salmonids, smallmouth bass and American eel and gaspereau (alewife); striped bass are also commonly fished in the Saint John River.
* Brook trout were determined to be the dominant recreational fish species in the preferred corridor.

Vegetation

* The southern-most areas of the preferred corridor may support tolerant hardwoods such as sugar maple and yellow birch, but are dominated by red maple, white birch, balsam fir and white spruce.
* Where the preferred corridor parallels the NB Power IPL RoW, tolerant hardwoods such as sugar maple and hemlock are able to persist; butternut (a federal Species at Risk) are present but are mostly restricted to the Saint John River valley; the more common quaking aspen are also characteristic in regenerating areas that have been disturbed by deforestation or fire.
* Invasive vascular plants that can be expected within the study area include purple loosestrife, Eurasian watermilfoil, glossy buckthorn and reed canary grass.
* A total of 14 plants of conservation concern were encountered within approximately 50 m of the preferred corridor during field surveys.
* A total of 80 wetlands were identified during the desktop study and field surveys as occurring within the preferred corridor, with a total area estimated to be 800 hectares (ha).
* The preferred corridor intersects with, or is near, three vegetation-based environmentally significant areas and runs through the southern edge of the Loch Alva Protected Area.

Wildlife and Wildlife Habitat

* The eastern NB population of cougar is listed as "Endangered" under the NB *Endangered Species Act* (NB ESA) and the Canada lynx is listed as "Regionally Endangered" under the NB ESA. Both lynx and cougar tend to be wide-ranging and suitable habitat for both species is likely distributed throughout the Project area; however,

the preferred corridor is not known to represent important limiting habitat for either species.

* The Gaspé shrew is listed as "Special Concern" on Schedule 3 of SARA; however, based on its restricted range, it is unlikely to inhabit areas in the preferred corridor.
* Other mammal species that have been assessed to be "Sensitive" by NBDNR include the eastern pipistrelle, little brown bat and northern long-eared bat; however, the preferred habitats of these species are avoided by the preferred corridor.
* The long-tailed shrew is considered "May be at Risk" by NBDNR but are unlikely to inhabit areas of the preferred corridor based on their habitat preferences.
* Eight species of birds with the potential to be in the area of the Project are listed on Schedule 1 of SARA, including Piping Plover, Eskimo Curlew and Roseate Tern as "Endangered"; Least Bittern and Peregrine Falcon as "Threatened" and Harlequin Duck, Yellow Rail and the eastern population of Barrow's Goldeneye as "Special Concern"; however, it is not likely that any of these species inhabit the preferred corridor given their known ranges and preferred habitats.
* Bald Eagle is considered "Regionally Endangered" under NB ESA, and while there were no nests along the preferred corridor, there was one Bald Eagle recorded during the field surveys.
* Red-shouldered Hawk, Short-eared Owl and Bicknell's Thrush are listed as "Special Concern" on Schedule 3 of SARA; there is suitable habitat within the vicinity of the preferred corridor for both the Red-shouldered Hawk and Short-eared Owl, and although the preferred breeding habitat for Bicknell's Thrush is not common in this area, there was one recorded during bird surveys.
* Wood turtle is listed as "Special Concern" on Schedule 3 of SARA and were observed at Black Brook and Dennis Stream during surveys in August 2001 for the NB Power IPL.
* Dusky salamander is considered "Sensitive" by NBDNR, a database search of the area within 5 km of the preferred corridor returned three records for dusky salamander.
* Maritime ringlet butterfly is listed as "Endangered" on Schedule 1 of SARA but as they are only known to occur near the City of Bathurst, this species is not likely to occur along the preferred corridor.
* Monarch butterfly is listed as "Special Concern" on Schedule 1 of SARA, a database search of the preferred corridor and the surrounding 5 km returned two records for monarch butterfly.
* In the Project area, the most limiting mammal habitat is wintering areas for white-tailed deer and moose; the preferred corridor traverses nine deer wintering areas.

* An area designated as mature coniferous forest habitat intersects the preferred corridor; total area is approximately 690 ha, of which approximately 290 ha fall within the preferred corridor.
* Five wildlife-based environmentally significant areas have been identified in the vicinity of the preferred corridor and only the Utopia Wildlife Refuge intersects the preferred corridor.

Atmospheric Environment

* Southern NB has a relatively heavy industrial base that includes various commercial and industrial facilities, which contribute to sources of air contaminants.
* Data for conventional air contaminants for selected industrial facilities in southern NB (maintained by NBDOE) show a slightly increasing trend; however, sulphur dioxide emissions appear to be following a downward trend (data is from 1997-2003).
* Annual average values for nitrogen dioxide for all sites monitored in Saint John ranged from 10-30 ug/m[superscript 3], which were well below the ambient annual average standard of 100 ug/m[superscript 3].
* The 1-hour and 24-hour ambient sulphur dioxide standard (450 and 150 ug/m[superscript 3] respectively) were exceeded occasionally during 2003 at several monitoring stations in and around the Saint John area.
* No exceedances of the California/Greater Vancouver Regional District 24-hour standard of 50 ug/m[superscript 3] of particulate matter less than 10 microns were recorded at any of the monitoring sites in the Saint John network for 2002-2003.
* Particulate matter less than 2.5 microns monitored during the period of 2000-2003 is in compliance with the Canada-Wide Standard (30 ug/m[superscript 3] as a 24-hour average over 3 years).
* During 2002 and 2003, ground level ozone concentrations (monitored at 4 locations in the Saint John network) did not exceed the 1-hour National Ambient Air Quality Objective (160 ug/m[superscript 3] or 80ppb).
* There were a total of 5 hours during 2003 where the Canada-Wide Standard for 8-hour average ground level ozone (130 ug/m[superscript 3]) was exceeded.
* Peak hourly values of carbon monoxide, for sites monitored from 1996-2003, were below the applicable standard of 35,000 in 2003. There were no exceedances of the 8-hour standard (15 000 ug/m[superscript 3] in 2003).

Rockwood Park

* In Rockwood Park, the preferred corridor for the Project follows an existing power transmission line RoW which spans a distance of 2.4 km.
* Within the Park, the A-frame building, horse barns, and interpretive centre depend on wells for water supply.
* Potential for contaminated soils exist within the preferred corridor of Rockwood Park.
* The Project potentially crosses at least six watercourses that may be fish-bearing.
* No known fish Species at Risk exist in watercourses crossed in Rockwood Park.
* Yellow Slipper, a vascular plant Species of Conservation Concern, was found at the edge of the preferred corridor, and would not be affected by the Project.
* There are three wetlands identified in the Park.
* There are a number of caves in Rockwood Park; however, these are avoided by the preferred corridor. Caves within the Park would not be affected by activities related to the Project.
* White-tailed deer are known to make use of corridors and trails such as power line RoWs (e.g., in Rockwood Park), pipeline RoWs (e.g., SJL) and abandoned railroad tracks. Deer are relatively abundant in southern NB and are generally not limited by habitat.
* No deer wintering areas were identified in Rockwood Park.
* No wildlife Species of Conservation Concern or habitat for such species has been noted within the proposed corridor for the Park.

4.2 Socio-Economic Setting

Aboriginal Interests

* There are 15 First Nation communities in the NB.[49] These communities are made up of two separate, although closely related, Nations: the Maliseet and the Mi'kmaq.
* The Project falls within the traditional territory of the Maliseet, with the closest community, Oromocto First Nation, approximately 65 km away from the preferred corridor. All of the Mi'kmaq communities are located over 100 km from the assessment area, with the furthest being located approximately 300 km away.
* As the Project would parallel, to the extent practicable, the existing NB Power IPL and SJL RoWs, the Traditional Ecological Knowledge (TEK) information gathered for those projects was used for EBPC's ESEA in addition to information gathered through open houses held at each of the 15 Aboriginal communities.
* Concerns raised in past studies for the SJL included disturbance to: traditional hunting, fishing and gathering areas; burial and/or ceremonial sites; and unidentified archaeological sites.

* Current consultation efforts identified similar issues, including a general concern for Aboriginal sacred lands and for historical Aboriginal settlements, although no specific areas have been identified.

Land and Resource Use

* The Project would pass through one incorporated municipality, the City of Saint John. Outside of Saint John, the pipeline extends from Lorneville to the international border at the St. Croix River near St. Stephen.
* The preferred corridor is set in both an urban and rural environment and passes through or near existing/proposed residential subdivisions, Rockwood Park in the north end of Saint John, the environmentally significant areas of Musquash Harbour, Saints Rest Marsh, and the extreme southern portion of the protected Spruce Lake Watershed.

Urban Setting

* Saint John Census Metropolitan Area is NB's largest urban centre, with a population of approximately 140,000.
* Part of the Project is located within the urban setting of Saint John (approximately 35 km), including areas with substantial underground infrastructure, complex road networks, heavy industry and residences.
* Several large industries are located near the preferred corridor, including a port, an oil refinery, a pulp and paper plant, transportation infrastructure (e.g., roads and railways), and numerous small businesses and other commercial properties that support the industry base.
* The urban portion of the preferred corridor parallels existing utility RoWs, to the extent practicable, while generally avoiding most of the recreational areas and attractions located in Rockwood Park.
* Rockwood Park is a popular destination for Saint John residents and visitors. In various seasons, Rockwood Park offers the following attractions: Kiwanis Playpark at Fisher Lakes; Rockwood Park Municipal Golf Course & Aquatic Driving Range; Rockwood Park Campground; Cherry Brook Zoo & Vanished Kingdom Park; beaches at Fisher Lakes and Lily Lake; hiking, biking, cross-country skiing, and running trails; picnic sites at Fisher Lakes and throughout the wilderness zone of the Park; Rockwood Stables & Turn of the Century Trolleys; and horseback riding.
* Approximately one third of the urban portion of the preferred corridor is located within close proximity of residential homes. These areas include Champlain Heights, Lancaster, Spar Cove Road, Milford, and Millidgeville. New subdivisions are currently being devel-

oped or are planned within the urban portion of the preferred corridor.

Rural Setting

* The remainder of the Project is within the rural setting of southwestern NB (approximately 110 km); the preferred corridor travels through both forested and agricultural areas, and intersects the protected Dennis Stream Watershed, Route 1 and a number of secondary highways.
* The rural portion of the preferred corridor is located adjacent to existing RoWs, to the extent practicable, in an effort to minimize land use conflicts for the Project.
* Primarily crossing through woodland, the preferred corridor does pass through intermittent residential and industrial land use and cross various roads and utility RoWs.
* Numerous trails used by all-terrain vehicle (ATV) operators and seasonal hunters occur in the rural portion of the preferred route, although no properties are specifically set aside for recreational purposes.
* Agricultural lands occur within the preferred corridor, including two blueberry farms in addition to the more traditional farms of hay and grains.

Infrastructure and Services

* The preferred corridor interacts with numerous water mains, as well as sanitary and storm sewers within Saint John.
* The preferred corridor intersects with the CN Rail line in two different locations.
* Three hospitals and other health and long-term/chronic care facilities (e.g., the Worker's Compensation Rehabilitation Centre) are located in Saint John. The largest of these units, the Saint John Regional Hospital, is a 700-bed acute care teaching hospital, and is accessed via either University Avenue or Sandy Point Road. It is NB's largest regional hospital and one of the largest in eastern Canada.
* Within the urban region of the preferred corridor, there are 33 establishments that provide overnight accommodation, 27 of which provide year-round lodging. Within the vicinity of the rural section of the preferred corridor, there are 54 places identified that provide overnight accommodation, 31 of which provide year-round lodging.
* Archaeological and Heritage Resources
* The preferred corridor was preliminarily divided into areas of low archaeological potential and moderate to high archaeological poten-

tial. Areas of moderate to high archaeological potential may include both pre-contact and historic period resources.

* Sites of high archaeological potential were identified, including along the shoreline of the Saint John River, on the Musquash River, at St. David Ridge, on the west side of Magaguadavic River and at most of the other watercourses crossed by the preferred corridor.
* Based on the history of the area, and the level of disturbance and studies from past projects, the archaeological potential for most of the preferred corridor was considered by EBPC to be low to moderate.

5.0 PUBLIC PARTICIPATION

5.1 Public Participation under the CEA Act

Public participation is a central element of the CEA Act. The importance and function of public participation is cited in both the preamble and purpose of the CEA Act:

> ... Whereas the Government of Canada is committed to facilitating public participation in the environmental assessment of projects to be carried out by or with the approval or assistance of the Government of Canada and providing access to the information on which those environmental assessments are based; ...

and

> The purposes of this Act are ...
>
> (d) to ensure that there be opportunities for timely and meaningful public participation throughout the environmental assessment process.

The intent of the CEA Act clearly supports the principle of early and meaningful public participation. The requirements of the CEA Act regarding public participation for panel reviews, for which the NEB public hearing process is a substitute for this Project, are as follows:

* every assessment by a review panel of a project shall include a consideration of ... comments from the public ... (paragraph 16(1)c of the CEA Act)
* a review panel shall: ensure that the information required for an assessment by a review panel is obtained and made available to the public (subsection 34(a) of the CEA Act); hold hearings in a manner that offers the public an opportunity to participate in the assessment (subsection 34(b) of the CEA Act); prepare a report setting out ... a summary of any comments received from the public ... (paragraph 34(c)ii of the CEA Act)
* a hearing by a review panel shall be public unless ... (subsection 35(3) of the CEA Act)

* regarding public notice ... the Minister shall make the report available to the public in any manner the Minister considers appropriate to facilitate public access to the report, and shall advise the public that the report is available (section 36 of the CEA Act).

5.2 Key Elements of Meaningful Public Participation

The public should be afforded an opportunity to provide their views to decision-makers, by participating in a meaningful public process, before decisions are made that affect their lives. For a public participation process to be meaningful, the CEA Agency recommends that it should exhibit all of the following elements:

* **Early notification** - Where notification is to be given, it needs to be done early enough to allow the public to have the opportunity to influence the planning of a project and its EA process before any irrevocable decisions are made.
* **Accessible information** - The RA should ensure that all participants are provided with the information they need to participate effectively on a timely basis. Consideration should be given to the appropriate language for this information and the need to use culturally-sensitive means of communication. Access to information should only be limited in accordance with the laws relating to access to information and privacy.
* **Shared knowledge** - A project should be developed on the basis of both technical and scientific knowledge, and community and Aboriginal traditional knowledge. Knowledge, concerns, values and viewpoints should be shared in an open, respectful and timely manner. This includes information on the potential consequences of a project. Any rights flowing from the ownership of information that participants may have need to be respected.
* **Sensitivity to community values** - Public participation processes need to be carried out in a manner that respects different community values and needs.
* **Reasonable timing** - A public participation process should provide the public with a fair and reasonable amount of time to evaluate the information presented and to respond to project proposals and to proposed decisions by proponents and RAs.
* **Appropriate levels of participation** - A public participation process should provide for levels of participation that are commensurate with the level of public interest.
* **Adaptive processes** - Public participation processes should be designed, implemented and revised as necessary to match the needs and circumstances of the project and to reflect the needs and expressed preferences of participants. This process may be iterative and dynamic in keeping with the reasonable expectations of participants.

* **Transparent results** - Public participation is based on the premise that the public's contribution will be considered in the decision-making process. A public participation process should, at its conclusion, provide information and a rationale on whether or how the public input affected the decision.

5.3 Engagement Activities by EBPC

EBPC submitted that it conducted an extensive consultation program, commencing in mid-2005. EBPC stated that its consultation efforts would not stop with the selection of the corridor or filing of the application, but that it would continue through the development of the detailed route within the preferred corridor, and the operations phase of the Project. The goals of the ESEA (including corridor selection) consultation program for the Project, as stated by EBPC, were to:

* identify stakeholders who have interests in the Project area and who could potentially be affected by the Project as soon as practicable in the planning phase of the Project;
* inform potential stakeholders throughout the various phases of the Project by sharing information on key project specifics in a clear and timely manner;
* create opportunities for meaningful input and advise stakeholders of their opportunities to communicate with EBPC or regulatory agencies if they so desire;
* understand and respond to any issues or concerns in an effort to ensure those issues or concerns are resolved or mitigated to the extent practicable; and
* identify communications with stakeholders leading up to the construction phase with a view to developing the long-term relationships required during project construction, and operation and maintenance.

Regulatory Consultation

EBPC indicated that a number of federal and provincial regulatory agency experts were contacted during the initial project scoping and corridor selection process to contribute expert advice, identify major constraints and important factors to be considered, or to express concerns regarding the Project with respect to their specific mandates. The corridor alternatives, constraints, and evaluation criteria were reviewed with local regulators, including DFO, EC, and NBDOE. Initial process discussions on the Project were also initiated with the NEB, the CEA Agency, and the NB Department of Energy. EBPC submitted that these consultations will continue throughout the regulatory approval process for the Project.

Public Consultation

According to EBPC, consultation with the public is required to fulfill EBPC's vision for consultation and to obtain regulatory approval for the Project. In the context of this Project, public consultation was directed at providing information to, and obtaining feedback from, interested parties, members of the public and potentially affected landowners on the selection of a preferred corridor and corridor alternatives. A variety of techniques were used to provide information to the public and to elicit feedback about the Project, including:

* open houses;
* questionnaires;
* newspaper advertisements;
* radio spots;
* a 1-800 phone number;
* an e-mail address;
* a Project website;
* newsletters, including a corridor map delivered to every mailing address in Saint John and the communities along the proposed corridor;
* site visits; and
* one-on-one and group meetings.

The geographic region included in the public consultation program covered the area between the Canaport[TM] LNG Terminal on Mispec Point in Saint John, NB to the international border near St. Stephen, NB. Communities within 10 km of the preliminary preferred corridor were solicited to participate in the open houses and public consultation program for the Project. EBPC stated that it attempted to ensure that all those located within the corridor were contacted directly, while those located beyond the corridor would receive general public notification, including open houses, mailings and other commonly-used means of notification. EBPC submitted that stakeholder groups with an interest in the Project were identified, and potentially affected landowners in the area were provided with information on the Project and encouraged to participate in the open houses.

Three open houses were held for the Project in late September 2005 in three NB communities along the preliminary preferred corridor. A fourth open house was held in Saint John in early December 2005 in response to requests for an additional consultation opportunity to focus on the urban section of the corridor, particularly Rockwood Park, and to provide the public with any new information on the preliminary preferred corridor obtained since the previous open houses. During the summer of 2006, three community meetings and walk-arounds were held (Milford, Millidgeville and Champlain Heights) at the request of the general public and their elected leaders.

Stakeholder Consultation

EBPC submitted that numerous meetings were held with key stakeholders (e.g., community groups, commercial landowners with large tracts of property that may be affected, or parties with an interest in lands that would be intersected by the pipeline corridor). These meetings are and would be continuing throughout the design and construction phases of the Project. The objective of these consultations was to provide a brief presentation on project activities and to solicit comments and concerns.

Aboriginal Consultation

According to EBPC, in order to meet the goals for Aboriginal consultation, an Aboriginal consultation plan and TEK study have been prepared and initiated for the Project. An Aboriginal consulting firm, Aboriginal Resources Consultants, was retained to facilitate the consultation process and the TEK plan. EBPC stated that the objectives of these efforts were:

* to respond to questions and concerns with regard to potential environmental effects to Aboriginal interests resulting from project activities;
* to inform the Aboriginal communities that the EA is one way to participate in the project approval process; and
* to gather information on the nature and extent of potential environmental effects on current land and resource use for traditional purposes.

The Aboriginal consultation plan was implemented to gather environmental and socio-economic information for use in the ESEA. The TEK study is ongoing and the information being gathered through this process will be used to enhance the detailed route process. As part of the Aboriginal consultation plan, open houses and direct consultation were identified as the primary forms of communication with First Nation communities and organizations. Through direct contact with the Chiefs, all 15 communities were given information about the Project and permission was requested to hold an open house in each of their communities. Of these, 13 agreed to allow the open houses. One community, Fort Folly, declined a session in their community (citing that any information would come from their Tribal council, the Union of New Brunswick Indians (UNBI))[50] and another, Buctouche, requested only a presentation to its council.

The report on the Aboriginal consulting process submitted by EBPC contained a number of recommendations based on the outcomes from direct consultation with the community Chiefs, participants at the open houses, and the two representative organizations (MAWIW Council[51] and UNBI). These are reproduced below (Aboriginal Resource Consultants, 2006):

* Provide copies of the consultation process report to each of the 15 NB First Nation communities.
* Provide to each of the NB First Nations a copy of the final ESEA, as well as the finalized ESEA map sets at the earliest opportunity.
* Develop specific detailed protocols, in concert with the organizational liaisons, addressing processes for the dissemination of information on employment and contracting opportunities, as well as a reporting process to measure results, and share them with the First Nation leadership of the 15 NB First Nation communities.
* Develop a detailed informational package on the Proponent's safety procedures and distribute to each of the NB First Nation communities.

EBPC was able to conclude formal agreements with both the UNBI and the MAWIW Council prior to the commencement of the oral portion of the hearing. The agreements include provisions for environmental monitoring and protection of Aboriginal heritage and cultural resources.

5.4 Engagement Activities by the NEB

The NEB encourages effective public participation in its public hearing process to allow people, who could be affected by a project, the opportunity to provide their views to the Board before the Board makes a decision about a company's application for a project. Some people may be in favour of a project, others may be against it, and some people may be uncertain of what the presence of a project might mean to them. It is important that all of these points of view are heard so that the Board can make a fully-informed regulatory decision.

To provide an opportunity for public participation in this NEB public hearing process, the NEB undertook a number of activities to identify issues and concerns of those potentially affected by the Project, to provide access to project information, and to facilitate participation.

Public Meetings

* 5 April 2006 - NEB staff held a public information session in Saint John. The purpose of this session was to share information about the NEB's role, responsibilities and mandate, and to explain how the public could become involved in the NEB's regulatory process.
* 5 June 2006 - NEB staff held an information session for UNBI in Oromocto. The purpose of this session was to share information about the NEB's role, responsibilities and mandate, and to explain how the public could become involved in the NEB's regulatory process.
* 19 and 20 June 2006 - NEB staff held public information sessions in Saint John. The purpose of these sessions was to assist individuals in selecting a method of participation and preparing for effective and meaningful participation in the public hearing process for the Brunswick Pipeline Project.
* 12 October 2006 - The NEB panel and staff held pre-hearing planning sessions in Saint John. The sessions were designed to assist parties in their preparation for the NEB public hearing on the Brunswick Pipeline Project, and to invite Intervenor feedback to assist in the planning for the oral portion of the hearing.

Communications

* When the decision to hold a public hearing was made, a hearing notice was issued on 9 June 2006. It was published in the newspapers that have the largest circulation in the areas most affected by the Project, as well as in the *Canada Gazette.* The notice outlined the subject of the hearing, where and when it would be held and how a copy of Hearing Order GH-1-2006 could be obtained.

* Invitation to the first public information session held by the Board was advertised in local newspapers; notice was provided in the Hearing Order or directly to participants for the other sessions.
* All parties to the hearing and individuals who requested to make an oral statement received notice by mail of the pre-hearing planning sessions.
* NEB staff answered numerous procedural questions via telephone inquiries.
* The Board issued a document called "What Can I Expect at the Hearing?" that provided definitions and explanations on the hearing process in order to assist Intervenors and Government Participants.
* The hearing was audio broadcast live from Saint John, which allowed the public and the parties to the hearing to follow the proceedings without having to travel and attend the hearing.
* Hard copies of exhibits were available in the hearing room, with a computer and printer available for public use.
* Transcripts of the oral hearing, in hardcopy and electronic form, were made available after each day of the proceeding.

Public Access to Documents

* The NEB requested that EBPC make available for public viewing, at six locations, all documents relating to this application and public hearing process.
* Electronic copies of documents issued by the NEB and parties to the hearing, and letters of comment were available at the National Energy Board's Website (www.neb-one.gc.ca).

These activities were designed to facilitate effective public participation in the EA and the NEB public hearing process. Persons potentially affected by the Project were given the opportunity to participate, either in full or in part, in the public hearing. Members of the public could participate in this hearing in one of three ways - by filing a letter of comment on the Project, by providing an oral statement or by seeking Intervenor status. The procedure for becoming a participant was described in Hearing Order GH-1-2006.

There were 72 Intervenors and three government participants in the NEB hearing, all of whom were provided the opportunity to present evidence, conduct cross-examination and make final arguments. The letter of comment option was intended to allow interested persons who did not wish to appear at the hearing an opportunity to provide their views and opinions on the Project. There were 184 letters of comment filed in this proceeding. The oral statement option was intended to allow interested persons who did not wish to intervene an opportunity to give their views to the Board. There were 19 oral statements presented during the oral portion of the hearing. In addition, written evidence was filed, there was an information request process, the oral portion of the hearing extended over 13 days, and written final argument was filed.

5.5 Summary of Public Comments

Comments from the public were received during the NEB public hearing process in a variety of ways:

* through information provided by EBPC about the results of its consultation program;
* via letters of comments; and
* through written and oral presentations of information during the proceeding.

Many members of the public provided comments with respect to public safety, including concerns about:

* consequences of an accident or malfunction, including malfunctions resulting from vandalism or terrorism, on public safety;
* emergency access to and from communities in the event of an accident or malfunction;
* capacity of first responders and the hospital in the event of accidents or malfunctions; and
* psychosocial health impacts related to anxiety and stress.

Many people also expressed concerns about the Project crossing through Rockwood Park. These concerns included:

* industrial development occurring on land designated for use as a park;
* environmental effects from the Project in Rockwood Park, such as effects on surface water, wildlife, caves; and,
* effects to recreational use of the Park.

The NEB also received comments regarding specific environmental effects of the Project, including concerns about:

* environmental effects to the Loch Alva Protected Natural Area and environmentally significant areas;
* off-road vehicle access along the RoW;
* effects on water resources in the urban area;
* urban wildlife;
* greenhouse gas (GHG) emissions;
* air emissions and tree removal with the potential to affect air quality;
* interference with land use; and
* effects on blueberry fields in Milford area.

Comments about socio-economic issues included concerns about:

* property damage resulting from pipeline construction;
* noise;
* disruptions in the City, e.g., traffic, dust, disturbance to zoo;
* health effects from dust; and,

* development of one pipeline leading to future development of more pipelines.

Many individuals indicated opposition to a route through the City and Rockwood Park, and near occupied buildings, such as schools, the hospital, and residences, but would accept or support a marine route for the pipeline.

Some comments were received in support of the Project, based on potential economic benefits to the community, benefits of natural gas supply and confidence in the Applicant's ability to meet environmental and safety standards.

The Board has given due consideration to all comments raised throughout this proceeding. For consideration under the CEA Act, public comments must be related to the likely environmental effects of the proposed Project. The comments and concerns that relate to the Board's CEA Act mandate have been considered in the preparation of this EA Report.

In addition, the Board received comments on a number of other matters. Those comments that relate to matters that may be more appropriately considered under the Board's mandate under the NEB Act will be considered in the Reasons for Decision to be issued at a later date. These included concerns about:

* lack of benefits to the City and citizens of Saint John;
* effects on property value and property insurance rates resulting from proximity to the Project;
* interference with future property developments;
* costs to the City resulting from the Project, such as from effects on City infrastructure;
* the consultation program conducted by M&NP and then EBPC and a general lack of information about the Project;
* corporate social responsibility of companies associated with the Proponent (Nova Scotia Power, Repsol);
* lack of consultation with the Passamaquoddy;
* the need for the Project, the economic feasibility of the Project; and potential commercial impacts of the Project; and
* consideration of alternative routes for the Project (e.g., a marine crossing).

Other comments received from the public include concerns about:

* the LNG Terminal and the pipeline Project have not been assessed together as one project; and
* environmental effects from the LNG Terminal and LNG tanker activity.

The comments regarding consideration of the LNG Terminal and LNG tanker activity have been addressed in the Board's ruling on scope in Appendix 4 and are discussed further in section 7.3.

Views of the Board

The Brunswick Pipeline Project marks the first time that the NEB's public hearing process has been substituted for an EA by a review panel under the CEA Act. Throughout the process, considerable effort has been focused on ensuring that the requirements of the CEA Act regarding public participation have been met. The Board greatly appreciates the participation of the public in the EA of the proposed Project, and is of the view that the NEB public hearing process has fulfilled the public participation requirements of the CEA Act for review panels.

Paragraph 16(1)(c) of the CEA Act states that every assessment by a review panel of a project shall include a consideration of comments from the public. The Board has taken into consideration comments from the public in assessing the proposed Project. For example, in assessing the environmental effects of the Project, the Board used an issue-based approach, which relied on the identification of issues by both technical experts and by people who could be affected by the pipeline.

Subsection 34(a) of the CEA Act states that a review panel shall ensure that the information required for an assessment by a review panel is obtained and made available to the public. The Board notes that the information required for the EA was made available to the public. This information could be accessed through a variety of means, including:

* documents relating to this application and public hearing process were available for public viewing at six Saint John locations and at the oral portion of the public hearing;
* electronic copies of documents were available on the NEB's Website;
* EBPC attempted to ensure that all those located within the corridor were contacted directly and provided with information on the Project; and
* 15 First Nation communities were given information about the Project. Subsection 34(b) of the CEA Act states that a review panel shall hold hearings in a manner that offers the public an opportunity to participate in the assessment. For this Project, the public was given an opportunity to participate in the NEB public hearing process in a variety of ways (e.g., Intervenors, letters of comment, oral statements). The Board acknowledges and appreciates the time and effort the public devoted to the process and the personal contributions they made.

Paragraph 34(c)(ii) of the CEA Act states that a review panel shall prepare a report setting out a summary of any comments received from the public, and the Board notes that section 5.5 of this Report provides a summary of public comments. Subsection 35(3) of the CEA Act states that a hearing by a review panel shall be public, and the Board notes that the NEB public hearing process was open to the public.

Regarding the intent of the CEA Act to clearly support the principle of early and meaningful public participation, the Board notes that several members of the public have argued that project consultation was inadequate. With respect to early public participation, the Board is satisfied that the consultation program commenced in a timely manner as it was initiated shortly after the precedent agreement was signed between M&NP and Repsol in July 2005. With respect to meaningful public participation, claims from members of the public suggest that EBPC and the NEB could have done a better job in relation to the key elements of meaningful public participation. In accordance with the philosophy of continuous improvement, the Board is interested in learning from its first substituted public hearing process. Section 8 of this Report provides a summary of the Board's comments on the substitution process and identifies potential areas that could be enhanced. While recognizing that certain areas could have been improved, the Board is satisfied that EBPC and the NEB public hearing process have met the requirements for public participation under the CEA Act.

An evaluation of EBPC's consultation program undertaken pursuant to the guidelines set out in the NEB's Filing Manual, including but not limited to consultation activities related to environmental matters, will be included in the Board's Reasons for Decision issued pursuant to its mandate under the NEB Act. The evaluation in the Reasons for Decision will provide a more comprehensive assessment of the consultation program, including consideration of the comments and concerns raised by participants.

6.0 METHODOLOGY OF THE NEB'S ENVIRONMENTAL ASSESSMENT

Factors Being Assessed

Section 6.0 outlines the methodology used in the NEB's EA analysis in section 7.0 of this Report. The section 7.0 analysis considers the following factors from the scope of the EA.

1. The environmental effects of the Project, including the environmental effects of malfunctions or accidents that may occur in connection with the Project and any cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out;
2. the significance of the effects referred to in paragraph 1;
3. comments from the public that were received during the public review; and
4. measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project.

Baseline Information and Sources:

The analysis for this EA Report is based on:

* EBPC's application, supplementary evidence and responses to information requests;
* evidence submitted by other parties to the hearing and associated responses to information requests;
* testimony provided at the oral portion of the hearing, including that provided in oral statements; and
* letters of comment received.

For more details on how to access or obtain the documents and information upon which this EA is based, please contact the Secretary of the Board at the address specified in section 10.0 of this Report.

Methodology of the Analysis:

In assessing the environmental effects of the Project, the NEB used an issue-based approach to fulfill the requirements of the CEA Act. Environmental effects are defined in the CEA Act, in respect of a project, as

(a) any change that the project may cause in the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species as those terms are defined in section 2(1) of the *Species at Risk Act (SARA)*, (b) any effect of any change referred to in paragraph (a) on health and socioeconomic conditions, on physical and cultural heritage, the current use of lands and resources for traditional purposes by Aboriginal persons, or any structure, site or thing that is of historical, archaeological, paleontological or architectural significance, or (c) any change to the project that may be caused by the environment.

In its analysis within section 7.1, the NEB identified interactions expected to occur between the proposed project activities (identified in section 2.3) and the surrounding environmental elements. Environmental effects were classified as either adverse or positive.

Based on guidance from the CEA Agency (1994), key factors that can be considered for determining adverse environmental effects include:

* adverse environmental effects on the health of biota;
* loss of rare or endangered species;
* reductions in biological diversity;
* loss or avoidance of critical/productive habitat;
* fragmentation of habitat or interruption of movement corridors and migration routes;
* transformation of natural landscapes;
* discharge of persistent or toxic chemicals;
* toxicity effects on human health;

* loss of, or detrimental change in, current use of lands and resources for traditional purposes; foreclosure of future resource use or production; and
* adverse environmental effects on human health or well being.

A positive environmental effect is one that:

* improves ambient air quality or reduces ambient sound pressure levels;
* improves quantity or quality of water resources;
* increases indigenous plant or wildlife species populations or diversity, or enhances or increases the area of habitat for indigenous species;
* enhances the quality, the indigenous species' diversity, or the area of a wetland;
* decreases the likelihood (from present conditions) that a serious injury or loss of life could arise;
* enhances land and resource use for residential, commercial, public, forestry, agricultural or recreational use; or
* enhances understanding of local, regional, or cultural heritage through increased knowledge, or provides physical protection for a site that might otherwise have been destroyed through natural or non-project events, in the absence of the Project.

Also included in this EA was the consideration of potential accidents and malfunctions that may occur due to the Project and any change to the Project that may be caused by the environment.

If there were no expected interactions between the Project and the environmental element then no further examination was deemed necessary. Similarly, no further examination was deemed necessary for interactions that would result in positive potential effects. In circumstances where the potential effect was unknown, it was categorized as a potential adverse environmental effect. All potential adverse effects that were identified underwent further analysis in either section

7.2.3 or section 7.2.4.

Section 7.2.3 provides an analysis for all potential adverse environmental effects that are normally resolved through the use of standard design or routine mitigation measures. In these cases, mitigation measures are outlined or explanations are provided as to why mitigation measures are not required.

Section 7.2.4 provides a detailed analysis for each potential adverse environmental effect that generated particular public concern, involves non-standard mitigation measures, monitoring or follow-up programs, or requires the implementation of an issue-specific recommendation. The analysis specifies those mitigation measures, monitoring and/or follow-up programs, views of the NEB and any issue-specific recommendations and ratings for criteria used in evaluating significance.

The CEA Act requires that significance of environmental effects be considered as part of the EA, but does not define a "significant environmental effect". The CEA Agency (1994) provides guidance on determining whether an adverse environmental effect is significant. It suggests that environmental standards, guidelines, and objectives are often used to determine significance. Where threshold standards or guidelines do not exist, other methods may be needed. The CEA Agency suggests that criteria for determining significance include magnitude, geographic extent, duration and frequency, irreversibility and ecological context. Criteria for determining likelihood include probability of occurrence and scientific uncertainty.

Table 6.1, below, defines the criteria used by the NEB for evaluating the significance of the effects discussed in section 7.2.4. These criteria are largely based on criteria submitted by EBPC. However, where EBPC's criteria were unclear, in particular in the category of frequency, the NEB adopted other criteria to provide more clarity to its evaluation. "Significant" environmental effects would typically involve environmental effects that are a combination of several of high frequency, irreversible, long term in duration, large in extent, or high magnitude.

Table 6.1 - Significance Criteria Definitions

Criterion: Frequency.

Definition: Low: at sporadic intervals during one phase of the project lifecycle Medium: continuous during one phase of the project lifecycle High: continuous throughout all phases of the project lifecycle

Criterion: Duration

Definition:

1 = [less than] 1 month

2 = 1-12 months

3 = 13-36 months

4 = 37-72 months

5 = [greater than] 72 months

Criterion: Reversibility

Definition: Reversible: effect is not permanent; Irreversible: effect is permanent.

Criterion: Geographic Extent

Definition:

1 = [less than] 1 km[superscript 2]

2 = 1-10 km[superscript 2]

3 = 11-100 km[superscript 2]

4 = 101-1000 km[superscript 2]

5 = 1001-10 000 km[superscript 2]

6 = [greater than] 10 000 km[superscript 2]

Criterion: Magnitude

Definition:

For atmospheric environment

Low: within normal variability of baseline conditions

Medium: increase/decrease with regard to baseline but within regulatory limits and objectives

High: singly or as a substantial contribution in combination with other sources causing exceedances or impingement upon limits and objectives beyond the project boundary

For water resources

Low: affecting the available quantity or quality of water resources at levels that are indiscernible from natural variation

Medium: limiting the available quantity or quality of water resources, such that these resources are occasionally rendered unusable to current users for periods up to two weeks at a time

High: limiting the available quantity and quality of water resources, such that these resources are rendered unusable or unavailable for current users during the life of the Project or for future generations beyond the life of the Project

For fish and fish habitat, vegetation, wetlands, wildlife and wildlife habitat

Low: localized environmental effect on a specific group, habitat, or ecosystem, returns to pre-project levels in one generation or less, within natural variation

Medium: portion of a population or habitat, or ecosystem, returns to pre-project levels in one generation or less, rapid and unpredictable change, temporarily outside range of natural variability

High: affecting a whole stock, population, habitat or ecosystem, outside the range of natural variation, such that communities do not return to pre-project levels for multiple generations

For health and safety

Low: no environmental effects beyond accident location, no lost time injuries, affecting only those involved in the accident, malfunction, or unplanned event.

Medium: environmental effects temporarily beyond accident location, lost time injuries, affecting persons not directly involved in the accident, malfunction, or unplanned event.

High: long-term environmental effects at or beyond accident location, serious injury or loss of life, affecting regional population.

For land and resource use

Low: specific group, residence or neighbourhood affected such that adjacent land use activities will be disrupted and current activities cannot continue even after short periods of time.

Medium: part of a community affected such that adjacent land use activities will be disrupted such that current activities cannot continue for extended period of time longer than two years.

High: community affected such that adjacent land use activities will be disrupted such that current activities cannot continue for extended periods of time longer than two years and are not compensated for.

For archaeological and heritage resources

Low: minor impairments to cultural resources appreciation or environmental effects to non-significant historic period heritage feature, e.g., stone fence line, field stone pile; loss of individual artifact.

Medium: loss of historic or cultural resources not of major importance, or predisturbed heritage site/artifacts present, however, no or little chance of intact features.

High: intact "significant" heritage site, pre-contact and/or contact period, features present, portion or all of site will be destroyed or lost.

Section 7.3 addresses cumulative effects, section 7.4 addresses capacity of renewable resources, section 7.5 addresses follow-up programs and section 9.2 lists recommendations for any subsequent regulatory approval of the Project.

7.0 ENVIRONMENTAL EFFECTS ANALYSIS

Table 7.1 Project - Environment Interactions

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Biophysical	Soil and Soil Productivity	Y	▪ Grubbing, topsoil stripping and compaction during construction activities	Adv	▪ Loss of soil capability to support vegetation	▪ Section 7.2.1 ▪ Table 7.2.3
	Vegetation	Y	▪ Clearing and grubbing for site preparation ▪ Installation of watercourse crossings ▪ Construction of temporary ancillary structures and facilities ▪ Vegetation control along pipeline RoW during pipeline operation ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Loss of vegetation and change in quality of habitat for vegetation ▪ Potential for invasive species to become established ▪ Potential loss of Species at Risk or Species of Conservation Concern	▪ Section 7.2.1 ▪ Table 7.2.3 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2 ▪ Species at Risk or Species of Conservation Concern are addressed in Table 7.2.4.1

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Biophysical	Water Quality and Quantity	Y	▪ Blasting of rock ▪ Ground disturbance and equipment traffic at project sites ▪ Trench excavation ▪ Watercourse crossings ▪ Water withdrawal for hydrostatic testing of pipeline ▪ Herbicide application for vegetation control during operations and maintenance ▪ Presence of pipeline trench ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Alteration of water well yields from blasting and other construction activities ▪ Sedimentation of shallow wells and watercourses ▪ Degradation of water quality from acid generated from sulphide-bearing rock (acid rock drainage) ▪ Temporary lowering of surface water levels or nearby well yields from water withdrawal for hydrostatic testing ▪ Change in physical or chemical quality of water resources from discharge of test waters, exposed contaminated soils, hazardous materials spills, or herbicide application ▪ Change in water flow systems from presence of pipeline trench	▪ Section 7.2.1 ▪ Table 7.2.3 ▪ Effects from acid rock drainage are addressed in Table 7.2.4.3 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2
	Fish and Fish Habitat	Y	▪ Installation of pipeline through watercourses ▪ Blasting in or near waterbodies ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Change in surface water and fish habitat quality ▪ Direct mortality of fish species ▪ Potential loss of Species at Risk or Species of Conservation Concern	▪ Section 7.2.1 ▪ Table 7.2.3 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2 ▪ Species at Risk or Species of Conservation Concern are addressed in Table 7.2.4.1

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Biophysical	Wetlands	Y	▪ Site preparation and construction activities in or near wetlands ▪ Exposure of sulphide-bearing rock from excavation and trenching ▪ Seeding along RoW near wetlands during site reclamation after construction ▪ Herbicide use for vegetation control during operations ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Loss of wetland function from a change in wetland quality or quantity from site preparation, pipe installation and site restoration activities ▪ Acidification of wetland from exposed sulphide-bearing rock ▪ Establishment of invasive species of vegetation in wetlands ▪ Potential for alteration of wetland habitat quality from use of herbicides	▪ Section 7.2.1 ▪ Effects from acid rock drainage are addressed in Table 7.2.4.3 ▪ Loss of wetland function is addressed in Table 7.2.4.4 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2
	Wildlife and Wildlife Habitat	Y	▪ Vegetation removal during clearing ▪ Noise from blasting activities ▪ Trenching and pipeline installation ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Habitat fragmentation ▪ Change in quality of habitat for wildlife ▪ Direct mortality of wildlife ▪ Potential loss of Species at Risk and Species of Conservation Concern ▪ Increased access to wildlife habitat along RoW	▪ Section 7.2.1 ▪ Table 7.2.3 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2 ▪ Species at Risk or Species of Conservation Concern are addressed in Table 7.2.4.1
	Species at Risk (federal) and Species of Special Status (provincial, territorial, local)	Y	▪ Disturbance of Species at Risk or Species of Conservation Concern and associated habitat throughout construction	Adv	▪ Potential loss of Species at Risk or Species of Conservation Concern ▪ Potential loss of critical habitat for Species at Risk or Species of Conservation Concern	▪ Section 7.2.1 ▪ Table 7.2.4.1

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Biophysical	Air Quality	Y	▪ Emissions from vehicles and equipment during construction ▪ Dust from blasting activities ▪ Fugitive emissions from pipeline during operation	Adv	▪ Change in local air quality during construction ▪ Release of methane during operations into atmospheric environment	▪ Section 7.2.1 ▪ Table 7.2.3
Socio-economic	Heritage Resources	U	▪ Construction could interact with previously unidentified heritage resources ▪ Construction could interact with identified heritage resources	Adv	▪ Disturbance to, or destruction of, heritage resources	▪ Section 7.2.1 ▪ Table 7.2.4.7
	Human Health/ Aesthetics	Y	▪ Increased noise levels in Milford and Pokiok, associated with HDD activities, could disrupt nearby residents	Adv	▪ Noise impacts on residents of Milford and Pokiok	▪ Section 7.2.1 ▪ Table 7.2.4.8
		Y	▪ Elevated noise emissions (including vibrations) during construction (including blasting) near buildings or residents	Adv	▪ Increased noise levels from construction activities with potential for disturbance along the RoW ▪ Property damage from vibrations during construction	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Unauthorized access to the RoW during construction	Adv	▪ Injuries to the public	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Increased air emissions and dust during construction (refer to Air Quality section above for additional details)	Adv	▪ (addressed in the Air Quality section above)	

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Socio-economic	Human Occupancy/ Resource Use	Y	▪ Construction activities in Rockwood Park could interfere with recreational pursuits	Adv	▪ Disruption to recreational pursuits in Rockwood Park	▪ Section 7.2.1 ▪ Table 7.2.4.6
		Y	▪ Restoration and future improvements to Rockwood Park could enhance recreational pursuits	P	▪ No adverse environmental effect	▪ Effect not discussed further
		Y	▪ Construction activities could interfere with recreational use	Adv	▪ Temporary restrictions on water-courses deemed navigable ▪ Temporary restricted access to hunting, fishing, biking and ATV use locations, and other recreational areas	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Construction activities and existence of the pipeline could interact with agricultural land use	Adv	▪ Disruption of agricultural operations	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Construction activities could result in disruption to traffic flow, which in turn could interfere with access to residences and businesses	Adv	▪ Traffic interruptions	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Construction activities could impact the quality and quantity of potable water (refer to Water Quality and Quantity section above for additional details)	Adv	▪ (addressed in Water Quality and Quantity section above)	

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Seocio-economic	Social and Cultural Well-being	U	▪ The operation of the pipeline may increase safety concerns of residents in close proximity to the pipeline	Adv	▪ Increased stresses on residents	▪ Section 7.2.1 ▪ Table 7.2.3
	Traditional Land and Resource Use	U	▪ Construction in areas currently used by Aboriginal persons for hunting, fishing, trapping and gathering ▪ Unauthorized access along RoW by ATVs or other motorized vehicles	Adv	▪ Effects on the current use of lands and resources for traditional purposes by Aboriginal persons, such as hunting, fishing, trapping, gathering	▪ Section 7.2.1 ▪ Effects from unauthorized access to RoW are addressed in Table 7.2.4.2 ▪ Disruption of current use of lands is addressed in Table 7.2.4.9
Other	Accidents/ Malfunctions	Y	▪ Hazardous materials spill during construction or operation from equipment refueling or malfunction ▪ Sediment control failure ▪ Temporary watercourse crossing washout during construction ▪ Accidental fire ignited during construction activities	Adv	▪ Contamination of soil and water resources ▪ Sedimentation of watercourses ▪ Damage to vegetation and to wildlife habitat, and reduced air quality, in the event of a fire	▪ Section 7.2.1 ▪ Table 7.2.3
		Y	▪ Pipeline rupture or leak during operation, and potential ignition of gas	Adv	▪ Direct mortality to humans, wildlife and vegetation in the area in the event of a fire	▪ Section 7.2.4.10

	Environmental element	Project interaction? Y/N/U	Description of interaction (How, When, Where)	Type of potential effect P/Adv	Potential adverse environmental effect	Effects and mitigation measures
Other	Effects of the Environment on the Project	U	▪ Weather (severe rainfall and flooding) ▪ Seismic activity (earthquakes) ▪ Sinkholes ▪ Induced potential	Adv	▪ Erosion of pipeline cover during operation from severe rainfall or flooding ▪ Damage to pipeline from seismic activity ▪ Damage the pipeline through subsidence related to a sinkhole ▪ Danger to personnel and damage to coatings and pipe from fault currents resulting from lightning or upset conditions of electrical facilities inducing electrical potential in the pipe	▪ Section 7.2.1 ▪ Table 7.2.3

Legend: Y (Yes); N (No); U (Uncertain); P (Positive); Adv (Adverse)

7.2 Potential Adverse Environmental Effects

7.2.1 Environmental Management Framework

To mitigate and manage the potential adverse environmental effects of the Project, EBPC indicated that it would implement its Environmental Management Framework. The Project's Environmental Management Framework would be comprised of the following major program components:

- a Pipeline Design and Quality Assurance Program;
- an Environmental Protection and Safety Management Program;
- an Emergency Preparedness and Response Program; and
- a Public Awareness Program.

The Project would be designed in accordance with the design criteria, specifications, programs, manuals, procedures, measures, and plans identified in the Canadian Standards Association (CSA) Z662 standard. A quantitative risk analysis (Bercha International Inc., 2005) was conducted on the proposed pipeline consistent with the risk assessment guidelines established in the CSA Z662 standard. A Quality Assurance Program would be implemented to ensure that the pipe and pipeline components used in construction of the pipeline meet the specifications provided for in the pipeline design to reduce the probability of material defects.

EBPC's Environmental Protection and Safety Management Program would include a construction safety manual and a maintenance safety manual to ensure work is performed safely and in accordance with applicable health and safety regulations. It would also include an environmental protection plan (EPP) for construction, based on the current policies and procedures, environmental management practices, and contingency plans of M&NP and Duke Energy Gas Transmission for pipeline projects. The EPP would include:

* roles and responsibilities for implementation of environmental protection measures, descriptions of major construction activities and a definition of their sequence;
* qualifications and training requirements for personnel implementing the EPP;
* a definition of major construction activities and definition of their sequence, as well as the mitigation measures and applicable procedures to be implemented for various construction activities;
* measures to minimize disruption to local communities as a result of construction;
* identification of the environmental resources present along the pipeline route and the specific mitigation measures to be implemented to protect these resources;
* a description of monitoring and follow-up measures to be implemented; and
* contingency and emergency response plans for accidents, malfunctions and unplanned events, such as hazardous spill response procedures, soil erosion and sediment control guidelines, fire response, plans in the event contamination sites are encountered, response plans for wildlife encounters, and procedures and guidance in the event a heritage, paleontological, or archaeological resource is encountered during construction.

EBPC stated that it would use a site inspection and monitoring program to ensure the effectiveness of EPP implementation, including having an inspector onsite to ensure compliance with the EPP. The inspector would work with project personnel to address environmental issues and take immediate action to address any work in non-compliance with the Environmental Protection and Safety Management Program, including stopping or relocating work if necessary.

The Environmental Protection and Safety Management Program would include other components; for example, comprehensive operation and maintenance manuals describing safe work plans and procedures and requirements for worker and contractor training related to health and safety. A Pipeline Integrity Management Plan would be prepared and implemented to detect pipeline defects and prevent pipeline ruptures. Routine pipeline monitoring and surveillance programs, including line patrol surveys, would be conducted to identify potential operation problems, security issues, and unauthorized activities on the RoW.

Audits and site inspections would be conducted to ensure that the Environmental Protection and Safety Management Program policies and procedures are being implemented effectively, deficiencies recorded, and corrective action taken.

The Emergency Preparedness and Response Program would be comprised of standards addressing emergency response training and the scope and frequency of emergency response exercises, continuing education programs for first responders and Emergency Planning Zone residents, and a formal liaison program for both lead and supporting government agencies. It would include a Field Emergency Response Plan.

A Public Awareness and Education Program would be implemented to alert the public of the requirements and restrictions associated with activities conducted in and around the pipeline RoW. The program would include ongoing communication and consultation.

Since the Environmental Management Framework described above applies to all management and mitigation of all potential environmental effects of the Project, the elements of the framework will only be discussed further in this EA Report in the context of those specific effects where elaboration is required.

In response to possible Certificate conditions issued by the Board for comment during the GH-1-2006 proceeding, EBPC expressed concerns about a possible condition that would require EBPC to specify, at least 30 days prior to construction, a detailed list of the number and type of each inspection position in its inspection program, including job descriptions, qualifications, roles, responsibilities, and decision-making authority. EBPC suggested that it would be unduly restrictive given the likelihood that construction inspection staffing levels, duties and responsibilities must be adjusted to accommodate the work flow, which is impacted by weather, landowner requirements, certain site-specific environmental matters and other unforeseen conditions.

Views of the Parties

Parties to the hearing provided few comments on EBPC's Environmental Management Framework in general. The vast majority of the comments made focused on EBPC's Emergency Preparedness and Response Program. These comments are addressed later in this Report, at section 7.2.4.10.

Views of the Board

The Board finds that EBPC's proposed Environmental Management Framework as described would be consistent with the *Onshore Pipeline Regulations, 1999* (OPR) and is appropriate.

The Board recognizes EBPC's concern that the details of its inspection program would need to be flexible in order to address conditions during construction. To address this concern while still providing the Board with information demonstrating the adequacy of EBPC's inspection program, the Board has amended the proposed condition that would be recommended should the Project receive regulatory approval, to require that EBPC file preliminary information about its program and how any changes to its program would be determined.

If the Project were to receive regulatory approval, the Board recommends that the following general conditions be attached to the Certificate.

* EBPC shall file with the Board for approval, at least sixty days prior to construction, a project-specific EPP. This EPP shall be a comprehensive compilation of all environmental protection procedures, mitigation measures, and monitoring commitments, as set out in EBPC's application for the Project, subsequent filings, evidence collected during the hearing process, or as otherwise agreed to during questioning or in its related submissions. The EPP shall describe the criteria for the implementation of all procedures and measures, and shall use clear and unambiguous language that confirms EBPC's intention to implement all of its commitments. Construction shall not commence until EBPC has received approval of its EPP from the Board.

The EPP shall address, but is not limited to, the following elements:

a. environmental procedures including site-specific plans, criteria for implementation of these procedures, mitigation measures and monitoring applicable to all project phases, and activities;
b. a reclamation plan which includes a description of the condition to which EBPC intends to reclaim and maintain the right of way once the construction has been completed, and a description of measurable goals for reclamation; and

c. evidence of consultation with relevant regulatory authorities that either confirms satisfaction with the proposed mitigation or summarizes any unresolved issues with the proposed mitigation.

* EBPC shall file with the Board for approval, at least thirty days prior to construction, a construction inspection program. The program shall include:

  a. a preliminary list of the number and type of each inspection position, including job descriptions, qualifications, roles, responsibilities, decision-making authority;
  b. a discussion of how any changes to the items outlined in (a) would be determined during the course of construction; and
  c. the reporting structure of personnel responsible for inspection of the various pipeline construction activities, including environment and safety.

* Within 6 months following commencement of operation of the Project, and on or before the 31st of January following each of the second (2nd) and fourth (4th) complete growing seasons following commencement of the operation of the Project, EBPC shall file with the Board a post-construction environmental report that:

  a. identifies on a map or diagram any environmental issues that arose during construction;
  b. provides a discussion of the effectiveness of the mitigation applied during construction;
  c. identifies the current status of the issues identified, and whether those issues are resolved or unresolved; and
  d. provides proposed measures and the schedule EBPC shall implement to address any unresolved issues.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations B, E, and O.

The Board expects that EBPC would include in its EPP all commitments made during the course of the GH-1-2006 proceeding. This includes all commitments made in response to comments or recommendation from other parties, including government departments. Through consultation with relevant regulatory authorities, the Board expects that any outstanding comments from government departments, such as EC, about mitigation measure details would be addressed in the development of the EPP for the Project.

7.2.2 Routing

One of the primary forms of mitigation of potential effects from pipeline projects is appropriate route selection. As discussed in section 3.3, EBPC considered various alternative routes for the Project and evaluated routing options based on criteria that included environmental constraints and minimizing disturbance through the use of existing corridors where practicable.

EBPC noted that three vegetation-based environmentally significant areas intersect with, or are located near, the preferred corridor. These areas are along the shores of rivers. The site where the preferred corridor would cross these rivers may be some distance from the biological feature for which the environmental significant area was established to protect. The preferred corridor also runs through the southern edge of the Loch Alva Protected area, which contains 21 925 ha of two neighbouring ecoregions.

EBPC indicated that detailed routing within the preferred corridor would be based on further site-specific constraint mapping, field investigations, and information received from the public, landowners, other interested parties, and government agencies. EBPC referred to avoidance of environmental features during detailed routing as a form of mitigation.

Views of the Board

The Board is satisfied that EBPC has selected an appropriate corridor with respect to minimizing adverse environmental effects and finds that EBPC has demonstrated a commitment to avoidance of environmental features in the final route selection process.

7.2.3 Analysis of Potential Adverse Environmental Effects to be Mitigated through Standard Measures

This section identifies proposed standard design or mitigation measures committed to by EBPC. These measures have been summarized in this section. The Board expects that detailed standard design or mitigation measures would be provided by EBPC in its EPP and other documents as part of its Environmental Management Framework as discussed in section 7.2.1.

Potential Adverse Environmental Effect: Loss of soil capability to support vegetation.

EBPC's Proposed Standard Design or Mitigation Measures:

* Avoid agricultural lands where practicable
* Compensate affected landowners during construction
* Suspend work in wet conditions
* Maintain soil layers
* Maintain a single travel path over agricultural lands.

Potential Adverse Environmental Effect: Loss of vegetation and change in quality of vegetation habitat.

EBPC's Proposed Standard Design or Mitigation Measures:

* Limit area of disturbance
* Avoid plant Species at Risk and Species of Conservation Concern by route selection
* Plan for watercourse crossings using NB Department of Environment and Local Government's (NBDELG) 2002 Watercourse Alteration Technical Guidelines
* Use erosion control measures
* Manage contaminated soils in accordance with the NBDELG's 2003 Guideline for Management of Contaminated Sites
* Limit use of herbicide during RoW maintenance, use herbicide of short persistence and low ecological toxicity, and follow manufacturer's guidelines for spraying.

Potential Adverse Environmental Effect: Potential for invasive species to become established.

EBPC's Proposed Standard Design or Mitigation Measures:

* Revegetate exposed soils with native vegetation to ensure long-term stabilization
* Seed mixes to be free of wee species to extent feasible
* Use cleaning stations for equipment and vehicles where required to reduce the spread and introduction of invasive species of plants.

Potential Adverse Environmental Effect: Alteration of water well yields from blasting and other construction activities.

EBPC's Proposed Standard Design or Mitigation Measures:

* Monitor wells and water supply lakes and rivers within 50 m of excavation
* Identify wells within 500 m of blasting
* Inspect wells within 100 m of blasting and identify low yield wells
* Collect water samples from wells closest to blasting
* Design blasts to minimize vibration
* Follow regulatory guidelines for blasting
* Remediate or replace permanently affected wells
* Provide temporary water supplies when required.

Potential Adverse Environmental Effect: Sedimentation of shallow wells and watercourses.

EBPC's Proposed Standard Design or Mitigation Measures:

* Use sediment and erosion control measures
* Treat or replace water supply if required
* Provide temporary water supplies if necessary.

Potential Adverse Environmental Effect: Temporary lowering of surface water levels or nearby well yields from water withdrawal.

EBPC's Proposed Standard Design or Mitigation Measures:

* Adjust water withdrawal procedures in accordance with watersource water levels.

Potential Adverse Environmental Effect: Change in physical or chemical quality of water resources from discharge of test waters, exposed contaminated soils, hazardous material spills, or vegetation control measures.

EBPC's Proposed Standard Design or Mitigation Measures:

* Minimize dewatering for hydrostatic testing by transferring water from one test section to another
* Return test waters to a vegetated area in the same watershed from which the water was taken
* Evaluate hydrostatic test waters qualitatively, and if required, sample and analyze for a set of indicative water quality parameters
* Take mitigation action if water quality parameters exceed the Canadian Council of Ministers of the Environment (CCME) Environmental Quality Guidelines
* Dispose of contaminated soils as per applicable permits and regulations
* Enforce a minimum setback from water resources for use of hazardous materials
* No chemical spraying of herbicides on the RoW, use only herbicides of low persistence and low ecological toxicity within the confines of the valve and metering sites
* Treat or replace water supply if required.

Potential Adverse Environmental Effect: Change in water flow systems from presence of pipeline trench.

EBPC's Proposed Standard Design or Mitigation Measures:

* Install groundwater flow barriers to prevent flow along trench
* Use backfill with hydrological properties that avoid alteration to groundwater flow

* Avoid placing high traffic work sites (e.g., marshalling or storage yards) in protected watersheds, slopes and recharge areas.

Potential Adverse Environmental Effect: Change in surface water and fish habitat quality. Direct mortality of fish.

EBPC's Proposed Standard Design or Mitigation Measures:

* Obtain DFO approval for blasting near/through watercourses
* Develop watercourse crossing plans using DFO and Watercourse Alteration Technical Guidelines
* Apply for, and follow requirements of, Watercourse and Wetland Alteration (WAWA) permit
* Use sediment and erosion control measures
* Limit area of disturbance, especially within 30 m of a watercourse
* For winter clearing, maintain a 30 m buffer zone at watercourse crossing locations
* Dispose of hydrostatic test waters within the same watershed from which water was obtained
* Test hydrostatic test waters for total suspended solids, metals and general water chemistry
* Monitor water discharge areas for erosion
* Monitor approach roads, abutments and bridge decks regularly; correct deficiencies immediately
* Minimize instream work, isolate work from the water flow where practicable
* Obtain DFO authorization for wet crossings, dry crossings, and in-stream blasting
* Use floating silt curtains and pump around for instream sediment control during wet crossings
* Instream equipment should be clean and inspected for drips and leaks prior to entering a watercourse and inspected regularly for leaks while instream
* Restore stream to preconstruction condition
* Contour, stabilize, armor and vegetate disturbed stream banks
* Adhere to DFO's harmful alteration, disturbance, or destruction of fish habitat (HADD) authorization conditions
* At the Dennis Stream: make every reasonable effort to use an isolated (dry) crossing method. If a wet crossing is required, use additional measures to limit sedimentation as outlined in EBPC's ESEA
* Designate fuel storage areas to be at least 100 m from watercourses
* Designate refueling areas to be at least 30 m from watercourses
* Use proper containment measures for hazardous materials storage tanks

* For annual maintenance activities involving travel along the length of the RoW, obtain permits to ford watercourses
* During operation, limit use of herbicides to station facilities, and use low toxicity, short persistence herbicides.

Potential Adverse Environmental Effect: Habitat fragmentation.

EBPC's Proposed Standard Design or Mitigation Measures:

* Locate RoW adjacent to other linear disturbances (e.g., SJL, IPL Route)
* Minimize RoW width and clearing to greatest extent practicable
* Minimize size of temporary workspaces
* Confine clearing and grubbing to RoW
* Minimize removal of shrubs and grubbing within 30 m of all streams
* Revegetate work areas.

Potential Adverse Environmental Effect: Change in quality of habitat for wildlife.

EBPC's Proposed Standard Design or Mitigation Measures:

* Retain surface soils for reinstatement following maintenance or repairs
* A WAWA permit would be obtained for any mechanical vegetation management within 30 m of a wetland greater than 1 ha or contiguous to a watercourse
* Manage contaminated soils in accordance with NBDELG's 2003 Guideline for Management of Contaminated Sites
* Avoid sensitive wildlife areas by route selection.

Potential Adverse Environmental Effect: Direct mortality of wildlife.

EBPC's Proposed Standard Design or Mitigation Measures:

* Check open trenches prior to backfilling for wildlife, such as wood turtles
* Minimize length of time that trenches are left open
* Erect fencing around boreholes and pits to protect wildlife
* Carry out RoW vegetation control to occur outside of the breeding season of bats
* Use manual and mechanical means of vegetation control along RoW; use chemical spraying only within the confines of graveled meter stations and other station facilities
* No chasing, harassing, or feeding wildlife by personnel
* Operate vehicles at appropriate speed and yield to wildlife

* Properly store and dispose of construction site wastes that might attract wildlife.

Potential Adverse Environmental Effect: Change in local air quality during construction.

EBPC's Proposed Standard Design or Mitigation Measures:

* Use dust suppressants, such as water, during periods of heavy activity and dry periods
* Follow equipment maintenance schedules
* Use low sulphur fuels where feasible
* Preserve natural vegetation where practicable
* Minimize activities that generate large quantities of dust during high winds.

Potential Adverse Environmental Effect: Release of methane during operations into atmospheric environment.

EBPC's Proposed Standard Design or Mitigation Measures:

* Use a regular preventive maintenance program, including a leak detection and repair program and cathodic protection system to prevent leaks
* During major maintenance activities, isolate the pipeline section to minimize natural gas released
* Ensure pipeline operations staff are trained on best practices to reduce methane emissions.

Potential Adverse Environmental Effect: Increased noise levels from construction activities with potential for disturbance along the RoW.

EBPC's Proposed Standard Design or Mitigation Measures:

* Use noise controls where warranted (e.g., sound barriers)
* Use timing restrictions where warranted
* Keep the equipment in good working order (with mufflers) and restrict construction activities to daytime hours (10-12 hours per day) where practicable
* Due to the relatively isolated location of the proposed HDD for the St. Croix River, EBPC did not anticipated that a considerable amount of noise reduction mitigation would be required at that location. However, the proximity of any new residences in the area would be reviewed prior to commencement of the HDD and noise mitigation would be reconsidered if there were new residences that

could be adversely affected by the noise created by the HDD activities.

* Noise associated with activities for the Saint John River HDD is addressed in section 7.2.4.8 Noise impacts on residents of Milford and Pokiok.

Potential Adverse Environmental Effect: Property damage from vibrations during construction.

EBPC's Proposed Standard Design or Mitigation Measures:

* Pre-blast surveys would be conducted for structures such as homes and cemeteries within a 200 m radius of planned blasting activities to ascertain baseline conditions and verify, with post-blast review, that blasting does not adversely affect these structures
* If there were an adverse effect on these structures, then EBPC would either rectify the damage, or compensate for it.

Potential Adverse Environmental Effect: Injuries to the public.

* Use blast mats to prevent flying debris
* The Construction Safety Manual would prescribe protective measures (e.g., preparation of safe work procedures, use of personal protective equipment) to mitigate potential hazards (e.g., noise, hazardous chemical handling and conventional construction hazards) and to ensure the Proponent's policy and applicable regulations are met (e.g., Canada Labour Code, *Transportation of Dangerous Goods Act* and *Regulations, Workplace Hazardous Materials Information System Regulations,* Environmental Protection and Safety Management Program)
* Use signage, natural barriers, fencing
* A comprehensive and detailed program to effectively restrict unsupervised access to the RoW during construction would be developed in consultation with the construction contractor. This plan has not yet been developed as the contractor would not be hired until early 2007. However, the following methods would be incorporated into the program: signage; 24-hour security; and notice to schools, churches, community centres and recreation users.

Potential Adverse Environmental Effect: Temporary restrictions on watercourses deemed navigable

EBPC's Proposed Standard Design or Mitigation Measures:

* Signage would be implemented warning boaters and fishers of work in progress in the project area

* Approval from the Minister of Transport (Transport Canada) under the *Navigable Waters Protection Act* would be obtained.

Potential Adverse Environmental Effect: Temporary restricted access to hunting, fishing, biking, ATV use locations, and other recreational areas.

EBPC's Proposed Standard Design or Mitigation Measures:

* Existing access across the RoW would be maintained during construction with only very minor temporary interruptions
* All trail systems, including the system in Rockwood Park, would only be partially affected in the vicinity of the construction activities and would be fully restored once construction is completed
* All areas to be affected by pipeline construction activities would be restored following the completion of construction and EBPC's anticipated that current recreational activities would resume after clean-up
* Shamrock Park may be used as a staging area for the Saint John River HDD; however, that work is planned for the winter of 2007/2008 when recreational use of the Park is limited and it is anticipated that the soccer and baseball fields would be restored for use in the summer of 2008.

Potential Adverse Environmental Effect: Disruption of agricultural operations.

EBPC's Proposed Standard Design or Mitigation Measures:

* The topsoil layers would be removed and piled separately during construction, and replaced during site restoration
* In any location where the topsoil has to be stored for extended periods, or over winter, it will be protected from wind and water erosion by covering it with hay mulch and seeding
* Farmers/landowners whose agricultural fields are within the eventually selected 30 m RoW would be compensated for lost production during the construction phase of the Project
* Areas with crop growth that are directly affected by construction activities may experience reduced crop yields for a brief period after construction. EBPC would work with farmers/landowners to monitor any residual crop loss and, if required, implement additional mitigation in order to return the land to its pre-construction capacity. Farmers/landowners would be compensated for reduced crop yields during this post-construction period.

Potential Adverse Environmental Effect: Traffic interruptions.

EBPC's Proposed Standard Design or Mitigation Measures:

* EBPC and its construction contractors would work with City officials and local law enforcement officials to minimize traffic interruptions and ensure that traffic continuity is maintained, if periodically slowed down
* A traffic management plan would be developed for the access areas to both HDD sites. The development of this plan may warrant consultation with City of Saint John officials
* Along major transportation corridors such as Route 1, or at corridors with high traffic volumes such as Rothesay Avenue, the pipeline would likely be installed by bore (i.e., placed under the road with no interruption to traffic)
* Any temporary traffic disruptions would be coordinated with the appropriate municipal or provincial authorities and would meet all applicable bylaws or regulations. At no time would access to any area be completely cut off. Alternate access, if required, would immediately follow pipeline installation.

Potential Adverse Environmental Effect: Increased stresses on residents.

EBPC's Proposed Standard Design or Mitigation Measures:

* EBPC woud develop and implement an Environment, Health & Safety Policy that establishes its commitment to protecting the environment, and ensuring the health and safety of its employees, customers and members of the public.
* An Environmental Management Framework, comprised of a Pipeline Design and Quality Assurance Program, an Environmental Protection and Safety Management Program, an Emergency Preparedness and Response Program, and a Public Awareness Program, would be implemented to ensure that the Proponent's Environment, Health & Safety Policy objectives are achieved. Specific plans and procedures would be prepared within this Environmental Management Framework to mitigate potential adverse environmental effects to public and woker health and safety identified from the assessment of project activities
* EBPC emergency planning, first responder training and public education would be subject to NEB requirements under the OPR and CSA Z731
* EBPC would engage the Saint John Fire Department (SJFD) and other first responders in southern NB in the development and finalization of an Emergency Response Plan. This plan would be com-

pliant with regulatory requirements and achieve the concurrence of the SJFD

* Higher grades of steel together with the thicker wall pipe would be used in built-up areas, which means that design parameters would exceed code requirements in many areas. This would give the Brunswick Pipeline a safety factor greater than that required by the applicable Codes
* EBPC's consultation efforts would continue through the development of the detailed route within the preferred corridor, and the operations phase of the Project.

Potential Adverse Environmental Effect: From accidents and malfunctions:

Contamination of soil and water resources

Sedimentation of watercourses

Damage to vegetation and to wildlife habitat, and reduced air quality, in the event of a fire.

EBPC's Proposed Standard Design or Mitigation Measures:

* Handle fuel and other hazardous material in compliance with the *Transportation of Dangerous Goods Act* and *Workplace Hazardous Materials Information System*, away from vulnerable areas
* Set out spill response procedures in the EPP and Field Emergency Response Plan
* Implement and inspect sediment and erosion control measures, with particular attention during and after extreme precipitation events, and take remedial action where necessary
* Use procedures to prevent fires, and train workers and contractors in fire prevention and response.

Potential Adverse Environmental Effect: Erosion of pipeline cover during operation from severe rainfall or flooding. Damage to pipeline from seismic activity.

EBPC's Proposed Standard Design or Mitigation Measures:

* Design pipeline in accordance with CSA Z662 Standard taking into account environmental stresses such as earthquakes
* Implement EBPC's Quality Assurance Program
* Include actions to respond to environmental perturbations in development of a Maintenance Safety Manual.

Potential Adverse Environmental Effect: Damage to the pipeline through subsidence related to a sinkhole

EBPC's Proposed Standard Design or Mitigation Measures:

* Complete a detailed geotechnical evaluation along the proposed RoW
* Avoid areas where subsidence or sinkholes are a concern.

Potential Adverse Environmental Effect: Danger to personnel and damage to coatings and pipe from fault currents resulting from lightning or upset conditions of electrical facilities inducing electrical potential in the pipe.

EBPC's Proposed Standard Design or Mitigation Measures:

* Design and construct Project to meet requirements of CSA Z662, CSA-C22.3 No. 6 Principles and Practices of Electrical Coordination between Pipelines and Electric Supply Lines.

EBPC's ESEA and Environmental Manual for Construction specify further details on standard mitigation.

Views of the Board

The Board finds that for this Project, if EBPC follows the above mentioned standard design or mitigative measures, these potential adverse environmental effects are not likely to be significant. Further, should the recommendations in section 9.2 be included as conditions of approval in any Certificate that the NEB may issue, implementation of the design and mitigation measures would be assured.

7.2.4 Detailed Analysis of Potential Adverse Environmental Effects

The discussion in these sections includes a summary of mitigation measures committed to by EBPC. The Board expects that detailed mitigation measures would be provided by EBPC in its EPP and other documents as part of its Environmental Management Framework as discussed in section 7.2.1.

7.2.4.1 Loss of Species at Risk or Species of Conservation Concern/Loss of Critical Habitat for these Species

Background/Issues

Based on existing surveys for the SJL and additional surveys carried out for the Project, the Applicant identified several Species at Risk or Species of Conservation Concern with the potential to inhabit areas on or near the project corridor, as noted in section 4.1.

EC recommended that baseline information on Species at Risk and Species of Conservation Concern, which may be impacted by the Project, be provided and that appropriate mitigation and monitoring measures be identified.

EBPC completed additional surveys in 2005 and 2006, the results of which were submitted to the Board, EC and NBDOE on 15 January 2007. The additional surveys examined fish and fish habitat, rare plants, wetlands, and birds, and visual observations were noted of wildlife Species of Conservation Concern during the biological fieldwork. EBPC's analysis indicated that no new results warranted additional mitigation above that already set out in its application.

Any species of concern that were identified during these surveys and any additional mitigation for Species at Risk or Species of Conservation Concern would be included in the EPP. EBPC indicated that it would consult with regulatory agencies, including EC, in

2007 following the submission of the survey results with respect to any specific issues and mitigation to be developed.

As part of its evidence, FORP submitted the results of surveys for rare aquatic vascular plants in Rockwood Park, data from the Atlantic Canada Conservation Data Centre about occurrences of rare and endangered fauna and flora in or near the preferred corridor in the City of Saint John, and a report on damselflies and dragonflies in Rockwood Park.

Mitigation Measures

EBPC committed to the following:

* Avoiding environmentally sensitive areas and Species at Risk and Species of Conservation Concern by route selection
* Limiting areas of disturbance
* Developing site-specific EPP measures to protect Species at Risk and Species of

Conservation Concern

* Including vascular plant Species at Risk and Species of Conservation Concern in employee awareness training
* Flagging or fencing environmentally sensitive areas prior to commencement of construction (including clearing)

* Field identifying and flagging critical Atlantic salmon spawning and rearing habitat in watercourse 109 (Dennis Stream) with Atlantic Salmon Federation personnel
* Avoiding critical Atlantic salmon spawning and rearing habitat in watercourse 11 (Dennis Stream) in consultation with DFO
* For isolated watercourse crossings, isolating work area and ensuring no wood turtles present before commencing work
* Checking open trenches for wildlife, such as wood turtles, prior to backfilling
* Conducting majority of clearing and site preparation work in winter months
* Confining clearing and grubbing to 30 m-wide RoW
* Minimizing footprint of temporary workspaces within forested areas
* Minimizing grubbing and grading within 30 m of all streams
* Establishing new RoW adjacent to existing linear developments and areas of disturbance (approximately 66% of preferred corridor includes existing RoWs)
* Working with appropriate regulating agency to develop any additional mitigation measures based on fish and fish habitat surveys, vegetation surveys and bird surveys conducted late 2006, and including these measures in the EPP
* Working with EC and provincial representatives to develop any mitigation measures for any Species at Risk identified during construction

Monitoring

EBPC committed to the following:

* Inspections of open pipeline trenches to ensure that no wildlife (particularly herpetiles) become trapped or buried in the trenches
* To address the potential for sedimentation to affect fish species, surface water compliance monitoring would consist of the following core elements for all wet-crossings, HDDs, dry-crossings rated as having medium or high sensitivity fish habitat (as outlined in applicable permits), and as determined in consultation with provincial and federal agencies:
* Sampling of total suspended solids when precipitation events result in the visible overland flow of water;
* Regular sampling of pH in watercourses where interaction with sulphide-bearing rock has been identified;
* Inspection of all sediment and erosion control measures;
* Inspection of hazardous materials storage areas (including potential sediment generating materials);
* Inspection of temporary bridge structures for verification of correct installation, and for subsequent signs of erosion or degradation;
* Development and maintenance of a log of erosion-prone areas; and

* Exceedance thresholds (e.g., CCME Guidelines) and remedial actions.
* Monitoring at meter stations and other station facilities for the potential environmental effects of herbicide use to vascular plant Species at Risk or Species of Conservation Concern

Follow-up Programs

EBPC has committed to developing a follow-up program to assess the effectiveness of proposed mitigation for fish and fish habitat with the following objectives:

* verify that mitigative strategies used during construction, operation and maintenance have been effective;
* determine the total amount of HADD that occurred as a result of the Project;
* verify that HADD compensation is completed effectively; and
* identify the need for any additional HADD compensation.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Low	2	Reversible	2	Low

Adverse Effect
Not likely to be significant

Views of the Board

The Board notes that EBPC has committed to including project-specific mitigation measures for fish, wildlife (including birds), and vegetation Species at Risk and Species of Conservation Concern, as identified in the 2006 surveys, in the EPP. The Board expects EBPC to develop mitigation in consultation with the appropriate regulatory agencies, specifically EC, DFO and provincial departments as appropriate.

If the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed:

* as part of the recommendation to submit an EPP outlined in section 7.2.1 above, the EPP shall address site-specific plans for habitat

harboring Species at Risk and of Conservation Concern where it cannot be avoided; and

* EBPC shall file with the Board for approval, at least sixty days prior to construction, follow-up programs as required by the CEA Act. A program shall be designed to verify the accuracy of the EA predictions and to assess the effectiveness of mitigation for fish and fish habitat as outlined in the Brunswick Pipeline Project ESEA (Volume 1). Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The follow-up program shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up program shall be filed with the Board based on that schedule.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations B (3), C and P.

Given the proposed mitigation measures, including avoiding environmentally sensitive areas, Species at Risk and Species of Conservation Concern by route selection within the corridor, EBPC's commitment to work with appropriate regulatory agencies in developing additional specific mitigation and to include additional specific mitigation in its EPP, and the above recommendations of the Board, the Board concludes that the Project is not likely to result in significant adverse effects to Species at Risk or Species of Conservation Concern.

7.2.4.2 Unauthorized Access to RoW

Background/Issues

Unauthorized access by ATVs was identified by EBPC as a potential interaction as a result of the Project. Potential adverse environmental effects include: change in quality of surface water, wetlands, fish habitat, vegetation habitat and wildlife habitat and direct mortality of fish, vegetation and wildlife. EBPC noted that human disturbance by ATVs was an environmental effect noted through monitoring studies of wetlands carried out on the SJL.

Unauthorized access to the RoW was raised as a concern in several comments from the public. Various parties voiced concern over the impact ATV access may have to wetlands, vegetation, water resources, fish and fish habitat, and wildlife and wildlife habitat along the pipeline RoW.

EBPC objected to a possible Certificate condition, circulated by the Board in advance of the oral portion of the hearing, which would require EBPC to file an Access Management Plan should the Project receive regulatory approval. EBPC argued that it has committed to address the issue of unauthorized ATV RoW access, reassess the effectiveness of the initial response, and refine its approach on an as-needed basis. Based on these commitments and in light of other anticipated Certificate conditions that would compel EBPC to implement these commitments, EBPC argued that the Access Management condition would be duplicative and unnecessary.

Mitigation Measures

EBPC indicated that measures to control access typically employed include installation of natural barriers using the natural topography to advantage (e.g., placement of rock barriers, planting of tree and shrub barriers), fencing and posting of signs prohibiting trespass. EBPC committed to developing specific measures to mitigate unauthorized access to the RoW after the detailed pipeline route has been selected and after discussions with landowners, stakeholders and regulatory agencies. EBPC also indicated that its Public Awareness Program would include a discussion of trespass and the potential consequences of unauthorized or unlawful entry onto properties along the RoW.

EC recommended that EBPC prepare a plan to prevent, monitor, report and remediate damage from ATV access to wetlands that reflects lessons learned from the SJL experience. Such a plan should also include the following elements:

* site-specific measures to prevent ATV use in wetlands along the RoW;
* provisions for ensuring that revegetated areas around wetlands damaged by ATV use are routinely monitored and restored as appropriate; and
* identification of the long-term threats posed by unauthorized access to the RoW, taking into account that once ATV trails have been established, access could continue post-decommissioning.

EBPC acknowledged that the main lesson learned from the experience to date, such as with the SJL, is that one type of control measure does not fit all scenarios. These measures must be tailored to the site conditions, landowner preferences, and the severity of undesired ATV traffic. Site-specific measures to address ATV traffic would be noted in the EPP.

Monitoring

EBPC committed to routinely monitoring the pipeline RoW for unauthorized activities during the course of the project operation and maintenance phase. If unauthorized activities in the RoW were detected, additional measures to stop or discourage unauthorized activities would be implemented after discussions with landowners, stakeholders and regulatory agencies, as appropriate.

EC indicated that it was unclear whether information collected through the monitoring program would be collected at regular intervals and provided to the appropriate federal and provincial government authorities for review.

Follow-up Programs

EBPC did not commit to developing a follow-up program specifically for access management.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
High	5	Reversible	1	Low

Adverse Effect
Not likely to be significant

Views of the Board

If the Project were to receive regulatory approval, to ensure that EBPC designs an effective Access Management Plan that would be implemented, monitored and reported on, the Board recommends that the following conditions be imposed:

* EBPC file with the Board for approval, at least thirty days prior to the planned start of construction, a project-specific Access Management Plan that includes:

a. EBPC's goals and measurable objectives regarding the Access

Management Plan;

b. the methods and procedures to be used to achieve the mitigation goals;
c. the criteria to determine if the mitigation goals have been met;
d. the frequency of monitoring activities along the right of way;
e. a description of the adaptive measures that would take place in the event that access management measures are ineffective; and

f. evidence of consultation with relevant regulatory authorities and landowners that either confirms satisfaction with the proposed mitigation or summarizes any unresolved issues with the proposed mitigation.

Construction shall not commence until EBPC has received approval of its Access Management Plan from the Board.

* EBPC file with the Board for approval, at least sixty days prior to construction, follow-up programs as required by the CEA Act. A program shall be designed to verify the accuracy of the EA predictions and to assess the effectiveness of mitigation for access management as outlined in the Access Management Plan. Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The follow-up program shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up program shall be filed with the Board based on that schedule. Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations C, G and P. For the purpose of clarity, the term "construction" as used in the Board's recommendations, and throughout this document, includes all clearing activities.

Although EBPC provided a comment that the first recommendation would be duplicative based on commitments already made by EBPC, unauthorized ATV access to the RoW resulted in adverse effects on the SJL and is cause for concern for several parties. The Board is of the view that the elements of the recommended condition set out specific requirements for information to be filed that are more explicit than that previously committed to by EBPC. It is up to EBPC to determine how it meets the condition and how it structures the Access Management Plan within or separate from other documents, such as its EPP. The Board has removed one requirement under the first recommendation from the version circulated for comment related to a schedule of expected reporting to the Board on the progress and success of the measures implemented. This requirement would be duplicative of the requirements in the second recommendation.

The Board notes EC's concern about whether information collected as part of EBPC's monitoring program would be regularly collected and filed with appropriate government authorities. As part of the second recommendation, the Board expects that EBPC would consult with relevant authorities on the development of the follow-up program and would develop a schedule for such filing of results in the follow-up program design.

Given the proposed mitigation measures and the above recommendations of the Board, the Board finds that the Project is not likely to result in significant adverse effects as a result of unauthorized access to the RoW.

7.2.4.3 Acid Rock Drainage

Background/Issues

EBPC acknowledged that Acid Rock Drainage (ARD) is an issue with potential impacts on water resources and aquatic life. Exposure of sulphide-bearing rock as a result of construction activities can result in acid drainage that can degrade water quality of down-gradient water. Approximately 64% of the urban portion of the corridor and approximately 67% of the rural portion of the corridor passes through potential sulphide-bearing rock.

EBPC submitted an ARD Management Plan, included as Appendix D of the Duke Energy Gas Transmission Manual for Construction Projects, that sets out mitigation measures to control ARD. EBPC would carry out a detailed drilling and sampling program to delineate the potential acid rock generating formations along the corridor.

NRCan submitted comments and recommendations regarding ARD. EBPC responded to all of these comments and recommendations. EBPC agreed that the best strategy is to avoid disturbing highly reactive rocks and committed to considering this approach where appropriate. EBPC committed to correcting errors and inconsistencies in the ARD Management Plan and resubmitting it to NRCan and other regulatory authorities.

EC recommended that a project-specific ARD Management Plan be developed including the following:

* the results of geophysical work and sampling, and identification of specific areas containing sulphide-bearing rock presenting an ARD risk;
* a description of options for disposing sulphide-bearing rock off-site if necessary

(e.g., scenarios involving significant quantities of rock); and

* a water quality monitoring program that describes sampling sites, outlines requirements for the collection of baseline and effects data (e.g., timing, parameters, frequency), and provides for a review of monitoring needs after one year of post-construction sampling and analysis.

In response, EBPC indicated that the results of geophysical investigation would be presented to regulatory authorities as appropriate. EBPC provided discussion of options for disposal of sulphide-bearing rock off-site. EBPC indicated that groundwater and surface water quality monitoring was set out in its ESEA.

EC also recommended that a post-construction review of plan effectiveness be conducted and the results reported. EBPC agreed to this recommendation.

Health Canada made a recommendation regarding specific parameters to be analysed as part of groundwater monitoring. EBPC agreed with this recommendation.

EBPC committed to:

* completing and submitting detailed geotechnical studies and related sampling to determine the areas of ARD potential to the Board, NRCan and any other appropriate regulating agency;
* submitting an updated version of their ARD Management Plan, based on NRCan's comments, to NRCan and the Board; and,
* undertaking a post-construction review of the ARD Management Plan and providing results to regulatory agencies.

Mitigation Measures

EBPC committed to the following:

* Conducting a drilling and sampling program with emphasis on bedrock areas near domestic water wells and in designated Watershed Protection Areas that present an acidic drainage risk
* Taking an inventory of water wells within 500 m and down-gradient of the acidic drainage risk zones
* Collecting baseline water samples for pH, aluminum (Al), iron (Fe), manganese (Mn), arsenic (As), copper (Cu), zinc (Zn), alkalinity, and sulphate for wells within 100 m of excavation zones in acid-generating bedrock and for watercourses in designated Watershed Protection Areas where the detailed RoW is within 250 m of a watercourse in acid-generating bedrock
* Carrying out excavation work and disposing of waste rock materials in accordance with appropriate regulatory guidelines, such as the *Nova Scotia Sulphide Bearing Material Disposal Regulations*
* Minimizing over-break of bedrock during excavation blasting
* Minimizing the extent of excavations in acid-generating bedrock areas
* Diverting surface water and shallow groundwater away from excavation in acid-generating bedrock areas

* Minimizing the volume of sulphide-bearing material requiring storage or disposal (e.g., by minimizing excavation, using excavated materials as backfill with capping where possible, and adjusting trench blasting activities to minimize over-breakage)
* Isolating the mineralized portion of the trench with impermeable fills
* Minimizing groundwater through flow along trenches using impermeable plugs or barriers
* Remediating any affected wells by deepening the well, using grouted casing or liners, or replacing the well and
* Engaging a qualified professional to conduct an initial screening for evidence of acidic drainage (drop in pH or visual evidence of iron precipitate) within seven days of the implementation of acid rock mitigation

Additional details regarding ARD about mitigation measures to be used were provided by EBPC in its ARD Management Plan.

Monitoring

EBPC committed to the following:

* Pre-construction monitoring of all water wells identified within 500 m and down-gradient of the acidic drainage risk areas would be located and documented on appropriate maps.
* Pre-construction monitoring of all water wells within 100 m of Project RoW (when determined) and down-gradient of bedrock excavation zones in acidic drainage risk areas would have baseline water samples collected for pH, Al, Fe, Mn, As, Cu, Zn, alkalinity, and sulphate.
* Post-construction monitoring within ARD areas that coincide with residential wells along the preferred corridor, the nearest down-gradient residential well within 500 m of the RoW would be used as a monitoring well. This well would be checked on a quarterly basis for two years for general chemistry in order to identify any changes in groundwater quality that might be indicative of acidic drainage.
* Post-construction monitoring in areas where bedrock with ARD potential were exposed within 250 m of a watercourse within a designated Watershed Protection Area, quarterly monitoring for ARD indicator parameters would be done for two years for general chemistry in order to identify any changes in stream water quality that might be indicative of acidic drainage.

NEB Evaluation of Significance

Geographical

Frequency	Duration	Reversibility	Extent	Magnitude
High	3	Reversible	1	Low

Adverse Effect
Not likely to be significant

Views of the Board

As a result of the concern from interested parties, RAs and FAs about the potential for acid rock drainage and its effects, if the Project were to receive regulatory approval, the Board recommends that the following condition be imposed:

* As part of the recommendation to submit an EPP outlined in section 7.2.1 above, the EPP shall address project-specific acid rock drainage mitigation measures.

Therefore, the Board has included a recommendation to this effect in section 9.2 as recommendation B(4).

The Board expects that the measures set out in the EPP to address ARD would be included in EBPC's revised ARD Management Plan, and that this Plan would be provided to NRCan, EC and other regulatory authorities being consulted on the EPP. The Board also notes that a post-construction review of the ARD Management Plan's effectiveness would be conducted and submitted to the appropriate regulatory agencies.

Given the proposed mitigation measures and the above recommendations of the Board, the Board finds that the Project is not likely to result in significant adverse effects as a result of ARD.

7.2.4.4 Loss of Wetland Function

Background/Issues

Eighty wetlands were identified during desk-top studies and field studies as occurring within the preferred corridor with approximately 800 ha of total area occupied by wetland habitat.

EBPC submitted that studies conducted for the NB Power IPL and for the SJL contain sufficient biophysical information for the purposes of completing wetland functional analysis reports. EBPC completed additional wetland surveys in 2005 and 2006, the results of which were submitted to the Board, EC and NBDOE on 15 January 2007. These additional surveys provided the remainder of the information required to complete wetland functional analysis reports.

Wetland function may be lost during various construction activities: site preparation, pipe installation, watercourse crossings and temporary ancillary structures and facilities. EC and NBDOE have set goals for no net loss of wetland function.

Mitigation Measures

EBPC committed to the following:

* Avoidance of wetlands by route selection, wherever practicable
* Limiting area of disturbance
* Developing a crossing and rehabilitation plan for wetlands, to be included in the EPP, that assesses alternative construction methods to minimize impacts to wetlands to protect wetland function
* Obtaining WAWA permits and following permit conditions, including compensation to ensure no net loss of wetland function
* Obtaining approval to blast from DFO and following DFO's blasting guidelines
* Maintaining water flow and drainage within or across wetland
* Using designated roadways and access; limit off-road activity
* Avoiding locating temporary work areas in wetland, where practicable
* Stockpiling surface wetland soils separately and then return them to wetland
* Avoiding seeding in and within 30 m of wetland
* Using cleaning stations for equipment and vehicles where required to reduce the spread and introduction of invasive species of plants
* Avoiding directing runoff water flow toward wetland
* Using erosion control measures
* Storing fuel at least 100 m from wetlands
* Refueling at least 30 m from wetlands
* Installing trench plugs in open trench to avoid water flow along the trench
* Restricting herbicide use during pipeline operation to fenced area of valve sites and using herbicide of short persistence and low ecological toxicity
* Using measures to address unauthorized access to the RoW by off-road vehicles (discussed in Table 7.2.4.2)

Monitoring and Follow-up Programs

EBPC committed to developing a follow-up and monitoring program for wetlands in consultation with regulatory authorities. EBPC recommended wetlands post-construction monitoring (typically at one, three, and five years after construction) to assess issues such as wetland hydrology, introduction of invasive plant species and use by ATVs. Beyond the wetland monitoring, operations and maintenance personnel would monitor the entire length of the pipeline system (including wetlands) to identify any issues. Details of monitoring and surveillance during operations and maintenance would be included in the Operations and Maintenance Manual. EC recommended that:

* a monitoring, mitigation and maintenance program associated with construction activities in wetland areas be undertaken, and that monitoring and maintenance continue as necessary until wetland functions are restored to a pre-construction state; and
* a plan for compensating for unavoidable loss of wetlands be prepared taking into account federal and provincial wetland conservation policies, as applicable.

EBPC committed to meeting with EC and provincial representatives to discuss information gathered on wetlands. It also committed to discussing compensation for loss of wetland function with EC and the Province after the proposed five-year monitoring period.

In its final argument, EC reiterated that wetland monitoring should continue until wetland functions are restored, as opposed to the five-year limit proposed by EBPC. EC also reiterated that a plan for compensating for unavoidable loss of wetlands be prepared, and was not satisfied with EBPC's commitment to only address losses identified following completion of a five-year monitoring program.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Low	1	Reversible	1	Low

Adverse Effect
Not likely to be significant

Views of the Board

If the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed.

* As part of the recommendation to submit an EPP outlined in section

7.2.1 above, the EPP shall address site-specific construction plans for wetlands where they cannot be avoided; and

* EBPC file with the Board for approval, at least sixty days prior to construction, follow-up programs as required by the CEA Act. A program shall be designed to verify the accuracy of the EA predictions and to assess the effectiveness of mitigation for wetlands as outlined in the Brunswick Pipeline Project ESEA (Volume 1, p. 350). Copies of

all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The follow-up program shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up program shall be filed with the Board based on that schedule.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations B (2), C and P.

In developing site-specific plans for wetlands in its EPP and in designing the follow-up program for wetlands, the Board expects that EBPC would consult with EC and NBDOE. It would be appropriate that the follow-up program schedule and associated reporting schedule be designed to address any effects that may endure beyond EBPC's proposed five-year monitoring period. The follow-up program should also set out a process for establishing compensation for unavoidable loss of wetlands identified during the implementation of the follow-up program.

Given the proposed mitigation measures and the above recommendations of the Board, the Board concludes that the Project is not likely to result in significant adverse effects to wetlands.

7.2.4.5 Biophysical Effects to Rockwood Park

Background/Issues

Biophysical effects in Rockwood Park would be similar to the biophysical effects throughout the RoW previously addressed in Table 7.2.3. However, concerns were raised by many interested people around effects specific to Rockwood Park. Among the comments received from the public, concerns were expressed regarding industrial development occurring in land designated for use as a park and potential effects in Rockwood Park on surface water, wildlife and caves.

FORP, as part of its evidence submitted to the Board, filed the following studies or reports:

* Rare aquatic vascular plants of Rockwood Park;
* Odonata of Rockwood Park;
* Atlantic Canada CDC Data Response - rare flora and fauna in study area;
* Geological Considerations vis-à-vis the proposed siting of a natural gas pipeline through Rockwood Park; and
* Status and Conservation of Dissolution Caves in Rockwood Park.

In response to FORP's evidence, EBPC indicated that it consulted with the Horticultural Society and the City, which together have responsibility for the Park. Consultation resulted in the proposal of specialized construction plans and improvements within the Park that would enhance public access and enjoyment in the future. EBPC also indicated that it is prepared to endow the Park with a grant to fund Park improvements and future Park operations should the preferred corridor be approved.

Mitigation Measures

EBPC committed to the following:

* Mitigation measures for minimizing environmental effects on bio-physical elements consistent throughout the Project (refer to Tables 7.2.3, 7.2.4.1-7.2.4.4)
* Developing a specialized construction plan for the Park

Monitoring

EBPC committed to the following:

* Monitoring as described in section 7.1 and Tables 7.2.4.1 through 7.2.4.4
* Additional monitoring would be addressed in the EPP

Follow-up Programs

EBPC did not propose a follow-up program specific to Rockwood Park.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude

Medium	2	Reversible	2	Low

Adverse Effect
Not likely to be significant

Views of the Board

In light of the concerns raised with respect to Rockwood Park, if the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed:

* as part of the recommendation to submit an EPP outlined in section 7.2.1 above, the EPP shall address a construction and reclamation plan for Rockwood Park with evidence demonstrating consultation with stakeholders; and
* EBPC shall file with the Board for approval, at least sixty days prior to construction, follow-up programs as required by the CEA Act. A program shall be designed to verify the accuracy of the environmental assessment predictions and to assess the effectiveness of mitigation used for the reclamation of Rockwood Park. Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The follow-up program shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up program shall be filed with the Board based on that schedule.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations B (5), C and P.

Given the proposed mitigation measures and the above recommendations of the Board, the Board finds that the Project is not likely to result in significant adverse effects as a result of biophysical effects to Rockwood Park.

7.2.4.6 Disruption to Recreational Pursuits in Rockwood Park

Background/Issues

Rockwood Park is a popular destination for Saint John residents and visitors. In various seasons, Rockwood Park offers the following attractions: Kiwanis Playpark at Fisher Lakes; Rockwood Park Municipal Golf Course & Aquatic Driving Range; Rockwood Park Campground; Cherry Brook Zoo & Vanished Kingdom Park; beaches at Fisher Lakes and Lily

Lake; hiking, biking, cross-country skiing, and running trails; picnic sites at Fisher Lakes and throughout the wilderness zone of the Park; Rockwood Stables & Turn of the Century Trolleys; and horseback riding.

Mitigation Measures

EBPC committed to developing a specialized construction plan for Rockwood Park in collaboration with the stewards of the Park and other stakeholders.

During construction, trails that cross the RoW may be temporarily disrupted during pipe installation but the existing topography and surface would be restored to the extent practicable, and other mitigation measures would be implemented in consultation with the Saint John Horticultural Society, the City of Saint John (Leisure Services), and other stakeholders.

Certain activities within or near the proposed pipeline RoW (e.g., campfires, excavations, installation of fence posts) would require that the Proponent be notified in advance of the activity, in accordance with the OPR, to ensure that the activity does not compromise the integrity of the pipeline.

There would be no above-ground obstructions or features in the RoW that would limit access to any of the Park's trails or facilities.

The existing topography of the land within the Park adjacent to the power transmission line RoW would be restored to the maximum extent practicable.

Views of the parties

Numerous Intervenors, oral statement makers, and letters of comment raised serious concerns regarding the disruption to recreational pursuits in Rockwood Park including, for example: industrial development not enhancing a nature sanctuary, horse riding trails being negatively impacted by the pipeline, and use of trails with blasting, bulldozers and heavy equipment all around.

Views of EBPC

According to EBPC, activities that currently occur in the Park would not be altered after construction, and all recreational activities that currently occur in Rockwood Park, in any season, would be allowed to continue during the operation and maintenance phase of the Project.

EBPC stated that it is prepared to endow Rockwood Park with a grant to fund Park improvements and future Park operations, should the preferred corridor be accepted and the pipeline built.

EBPC argued that the environmental studies and mitigation regarding the protection of the environment, as well as the protection of members of the public using Rockwood Park, further the preservation of the current activities within Rockwood Park. As well, participation of the Park stakeholders regarding the restoration of the proposed RoW in Rockwood Park may serve to enhance the current activities taking place within the Park.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Low	2	Reversible	1	Low

Adverse Effect
Not likely to be significant

Views of the Board

The Board notes that some recreational pursuits in Rockwood Park would be temporarily disrupted during construction activities. These short-term disruptions would be minimized with the development, in collaboration with the stewards of the Park, of a specialized construction plan for Rockwood Park. The Board also notes that there would be minimal impacts on recreational pursuits during the operations phase of the pipeline, and it is even possible that there would be enhancements with the creation of a trust fund to provide an annual income for the Horticultural Society. Given the proposed mitigation measures, in particular the specialized construction plan for Rockwood Park, and the commitment by EBPC to establish a trust fund for the Horticultural Society, the Board finds that the proposed Project would not likely cause significant adverse effects to recreational pursuits in Rockwood Park.

7.2.4.7 Disturbance to, or Destruction of, Heritage Resources

Background/Issues

The Archaeological Services Unit (ASU) of the Heritage Branch of the NB Culture and Sports Secretariat administers archaeological resources in

NB. Archaeological sites are considered to be non-renewable resources and the unauthorized disturbance of such resources may not legally take place except under strictly controlled conditions imposed by the terms of an Archaeological Field Research License, which is issued to qualified personnel by the provincial government through ASU. ASU is also responsible for approving or modifying recommended mitigation measures applied to archaeological and heritage resources.

The archaeological survey work outlined in the ESEA is underway. One archaeological site has been recorded to date and the mitigation of that site has been initiated, in consultation with the ASU. This site, at Dennis Stream, has been visited by members of the MAWIW Environmental Response Team, who actively participated in the excavations. Further, reports of a Native burial ground at Point Pleasant were noted and this area was identified for archaeological testing. Testing is ongoing and results will be reported to the UNBI, MAWIW, the NEB and ASU. To date, no evidence of any burials has been encountered.

The archaeology surveys are ongoing and will be completed this year or in the spring of 2007. It is anticipated that the results of these surveys will be submitted to the NEB and ASU prior to April 2007. Archaeological work undertaken in the spring of 2007 will be reported as it is completed.

Mitigation Measures

EBPC committed to the following:

* The entire length of the detailed route would be subject to a walk-over and survey once the 30 m RoW is determined. Archaeological testing would also be conducted in areas where it is considered warranted. Where there are limitations in flexibility for watercourse crossing locations, each option would be tested prior to confirming the route. This methodology has been discussed and developed in conjunction with ASU, and is approved by the Province. This methodological approach would ensure that the majority of archaeological and heritage resources within the detailed route would be identified, recorded and mitigated prior to construction.
* If a significant archaeological or heritage resource were encountered within the RoW during the pre-construction survey, then appropriate mitigation would be developed in consultation with the provincial regulating agency (ASU) and implemented.
* Adjustment of the RoW would be considered as the preferred mitigation to avoid significant archaeological sites discovered during the detailed route.
* If avoidance of the resource is not practicable, then the archaeological or heritage site would be mitigated by recording, testing, and

excavation, as determined by the archaeologist and in consultation with ASU.

* Provide opportunity for access to exposed rock to paleontologists.
* Areas where there are known archaeological or heritage resources located near to, but not within the boundaries of, the RoW would be demarcated and/or fenced, and the construction in the adjacent areas may require monitoring.
* EBPC would develop a set of archaeological protocols in the EPP to address any encounters with archaeological/heritage resources during construction, and would implement this protocol.

Monitoring

EBPC indicated that areas that still considered to have elevated potential for archaeological or heritage resources would be recommended for archaeological monitoring during the construction phase of the Project.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Low	1	Irreversible	1	Low

Adverse Effect
Not likely to be significant

Views of the Board

If the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed:

* EBPC shall consult with the ASU of NB on further studies and a monitoring plan for areas with high potential for heritage resources, once the locations for the detailed right of way, facility sites and temporary work space have been determined. EBPC shall file with the Board, at least thirty days prior to construction:

a. for approval, a report that documents how archaeological and heritage resources within the detailed route have been identified, recorded and mitigated;

b. copies of any correspondence from, or a summary of any discussions with the ASU of NB regarding the acceptability of EBPC's report and proposed mitigation measures; and

c. for approval, a copy of any proposed monitoring plan.

* EBPC shall notify the Board, at the time of discovery, of any archaeological or heritage resources and, as soon as reasonable thereafter, file with the Board for approval a report on the occurrence and proposed treatment of the archaeological/heritage resources, any changes to the archaeological/heritage monitoring plan, and the results of any consultation, including a discussion on any unresolved issues.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations F and J.

Given the proposed mitigation measures, the commitment by EBPC to complete archaeology surveys, the commitment by EBPC to consult with the ASU prior to construction on further studies and a monitoring plan for areas with high potential for heritage resources, and the above recommendations, the Board finds that the Project would not likely cause significant adverse effects on heritage resources.

7.2.4.8 Noise Impacts at Milford and Pokiok

Background/Issues

The major watercourse crossing of the Saint John River in urban Saint John would require HDD, which has the potential to cause an adverse environmental effect on sound quality. An HDD is planned to cross the Saint John River from Pokiok to Pleasant Point in the City of Saint John.

The Saint John River HDD would occur 24 hours per day for approximately 20 weeks, during which relatively high sound pressure levels may be experienced on a more or less continuous basis. The typical equipment required consists of a drilling rig, electric mud pumps, portable generators, mud mixing and cleaning equipment, mobile cranes, forklifts, loaders, trucks, and portable light sets.

Mitigation Measures

EBPC committed to undertake a detailed noise mitigation study and develop detailed noise mitigation and monitoring plans specific to the areas potentially affected by the HDD activity, and would submit these plans to the NEB and Health Canada at least 90 days prior to the commencement of the proposed HDD activities. Additional mitigation measures to reduce the environmental effect of the Saint John River HDD activities on sound quality include:

* Further predictions would be conducted (based on the mitigation design) of drilling sound levels at the nearest residences prior to the commencement of HDD at the site.
* The drilling rig at the Saint John River site would be partially or fully enclosed as required, and/or noise barriers would be placed around the drilling site with adequate mass, height and length to attenuate noise to below 65 dBA at the nearest receptor. The enclosures would be set up with the required opening directed away from the nearest residences so that line of sight propagation of noise would occur away from the nearest residences.
* The arrangement of the drilling rig and other equipment, which are major sources of noise, would be designed to maximize the distance between this equipment and the nearest residences.
* All construction equipment used in the area would be maintained in good working condition according to the manufacturer's instructions. Mufflers that are in good working condition or upgraded silencers (if warranted) would be used.
* The use and movement of ancillary equipment would be minimized during nighttime hours.
* A noise mitigation design would be developed following the completion of the drill site layout and estimates of sound pressure levels (based on the mitigation design) at nearby noise sensitive areas to ensure adequate mitigation is in place prior to commencing HDD activities at the Saint John River site.
* A program would be in place for members of the public to contact representatives of the company and express any concerns about noise, and EBPC committed to addressing those concerns. EBPC indicated that temporary relocation would only be offered as a means of mitigation as a last resort.

Monitoring

EBPC indicated that following the installation of HDD equipment and noise control measures, follow-up noise monitoring would be conducted at the nearest residences to verify the effectiveness of the mitigation. Further mitigation would be implemented in the event of unacceptable noise levels and additional monitoring would be conducted to ensure acceptable noise levels prior to the commencement of 24-hour drilling.

Additional noise monitoring or mitigation may be required to address any potential complaints from residents received by the NEB, NBDOE, or EBPC, particularly during construction activities. Noise monitoring would be required to verify the effectiveness of the noise mitigation for the HDD activities. Sound pressure levels would be monitored during HDD activities, during daytime hours at the nearest residence prior to the continuation of HDD activities on a 24-hour basis.

In addition, spot checks of noise levels would be conducted by EBPC at the nearest residences on a periodic basis during HDD activities, to monitor the effectiveness of the implemented mitigation and to provide a basis for implementing further actions aimed at preventing significant environmental effects during construction.

Follow-up Programs

EBPC committed to developing a follow-up program to assess the effectiveness of proposed mitigation for HDD Noise Management.

Views of the parties

Several Intervenors, oral statement makers, and letters of comment raised concerns regarding the disruption to residents of Milford and Pokiok; for example, parties disagreed that short-term noise impacts associated with the directional drill, specifically 24/7 for a 4 month period, would constitute a short period.

HC raised concerns regarding noise associated with HDD activities. In a letter dated November 3, 2006, HC identified six conditions that must be met by EBPC in order for HC to be satisfied that the proposed mitigation is adequate and all reasonable measures have been implemented in order to minimize the additional noise levels that would result from intruding construction noise from HDD activities. HC also provided comments on the possible Certificate conditions, and recommended that greater detail be provided in any Certificate condition regarding noise.

Views of EBPC

EBPC committed to developing a detailed noise mitigation plan for the Saint John River HDD activity in consultation with Health Canada and other appropriate regulatory authorities. The objective of the noise mitigation is to keep people living in proximity to the HDD comfortable.

EBPC's environmental consultants agreed that unmitigated noise from HDD activities at the Saint John River crossing could result in a significant adverse environmental effect to residents within 300 m (984 feet) of the crossing and possibly even beyond the 300 m radius. It is for this reason that extensive noise mitigation, based on sound pressure levels at the nearest residence to the crossing, was proposed in the ESEA and would be implemented throughout the duration of HDD activities. If mitigation were implemented such that sound pressure levels remained at a level that would not result in significant environmental effects to residents within 300 m of the noise source, EBPC expected that there would be no significant environmental effects to residents beyond the 300 m radius as sound due to a dominant source decreases with distance from the source.

EBPC consulted with HC regarding noise associated with the HDD activity and was in agreement with HC's comments and recommendations on this issue. EBPC stated that it was confident that its mitigation measures would ensure its operations do not conflict with the standards reflected in the applicable bylaws within the context of the construction of the Project. EBPC argued that the Board has extensive experience with HDD operations and, together with the input provided by HC, has established acceptable standards governing this activity. Comprehensive noise mitigation for the Saint John River HDD activity would be implemented as necessary to ensure no residual adverse environmental effects and to minimize disruption to daily living for residents of Milford and Pokiok.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Medium	2	Reversible	2	Medium

Adverse Effect
Not likely to be significant

Views of the Board

If the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed:

* EBPC shall file for approval, at least ninety days prior to the start of the HDD activity proposed for the Saint John River Crossing, a detailed noise management plan containing information on day-time and night-time HDD operations at the drill exit and entrance sites, including but not limited to the following:

a. ambient sound levels at noise-sensitive areas close to the HDD exit and entrance sites to establish a baseline for assessing potential noise impacts;
b. predicted noise level at the most affected residences caused by the HDD without mitigation;
c. proposed HDD noise mitigation measures, including but not limited to the following:

* all technologically and economically feasible mitigative measures as presented in Section 5.1.7 of the Environmental and Socio-Economic Assessment (Jacques Whitford, 2006) and in the Resource Systems Engineering assessment.
* the use of full enclosures on diesel powered units;
* the use of quiet machinery (where feasible);
* the undertaking of HDD activities during periods where residential windows would be expected to be closed (i.e., during winter months);

d. predicted noise level at the most affected residences with implementation of the mitigation measures;
e. noise contour map(s) showing the potentially affected residences at various noise levels;
f. a noise monitoring program including locations, methodology and schedule;
g. confirmation that residents potentially affected by HDD noise will receive contact information for EBPC in the event they have concerns about the HDD noise;
h. a contingency plan with proposed mitigative measures for addressing noise complaints, which may include the temporary relocation of specific residents; and
i. confirmation that EBPC will provide notice to nearby residents in the event that a planned blowdown is required and that planned blowdowns will be completed during day-time hours whenever possible.

* EBPC shall file with the Board for approval, at least sixty days prior to construction, follow-up programs as required by the CEA Act. A program shall be designed to verify the accuracy of the Environmental Assessment predictions and to assess the effectiveness of mitigation for HDD noise management. Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The follow-up program shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up program shall be filed with the Board based on that schedule. Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations C, H and P.

Given the proposed mitigation measures, the commitment by EBPC to develop a detailed noise mitigation plan for the Saint John River HDD site with input from HC and the NEB, the commitment by EBPC to develop a follow-up program, and the above recommendations, the Board finds that the proposed Project and associated noise at Milford and Pokiok would not likely cause significant adverse effects.

7.2.4.9 Effects on the Current Use of Lands and Resources for Traditional Purposes by Aboriginal Persons

Background/Issues

Throughout project development, there were consultations regarding the Brunswick Pipeline with all NB Aboriginal organizations and communities recognized by the Government of Canada. An Aboriginal Relations Manager and organization liaison staff facilitated the consultation, which included extensive direct meetings with the Aboriginal organizations and open houses for the Aboriginal communities.

To augment information gathered during the Aboriginal open houses regarding the traditional use of lands and resources within the preferred corridor, an Aboriginal firm, Aboriginal Resource Consultants, was contracted to carry out a TEK study. This study gathered Maliseet and Mi'kmaq historical knowledge of land, water and resource uses by Aboriginal people for traditional purposes in the project area. The TEK Study recommended continued site visits and continued communication of project information with Aboriginal leadership and community members.

Mitigation Measures

EBPC committed to the following:

* A copy of the TEK study was provided to the Maliseet and Mi'kmaq Peoples through their leadership. Further, an information dissemination strategy would be developed to ensure the leadership is kept informed on all developmental activities.
* A team of Aboriginal specialists would be engaged for a walk through of the RoW, once finalized in the summer of 2007, to "ground truth" any issues of concern and report on findings from this physical inspection to both the Proponent and the Aboriginal leadership.
* A strategy would be developed allowing for black ash harvested from Crown lands within the RoW to be stockpiled in an accessible location and made available to the Maliseet and Mi'kmaq.
* Response protocols would be developed to provide information exchange channels allowing for the reporting of any incidents of sites of significance to the Maliseet and Mi'kmaq.

Monitoring

EBPC was able to conclude formal agreements with both the UNBI and MAWIW. The agreements include provisions for environmental monitoring and protection of Aboriginal heritage and cultural resources.

During all construction phases where "green field" development is taking place, an Aboriginal monitor will be engaged, who has specific knowledge and experience related to traditional use and spiritual and ceremonial sites. This individual would be tasked with assisting and recommending to project personnel any findings during construction that may impact the Maliseet and Mi'kmaq people.

Views of the Parties

On 20 October 2006, the MAWIW Council of First Nations submitted a letter indicating that with the conclusion of twin agreements with M&NP and Emera, the MAWIW Council supported the Brunswick Pipeline application.

On 26 October 2006, UNBI filed a letter stating it is withdrawing as an Intervenor in the NEB hearings because it had reached a benefits agreement with EBPC.

An oral statement maker indicated that he was concerned that the Passamaquoddy had not been properly consulted since the pipeline falls in their territory, and that he read that the Passamaquoddy currently use plants harvested in and around the corridor for food and medicine.

Views of EBPC

EBPC stated that with respect to Aboriginal consultation, during early stages of Project planning, it engaged in consultations directed at securing Aboriginal support for and involvement in various project activities. Careful attention was paid to mitigating impacts upon traditional uses along the pipeline route and EBPC submitted that the process was open and inclusive. Consultations resulted in agreements with the Province's two Aboriginal organizations, both of whom indicated their support for the timely approval of the Project.

EBPC submitted that the conclusion in the Brunswick Pipeline ESEA, that there would not be any direct interaction between the Brunswick Pipeline Project and areas of traditional land and resource use that cannot be mitigated, was confirmed through the First Nation consultation program and the TEK Study. Therefore, EBPC anticipated that there would be no significant adverse environmental effects to current use of land and resources for traditional purposes by Aboriginal persons located in the area to be traversed by the pipeline.

This conclusion applied to all Aboriginal persons. While the Passamaquoddy Tribe is not a federally or provincially recognized organization, and therefore, were not included in the formal consultation process, EBPC submitted that should any of its members carry out traditional use activities in the preferred corridor, they would be similar uses, with similar resources, as the Mi'kmaq and Maliseet People of NB. There would not be significant adverse effects to current use of lands and resources for traditional purposes, if any, by members of the Passamaquoddy.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Low	2	Reversible	2	Low

Adverse Effect
Not likely to be significant

Views of the Board

If the Project were to receive regulatory approval, the Board recommends that the following condition be imposed:

* EBPC shall file with the Board, at least sixty days prior to construction, an update on the implementation of the six recommendations identified in the TEK Study (July 2006).

Therefore, the Board has included a recommendation to this effect in section 9.2 as recommendation D.

The Board notes the steps that EBPC has taken to secure support from the Mi'kmaq and Maliseet People of NB.

With respect to the Passamaquoddy First Nation, the Board notes EBPC's position that it is likely that any members of the Passamaquoddy Tribe carrying out traditional use activities in the preferred corridor would have similar uses, with similar resources, as the Mi'kmaq and Maliseet People. While consultation with potentially affected parties is an expectation for consultation programs, the Board notes that there was very limited evidence submitted during the proceeding that the Passamaquoddy Tribe would be impacted by the Project, or that it used the preferred corridor for any traditional use activities; only a brief mention of this topic was made during an individual's oral statement. Nor did the Passamaquoddy Tribe appear before the Board in any capacity. In any event, the Board concurs with EBPC's view that any current use of lands and resources for traditional purposes by the Passamaquoddy people would likely be similar to that identified for other Aboriginal persons.

The Board notes that the potential impacts of the proposed Project to vegetation, fish and fish habitat, wildlife and wildlife habitat, and wetlands are not likely to be significant, as determined in other sections of this EA Report. These findings would further mitigate any adverse effects on the current use of lands and resources for traditional purposes by Aboriginal persons. In addition, the ability for Aboriginal persons to use the lands and resources for any traditional purposes could be temporarily impacted by construction activities but would not likely be significantly impacted during the operations phase of the Project. As a final point on this topic, the Board recognizes EBPC's commitment to establishing a process through which any issues, including those that may be raised by the Passamaquoddy, could be communicated and considered by EBPC through its Aboriginal Manager.

Given the proposed mitigation measures and the above recommendation, the Board finds that the proposed Project would not likely cause significant adverse effects on the current use of lands and resources by Aboriginal people for traditional purposes.

7.2.4.10 Potential Pipeline Leak or Rupture, and Potential Associated Fire

EBPC noted the potential for accidents and malfunctions to occur during the operation and maintenance of the Project, and addressed the potential for pipeline ruptures or leaks. Many of the comments received from the public regarding this Project were concerns about consequences of a pipeline leak or rupture and potential associated fire, concerns about access to communities in the event of an emergency and the capacity of first responders to handle an emergency.

EBPC's Environmental Management Framework is described in section 7.2.1 above. Several of the components of this framework would be applicable to preventing and responding to a pipeline leak or rupture. As part of EBPC's Pipeline Design and Quality Assurance Program, the Pipeline would be designed in accordance with the CSA Z662 standard and quality assurance would be used to reduce the probability of material defects. EBPC's Environmental Protection and Safety Management Program would include a Pipeline Integrity Program and routine pipeline monitoring and surveillance.

EBPC submitted that its Emergency Preparedness and Response Program would address: emergency response training; the scope and frequency of emergency response exercises; continuing education programs for first responders and Emergency Planning Zone (EPZ) residents; and, a formal liaison program for both lead and supporting government agencies. In order to support this program, EBPC committed to conducting a risk assessment upon completion of the detailed routing to determine the size of the EPZ for the pipeline.

EBPC submitted that its Field Emergency Response Plan (ERP) would be comprehensive and would: identify arrangements made to respond to pipeline incidents, including any mutual aid agreements made with outside agencies; outline roles and responsibilities related to emergency response; define notification and reporting requirements for incidents; and provide guidelines and site-specific emergency response procedures for operation and maintenance staff and first responders. EBPC committed to developing its ERP in consultation with the following lead agencies early in 2007:

* Transportation Safety Board of Canada;
* National Energy Board;
* New Brunswick emergency management organizations (EMO);
* Saint John EMO;
* Provincial Fire Marshall;
* Provincial and Municipal 911 Agencies;
* RCMP;
* Saint John City Police and Fire Department;
* Rural fire departments and volunteer fire brigades; and
* Ambulance brigades.

EBPC also committed to filing the ERP with the NEB well in advance of obtaining final leave of the Board to operate the pipeline.

Further, EBPC committed to implementing a continuing education program for first responders (i.e., fire departments, police, emergency management organizations) that would include the assignment of roles and responsibilities and chain of command for emergencies along the pipeline route, conducting emergency response training and mock emergency exercises, and educating applicable emergency response agencies.

EBPC committed to implementing a public awareness and education program with the intent of alerting the public of the requirements and restrictions associated with activities conducted in and around the pipeline RoW.

In response to questions from the Board regarding the location of isolation valves, emergency response capability within each line segment and reliability of the isolation valves, EBPC submitted that the Brunswick Pipeline has been designed to Class III requirements throughout its entire length within the City of Saint John in order to offer the pipeline added protection.

EBPC indicated that valve site locations were chosen on the basis of proximity to commercial power and telephone service as well as being of sufficient size to allow for the installation of all necessary infrastructure. A further consideration in the location selected for each isolation valve was year-round access by company personnel. EBPC submitted that each location provides good year-round access for both normal maintenance and for emergency response.

EBPC indicated that line block valves would use a gas-over-hydraulic actuator for closure and that this type of actuator has proven to be highly reliable with a ready fuel source (natural gas pressure within the pipeline) for actuation.

The worst case incident associated with the proposed facilities, as described by EBPC, would be a full rupture of the operating pipeline and subsequent ignition of the venting natural gas. In the event of such an incident, EBPC indicated that the line block valves immediately upstream and downstream of the line break would be closed by EBPC personnel to isolate the damaged section of pipeline from the remainder of the pipeline system. The damaged section would vent rapidly and EBPC personnel and local first responders would then continue with the execution of their respective emergency response procedures.

In light of the preferred corridor being in proximity to schools, a hospital, various businesses, and various communities, many interested people raised concerns regarding EBPC's capability to respond to an emergency and gain access to their communities or other existing infrastructure.

In addressing these concerns, EBPC submitted that once an EPZ is determined, EBPC would work to develop an accurate database of occupied structures within the EPZ. Residents within the EPZ would be contacted through EBPCs Continuing Education Program. This program would provide information to residents within the EPZ on pipeline location, potential emergency situations, safety procedures, what to expect in the event of an emergency and the respective roles of the public, company personnel, first responders (such as fire departments), and EMOs.

In the event of a serious pipeline incident requiring evacuation, EBPC indicated that the evacuation itself would be led by first responders and EMOs, including the selection and coordination of sheltering locations, incident command centers, roadblocks, etc.

Milford area residents, in particular, raised concerns regarding emergency access to their community as the Lou Murphy overpass is the only access in and out of this area, and the pipeline corridor passes close to this overpass.

In addressing these concerns, EBPC indicated that public access to the Milford area would not be impeded in any way during the construction or operation of the Brunswick Pipeline.

Furthermore, EBPC indicated that it has been assured by J.D. Irving Limited that access would be provided across its lands for emergency response vehicles and personnel should the existing access (Greenhead Road) be impeded by a pipeline incident. EBPC confirmed that J.D. Irving Limited personnel and equipment are on site 24 hours a day and could quickly open the gates for emergency assess.

EBPC addressed concerns of Intervenors with respect to public notification in the event of an emergency and areas with limited access by committing to work with first responders and EMOs to adopt, promote, or help develop methods to notify the public and to identify areas with limited access and consider alternate routes. However, EBPC noted that primary responsibility in the event of a public emergency lies with first responders.

EBPC also noted that first responders have the ability to access property in emergencies in ways that would not normally be available to the public. The arrangement reflected in the letter with J.D. Irving, for example, ensures that should City of Saint John fire trucks, police cars or emergency vehicles appear at the J.D. Irving plant gate urgently seeking access to the Milford area, they would be able to readily access that community.

In response to possible Certificate conditions circulated for comment in advance of the oral portion of the hearing, EBPC provided comments to the Board on a possible condition requiring an emergency response exercise be conducted within six months after commencement of operation. According to EBPC, it discussed the draft conditions with first responders and all parties agreed that an emergency response exercise should be conducted, but that it should be a table top exercise with the objectives of:

* verification of respective roles and responsibilities;
* verification of notification matrix; and,
* verification of practices and procedures.

EC recommended that specific elements be included in EBPC's emergency prevention and response plans. EBPC agreed to EC's recommendation.

EC also recommended that emergency prevention and response plans be consistent with the CSA publication, *CAN/CSA-Z731-03 Emergency Pre-*

paredness and Response (CSA-Z731-03) and the *2004 Emergency Response Guidebook*. EBPC responded that its ERP would be consistent with CSA-Z731-03 and the OPR.

NEB Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
1	1	Irreversible	1	High

Adverse Effect
Not likely to be significant

Views of the Board

EBPC's proposed Environmental Management Framework includes programs aimed to prevent a leak or rupture. In the event of a leak or rupture, EBPC has set out the programs it would have in place to respond to emergencies. These programs would be aimed at eliminating or minimizing the negative effects of a leak or rupture and include cooperating with first responders and consideration of access to communities.

With respect to EBPC's comments on the proposed condition to conduct a table top emergency response exercise, the Board concludes that EBPC should conduct a full emergency response exercise within six months of commencement of operation of the Pipeline. The Board expects that EBPC, in organizing its emergency response exercise, would identify critical locations, for example, where access and egress by first responders may be impeded, and would focus its exercise upon those locations.

The Board is of the view that table top exercises can be very effective in testing certain elements such as communications systems, the effectiveness of continuing education programs, training programs, roles and responsibilities and parts of the ERP. However, table top exercises typically would not test elements such as the actual coordination and activation of a field response, first responders and company personnel knowledge and use of equipment, site security and site layout, to name a few.

With respect to EC's recommendation that emergency prevention and response plans be consistent with the *2004 Emergency Response Guidebook*, the Board notes that EBPC committed, and is required, to meet the provisions of the OPR, including requirements for emergency preparedness and response programs. In determining compliance with the OPR's emergency preparedness and response requirements, the Board references CSA-Z731-03 and other appropriate industry standards and documents, which could include the *2004 Emergency Response Guidebook*. Companies may also directly reference documents, such as the *2004 Emergency Response Guidebook*, to the extent that they are relevant to the company's emergency preparedness and response program.

If the Project were to receive regulatory approval, the Board recommends that the following conditions be imposed:

* EBPC shall file with the Board, at least sixty days prior to operation, an Emergency Procedures Manual (EPM) for the Project and shall notify the Board of any modifications to the plan as they occur. In preparing its EPM, EBPC shall refer to the Board letter dated 24 April 2002 entitled "Security and Emergency Preparedness Programs" addressed to all oil and gas companies under the jurisdiction of the NEB.
* EBPC shall file with the Board, at least sixty days prior to operation, evidence of consultation with stakeholders identified in the EPM, including a summary of any unresolved issues identified in consultations, and evidence that the EPM addresses, to the extent possible, any issues raised during consultation.
* Within six months after commencement of operation of the Project, EBPC shall conduct an emergency response exercise with the objectives of testing:
* emergency response procedures;
* training of company personnel;
* communications systems;
* response equipment;
* safety procedures; and
* effectiveness of its liaison and continuing education programs.
  EBPC shall notify the Board, at least thirty days prior to the date of the emergency response exercise, of the following:
* the date and location(s) of the exercise;
* the participants in the exercise; and
* the scenario for the exercise.

EBPC shall file with the Board, within sixty days after the emergency response exercise, a report on the exercise including:

* the results of the exercise;
* areas for improvement; and
* steps to be taken to correct deficiencies.

* Within six months after commencement of operation of the Project, EBPC shall file with the Board a description of the company's emergency response exercise program, including:

    * the frequency and type of exercises (full-scale, table-top, drill) it plans to conduct; and
    * how the results of any emergency response exercises will be integrated into the company's training and exercise programs.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations K, L, M, and N.

Given the Environmental Management Framework and the above recommendations, the Board concludes that it is unlikely that the Project would result in a pipeline leak or rupture leading to a fire. Therefore, the Board finds that the proposed Project would not likely cause significant adverse effects as a result of an accident or malfunction.

Further consideration of the evidence is required by the Board in order to fulfill its mandate under the NEB Act, which will form part of the content of separate Reasons for Decision.

7.3 Cumulative Effects Assessment

7.3.1 Scope of the Project

During the comment period on the draft EA Scoping Document, the NEB received requests to expand the scope of the Project to include the Canaport[TM] LNG Terminal. The complete Board ruling is attached as Appendix 4. Related to the LNG Terminal, the Board ruled that:

> ... the Canaport[TM] LNG Terminal has already undergone an environmental assessment by federal authorities under the CEA Act and by the Province of New Brunswick under provincial environmental assessment regulations. Since the LNG Terminal has already been the subject of a recent environmental assessment, the Board is of the view it should not include the Canaport[TM] LNG Terminal or the LNG tanker activity in the scope of the project for the environmental assessment of the Brunswick Pipeline Project. To do otherwise would be contrary to one of the CEA Act's stated purposes, that being the elimination of unnecessary duplication in the environmental assessment process. In addition, assessment of a project under the CEA Act is to occur at the proposal stage. The LNG Terminal was assessed at the proposal stage and is now under construction.
>
> However, within the scope of the assessment for the Brunswick Pipeline Project set out in the draft document, the terminal and tanker traffic can still be considered to the extent that they are relevant as cumulative envi-

ronmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out.

7.3.2 Views of EBPC

EBPC outlined the following sequential framework that it used for the assessment of project-related cumulative environmental effects in consideration of the requirements of the CEA Act and the NEB Filing Manual:

* Describe the spatial and temporal boundaries used to assess cumulative environmental effects.
* Describe the residual environmental effects of the Project.
* Describe other past, present, and likely future projects and activities, and the potentially measurable residual environmental effects of other projects and activities that may interact with the Project.
* Identify the potential interactions between the environmental effects of the Project with the environmental effects of the other projects and/or activities (cumulative environmental effects).
* Describe general and specific mitigation measures that are technically and economically feasible.
* Evaluate the significance of the resulting cumulative environmental effects.

EBPC listed the identified residual environmental effects of the Project in table 7.4.1 of its ESEA. Although residual environmental effects may occur during accidents, malfunctions and unplanned events, only those that are likely to occur (pursuant to the CEA Act) were carried forward into the cumulative environmental effects assessment.

EBPC indicated that it consulted with the NBDOE and the CEA Agency in selecting current and future projects that may have environmental effects that interact with those of the Project. Other projects were selected based on their proximity to the Project, the possibility of interactions with the environmental effects of the Project, and the likelihood of the other project(s) being carried forward (i.e., the project is registered with the Province under the New Brunswick *Clean Environment Act* or listed on the Canadian Environmental Assessment Registry). The spatial boundaries of the cumulative environmental effects assessment were Saint John County and Charlotte County.

EBPC submitted that it selected current and future activities (e.g., hunting and fishing) based on public and regulatory consultation, and the professional observations and opinions of members of the Jacques Whitford study team, its consultants for the ESEA.

Within its assessment of cumulative effects, EBPC identified land use actions and global actions as projects and activities with environmental effects that may act in combination with the residual environmental effects of the Project. Land use actions considered by EBPC included adjacent activities, existing RoWs, urbanization, and planned development projects. Adjacent activities included forest resource use, agricultural land use, watershed protection areas, rural residential land use, hunting, and fishing. Planned development projects included the Irving Oil LNG Marine Terminal and Multi-purpose Pier, the Irving Oil LNG and Marine Terminal Pond and Wetland Infilling, the Canaport[TM] LNG Terminal, and the Red Head Secondary Access Road along with 27 other projects in Charlotte County and Saint John County. The global actions focused on by EBPC were those having measurable environmental effects in the vicinity of the Project (i.e., regional air quality as a measurement of the cumulative emissions of global burning of fossil fuels acting on the regional airshed).

When asked by Mr. Thompson of FORP about whether a planned new oil refinery in the Red Head Mispec area was considered in the cumulative effects assessment, EBPC indicated that it was not considered. The CEA Act requires that you consider projects that are likely to take place. At the time of the ESEA, that project was not even known. EBPC submitted at that point, that project was just an idea.

EBPC identified potential interactions of the Project with the other projects and activities and then evaluated the significance of the resulting cumulative environmental effects. Potential interactions of effects were identified for:

* the atmospheric environment;
* water resources;
* fish and fish habitat;
* vegetation;
* wetlands;
* wildlife and wildlife habitat;
* land and resource use;
* infrastructure and services; and
* labour and economy.

For all of the cumulative environmental effects identified, EBPC predicted that the cumulative environmental effects of the Project in combination with other past, present and future projects and activities would not be significant, as measured against the criteria for significance it had identified. Therefore, no additional mitigation was recommended for minimizing the potential cumulative environmental effects of the Project.

Air Emissions

In response to concerns expressed by parties about cumulative effects of air emissions, EBPC referred to the evidence in its application and provided additional evidence on this topic. EBPC submitted that air emissions during construction of the pipeline would include carbon monoxide (CO) and carbon dioxide (CO[subscript 2]) emissions from construction equipment exhaust, welding procedures, and clearing activities if wood waste materials are burned on the RoW. Air emissions may also result during initial purging of the pipeline. EBPC provided an estimate of the forest loss in the City of Saint John in terms of a CO[subscript 2] sink and its air filtering capacity. EBPC concluded that there would be a negligible loss in CO[subscript 2] sink and filtering capacity from these areas by the removing of vegetation.

EBPC noted that during operation, natural gas (methane) emissions would occur during system blowdown and system purging, if required. Methane emissions would also include fugitive emissions due to venting from pneumatic devices, valve maintenance, launcher/receiver barrels, and meter stations. CO and CO[subscript 2] emissions would occur from the exhaust of maintenance vehicles and equipment. EBPC provided estimates of the quantity of fugitive methane emissions from the pipeline.

The standard mitigation that would be applied by EBPC for air emissions is outlined in Table 7.2.3.

In its evidence, EBPC identified Canadian and NB ambient air quality objectives. There are currently no air quality standards or guidelines for concentrations of greenhouse gases (GHG) in ambient air, nor are there any emission limits with respect to GHG releases from point sources on a local basis.

EBPC submitted that the Project itself would result in very low emissions of GHGs during the construction, and operation and maintenance phases. EBPC indicated that the estimated average fugitive GHG emissions from the Project of 8 579 tonnes CO[subscript 2]e/year equates to 0.04% of the provincial total. Compared to Canada's total in 2003 of 740 000 000 tonnes CO[subscript 2]e/year, the project would represent 0.001%.

EBPC concluded that cumulative effects on the atmospheric environment would not be significant because:

* cumulative contributions of air contaminants are not likely to result in an exceedance of the *NB Air Quality Regulation - Clean Air Act*, and would be temporary; and
* the Project would result in a relatively small loss of forest productivity (a carbon sequestration opportunity), a maximum of approximately 0.0004% of the Crown timber licenses it passes through, and during operation and maintenance, the RoW would be allowed to revegetate with the exception of removal of trees greater than approximately 1.5 m in height.

EBPC submitted that there are no GHG emissions of significance from the construction and operation of the Brunswick Pipeline. EBPC would employ various techniques and practices during construction and operation of the pipeline to minimize the release of GHG emissions. EBPC therefore concluded that any added or cumulative environmental effects would be negligible.

7.3.3 Views of the Parties

Interpretation of Cumulative Effects Assessment

The Eldridge-Thomases suggested that cumulative environmental effects that are likely to result from the Project in combination with other projects or activities, such as the LNG Terminal, tanker traffic and additional compressors on the M&NP US pipeline, are relevant. The effects suggested by the Eldridge-Thomases in the context of cumulative effects included:

* reduced tax revenues available to fund important environmental programs in the City;
* negative impacts upon the important fishery in the Bay of Fundy, the popular cruise ship industry from which Saint John enjoys great

benefit, the growing water-based tourism adventure industry (whale-watching, sea kayaking, deep sea fishing), private pleasure boating, and the scheduling of cargo ships and ferry traffic destined for the Port of Saint John;

* the possibility of a ship strike and mortality of a member of the very small remaining eastern Right whale population, which summers and rears its young in the Bay of Fundy;
* the addition of more CO_2 and other pollutants into the air on prevailing winds, that would be emitted by the extra compressors installed in order to carry extra volumes from the Project on the M&NP U.S. pipeline.

The Eldridge-Thomases concluded that taken together, the combined LNG plant, tanker traffic and associated pipeline components would incrementally add to the load on the local airshed, so that there is no net benefit from these projects, when consideration is given to who benefits from these emissions, and who bears the cost.

During the oral portion of the hearing, Dr. Thomas wanted to pursue further questioning on effects of tanker traffic within the context of cumulative effects, resulting in a ruling from the NEB that is attached as Appendix 8.

The Eldridge-Thomases argued that the NEB's ruling precluded inquiry that could have addressed the potential for, as a result of the Project, incremental increases in tanker traffic, increased CO_2 emissions from the LNG Terminal, or increased levels of other pollutants related to the regassification of LNG. They also argued that the artificial separation of the LNG Terminal project and the Brunswick Pipeline Project make rational planning of projects and rational energy policy virtually impossible. The Eldridge-Thomases argued that an LNG plant with an export pipeline must result in more gas processing at the plant than the LNG plant with no export pipeline, and associated environmental effects would result. They submitted that it is unclear when projects, such as a recently announced second oil refinery, should be included in cumulative effects assessment. The Eldridge-Thomases believe that the LNG plant and pipeline should undergo a joint environmental assessment.

Cumulative Effects of Air Emissions

The Pembina Institute (Pembina), on behalf of Ms. Teresa Debly, submitted that examining a natural gas pipeline as if it operates independently of natural gas production, transportation, and liquefaction/gasification effectively ignores the true broader impacts of such a Project's operations. It indicated that the NEB's scoping document makes direct reference to tanker traffic's relevance as a cumulative impact. Pembina understood this as tanker-related transportation activities. Pembina submitted that, by extension, other life-cycle activities must be considered as well. Therefore, Pembina considered the air emissions assessment it conducted to be consistent with the intent and requirements of the CEA Act.

Ms. Debly submitted Pembina's report on life-cycle air emissions of the Project. The spatial scope of Pembina's air contaminant emissions assessment included the Canaport[TM] LNG Terminal and the pipeline between the Terminal and the western boundary of the City of Saint John in order to focus on the Saint John airshed. The spatial scope of Pembina's GHG emissions assessment included the entire life-cycle of all activities associated with the pipeline: the manufacture of the materials in the pipeline, producing the natural gas, compressing/cooling the gas, transporting the gas, transferring the gas, transmitting the gas through the pipeline, and end use (combustion assumed) of the gas.

Pembina concluded that the absolute air contaminant emissions and GHG emissions of the construction, operation and maintenance, and decommissioning of the pipeline proper are not expected to generate significant adverse impacts on the environment or human health if examined independently of all other industrial activity in the Saint John area.

Based on its analysis, Pembina concluded that when the cumulative effects are considered, the Project and related activities may serve to exacerbate the air quality problems already experienced by the residents of Saint John. It also concluded that no single GHG source in Canada constitutes a significant proportion of Canada's total emissions; it is the accumulation of all sources that puts Canada among the most carbon-intensive countries in the world. The GHG emissions associated with the Project must be considered within NB and Canada's overall strategies.

EC submitted that there are numerous opportunities for reducing GHG emissions. Some best practices for reducing methane emissions from pipelines are described in the *Compendium of Methane and CO[subscript 2] Emission Reduction Measures for the Natural Gas Industry* and in the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*, and include the following:

* pre-installation of connected tees at any site with possible future service potential (to avoid line shutdowns);
* safe use of hot tapping or other techniques for future connections, or sleeve repairs for incidents;
* leak detection and repair programs, with regular maintenance checks of valves and fittings;
* state-of-the-art automatic closing valves should an incident occur;
* pipeline pigging practices and system gas control;
* optimization of pipeline system operation to avoid methane venting; and
* staff training and awareness.

EC encouraged EBPC to estimate GHG emissions from all project phases (e.g., installation, commissioning, operation, maintenance) and sources, consider and implement best practices available for GHG emissions reduction, and verify the effectiveness of these efforts.

Given public concern about this issue, HC recommended a contingency plan with proposed mitigative measures be created in the event that members of the public complain about localized air quality issues during pipeline construction. This would be particularly important if there are many residences within 300 m of the RoW (as the report indicates that any adverse effects are expected to be localized within 300 m of the RoW). Potential mitigative measures could include work slow-down or stoppage.

7.3.4 EBPC response to parties

In response to Pembina's analysis, EBPC indicated there are no GHG emissions of significance from the construction and operation of the Project. EBPC would employ various techniques and practices during construction and operation of the pipeline to minimize the release of GHG emissions. In addition, to the extent that customers in Canada or the US use natural gas from the Brunswick Pipeline to displace more carbon intensive fossil fuels, the resultant emissions of GHG may be reduced.

In response to EC's requests, EBPC provided average or typical annual fugitive methane emission rates for the Project and, from this, estimated the total annual GHG emissions expected from the Project. In addition, EBPC committed to ensuring pipeline operations staff be trained on the best practices referred to by EC and indicated that these best practices would be addressed in EBPC's Environmental Protection and Safety Management Plan.

In response to HC's recommendation, EBPC replied that the magnitude of emissions resulting from construction, and operation and maintenance of the Project is expected to be very small in comparison to emissions from other sources in the assessment area, and the potential environmental effects to ambient air quality resulting from the Project are not expected to be discernible from current levels. Any short-term, measurable environmental effects to air quality are likely to be localized to the specific area being worked on during construction, and relatively localized to the project area during operation and maintenance. EBPC has committed to mitigative measures to reduce air contaminant emissions that would be described in further detail in the EPP, which would be provided to the NEB and Province of NB for review and comment prior to its implementation.

An Intervenor asked EBPC about the potential for larger volumes of LNG arriving by ship at the Canaport[TM] Terminal as a result of the Project. EBPC submitted that there are no changes as a result of the Project to the design or capacity of the Canaport[TM] LNG Terminal from that described in the environmental impact statement (EIS) for the LNG Terminal, and there would be no incremental emissions from the LNG Terminal and no incremental tanker traffic at the Canaport[TM] LNG Terminal as a result of the pipeline.

Views of the Board

During the course of the proceeding, the NEB issued a ruling that discussed how cumulative effects assessments are carried out in the Board's process. This ruling is attached as Appendix 9 (NEB Ruling 7, A-27).

The NEB also issued two rulings related to the scope of the Project being assessed. The first ruling was attached to the Environmental Assessment Scoping Document and is attached as Appendix 4. The second ruling was issued during the oral portion of the hearing, and is attached as Appendix 8 (Dr. Thomas Request to Revisit the Scope of the Project). The Board's rulings were consistent in excluding the Canaport[TM] LNG Terminal and the LNG tanker activity from the scope of the Project for the environmental assessment of the Brunswick Pipeline Project since the Terminal has already been the subject of a recent environmental assessment, but in allowing consideration of the Terminal and tanker traffic to the extent that they are relevant as cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out.

Within the framework set out in these rulings, the initial step of identifying residual effects of the Project being assessed considers only residual effects of the Brunswick Pipeline Project, with the scope of the Project defined in the Environmental Assessment Scoping Document included in Appendix 4. The evidence before the Board indicates that there would be no changes as a result of the Project to the design or capacity of the Canaport[TM] LNG Terminal from that described in the EIS for the LNG Terminal. There is no evidence that there would be any activity within the Bay of Fundy as part of the Project, and therefore there would be no effects on or from boating or shipping in the Bay. Consequently, effects on boating or shipping in the Bay are not relevant to the cumulative effects assessment. Effects from boating or shipping, including tanker traffic, are only relevant as effects of other projects or activities, discussed further below. Tax revenues are not environmental effects, and therefore are not considered as part of the EA of the Project.

With respect to other projects to consider in a cumulative environmental effects assessment, the NEB has ruled in the past that the other projects considered in a cumulative effects assessment cannot be hypothetical.[52]

The Courts have said that the decisions of RAs are not required to "consider fanciful projects by imagined parties producing purely hypothetical effects".[53] The Board is of the view that EBPC's methods for identifying other projects for consideration in the cumulative effects assessment were appropriate.

The context in which effects of other projects or activities are considered is when the effects of the other projects or activities act in combination with the residual effects predicted for the Brunswick Pipeline Project upon a biophysical or socio-economic element. Effects on fish and fish habitat and on the atmospheric environment, as well as effects on other biophysical and socio-economic elements, have been considered in this context.

Given the minimal project-related emissions that could affect air quality and their short-term nature, the Board is satisfied that any residual emissions that could combine with emissions from other projects and activities to act cumulatively would be negligible and not likely to be significant.

The Board notes that EBPC defined a significant residual adverse environmental effect on air quality in terms of GHG emissions as one that results in a substantive increase to provincial releases (i.e., [greater than]1% of total provincial GHG emissions, expressed as CO[subscript 2] equivalents). EC submitted that without sufficient explanation or reference to the significance or validity, that this criterion is arbitrary and bears no special significance.

The Board notes that, at the present time, there are no defined criteria to measure significance in relation to GHG when considered in an environmental assessment. However, comparisons to provincial or national emissions levels can provide a useful context for evaluating projects. While no specific criterion for significance has been established, considering the GHG emissions of the Project compared to provincial and federal levels of GHG emissions, the Board is satisfied that the GHG emissions of the Project are very low. As a result, the incremental effects of the GHG emissions of the Project are not likely to be significant.

With respect to other potential cumulative environmental effects, the Board notes that the discussion of some of the environmental effects earlier in this Report have taken into account the effects of other projects and activities. For example, the consideration of effects from increased access by ATVs and effects on wetlands already considers the existing environment, including the effects that have been experienced from past projects and activities. The discussion of the effects of noise took into account the noise that would be experienced as a result of the Project combined with other projects and activities at the time of construction. Therefore, these effects have not been discussed further within this section.

Given the nature of the Project, EBPC's proposed mitigation measures, the recommendations of the Board, and the limited extent of any residual effects, the Board finds that significant adverse cumulative effects of the Project are unlikely.

7.4 Capacity of Renewable Resources

Pursuant to subsection 16(2) of the CEA Act, this EA included consideration of the capacity of renewable resources that are likely to be significantly affected by the Project to meet the needs of the present and those of the future.

7.4.1 Views of EBPC

EBPC submitted that the capacity of renewable resources likely to be affected by the Project to meet the needs of the present and those of the future was considered during its evaluation of significance for each of the environmental effects identified and evaluated.

EBPC identified and analyzed environmental effects on renewable resources including the atmospheric environment (air quality, acoustic environment), water resources, fish, vegetation, wetlands, and wildlife. EBPC's ESEA also identified and analyzed effects of the Project on land and resource use, such as residential, recreational, and commercial land use, as well as forestry and agriculture.

7.4.2 Views of the Parties

No comments were made by other parties specifically with respect to the capacity of renewable resources that are likely to be significantly affected by the Project to meet the needs of the present and those of the future. Comments provided by parties to the hearing in the context of specific effects on environmental components have been addressed in the environmental effects analysis in sections 7.1 through 7.3.

Views of the Board

The Board notes that for each of the renewable resources potentially affected by the Project, various sections of this Report provide a consideration of whether significant adverse effects to the "capacity" of that resource are likely to occur. The nature of potential effects to the capacity of renewable resources was considered along with criteria for evaluating significance, such as the length of time for recovery.

The Board finds that given the nature of the Project, the mitigation measures that would be implemented and the recommendations of the Board, the Project is not likely to cause significant adverse environmental effects on renewable resources.

7.5 Follow-Up Program

A "follow-up program" under the CEA Act is defined as "a program for verifying the accuracy of the environmental assessment of a project, and determining the effectiveness of any measures taken to mitigate the adverse environmental effects of the project."

The NEB must recommend a follow-up program for the Project as part of this EA.

EC recommended that a follow-up program should specify sites at which monitoring was conducted. Baseline data should be collected prior to clearing to enable future comparisons with follow-up data, and to facilitate planning for a decommissioning and site restoration phase. Monitoring should continue until it is determined by the NEB that the environmental component under study has been restored or the particular impact has been mitigated in a satisfactory manner.

Views of the Board

Baseline information is required in order to carry out a follow-up program, and therefore the collection of appropriate baseline data should be a consideration in the design of a follow-up program. Based on the nature of the environmental component, potential environmental effects of the Project, and the follow-up studies planned, the design of the follow-up program should also establish an appropriate follow-up period and schedule for reporting on the results of the program. In designing the follow-up programs for this Project, the Board expects that EBPC would plan an appropriate follow-up period and reporting schedule and would consult with relevant regulatory agencies and stakeholders on the design of its follow-up programs.

The Board has considered the need for, and requirements of, follow-up programs in the environmental assessment. This need has been discussed in relevant sections of the environmental effects analysis in this Report. If the Project were to receive regulatory approval, the Board recommends that the following condition be imposed.

* EBPC shall file with the Board for approval, at least sixty days prior to construction, a description of planned follow-up programs as required by the CEA Act. The programs shall be designed to verify the accuracy of the environmental assessment predictions and to assess the effectiveness of mitigation for:
* fish and fish habitat as outlined in the Brunswick Pipeline Project ESEA (Volume 1);
* wetlands as outlined in the Brunswick Pipeline Project ESEA (Volume 1);
* access management as detailed in the Access Management Plan (recommendation G);
* horizontal directional drill (HDD) noise management (recommendation H); and
* reclamation of Rockwood Park (recommendation B(5)).

Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board. The description of follow-up programs shall include a schedule for the submission of follow-up reports to the Board and the results of the follow-up programs shall be filed with the Board based on that schedule.

Therefore, the Board has included recommendations to this effect in section 9.2 as recommendations C and P.

If the Project were to receive regulatory approval and be constructed, the NEB would continue to have regulatory oversight of the Project for the life of the Brunswick Pipeline. Beyond the requirements for follow-up under the CEA Act, the OPR contain requirements related to environmental management that would apply to the Project throughout its life, and these requirements would be monitored and enforced by the NEB.

8.0 COMMENTS ON THE SUBSTITUTION PROCESS

The Board considers the pilot substitution process under the CEA Act to have been a success. The Board's hearing process met the following objectives.

- **CEA Act Requirements**: The process considered the full scope of the environmental assessment as set out in the Environmental Assessment Scoping Document in Appendix 4.
- **Public Access**: Information about the process being undertaken, including the environmental assessment scoping document, and the evidence considered as part of the process was available to the public.
- **Public Participation**: The process included opportunities for the public to convey their views to the Board's hearing panel, including written and oral presentations.
- **Reporting to Government**: The Board completed this EA Report for submission to the Minister of the Environment and the RA Ministers.

The NEB wishes to acknowledge the effort of its federal partners toward streamlining the regulatory process while maintaining the breadth and quality of the environmental assessment. The hearing process, as an integrated process considering environmental assessment as well as other issues relevant to the public interest, allowed the Board to hear from a broad spectrum of participants on a wide range of issues. The input was significant to the Board in its deliberations.

The success of this pilot project was made possible through the commitment and cooperation of the CEA Agency, federal departments involved in the environmental assessment as well as the participation of the people of New Brunswick who shared their views with the Board through written and oral presentations. The NEB also recognizes the cooperation of EBPC and its consultants.

The Board sincerely thanks all who participated in or otherwise supported this hearing and in particular the Board thanks the people of New Brunswick.

9.0 THE NEB'S CONCLUSION AND RECOMMENDATIONS

9.1 Conclusion

Pursuant to the CEA Act, the Board was charged with reviewing the environmental effects of the Project and the appropriate mitigation measures, and setting out its rationale, conclusions and recommendations, including any mitigation measures and follow-up programs in its EA Report.

This Report reflects the Board's review of the environmental effects of the Project and appropriate mitigation measures based on the Project description, factors considered during the review, and the scope of the factors. Throughout the Report, the Board has made a number of recommendations that, if included as conditions in any Certificate should the Project be approved under the NEB Act, would ensure that appropriate mitigation would be implemented. Further discussion regarding how these conditions would apply if the Project were to receive regulatory approval, and the Board's lifecycle approach to regulating pipelines, will be included in subsequent Reasons for Decision.

Provided all environmental commitments made by EBPC in its application and undertakings given by EBPC during the GH-1-2006 proceeding are implemented, and the Board's recommendations imposed as conditions to any Certificate, the Board finds that the Project is not likely to result in significant adverse environmental effects. Therefore, the Board recommends that the Project be allowed to proceed to regulatory and departmental decision-making.

9.2 Recommendations

In addition to the commitments EBPC has made throughout this proceeding, for example, those related to ongoing consultation, continuing education programs for First Responders and public awareness programs, the Board has a number of recommendations arising from its EA, the rationales for which are more fully discussed in the sections above.

It is recommended that in any Certificate that the NEB may issue, the following recommendations be attached as conditions of approval.

A. General

EBPC shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included or referred to in its application or as otherwise agreed to during questioning or in its related submissions.

B. Environmental Protection Plan

EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a project-specific Environmental Protection Plan (EPP). This EPP shall be a comprehensive compilation of all environmental protection procedures, mitigation measures, and monitoring commitments, as set out in EBPC's application for the Project, subsequent filings, evidence collected during the hearing process, or as otherwise agreed to during questioning or in its related submissions. The EPP shall describe the criteria for the implementation of all procedures and measures, and shall use clear and unambiguous language that confirms EBPC's intention to implement all of its commitments. Construction shall not commence until EBPC has received approval of its EPP from the Board.

The EPP shall address, but is not limited to, the following elements:

1) environmental procedures including site-specific plans, criteria for implementation of these procedures, mitigation measures and monitoring applicable to all project phases and activities;
2) site-specific construction plans for wetlands where they cannot be avoided;
3) site-specific plans for habitat harboring Species at Risk and of Conservation Concern where it cannot be avoided;

4) project-specific acid rock drainage mitigation measures;
5) a construction and reclamation plan for Rockwood Park with evidence demonstrating consultation with stakeholders;
6) a reclamation plan which includes a description of the condition to which EBPC intends to reclaim and maintain the right of way once the construction has been completed, and a description of measurable goals for reclamation; and
7) evidence of consultation with relevant regulatory authorities that either confirms satisfaction with the proposed mitigation or summarizes any unresolved issues with the proposed mitigation.

C. Environmental Follow-up Programs

EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a description of planned follow-up programs as required by the *Canadian Environmental Assessment Act*. The programs shall be designed to verify the accuracy of the environmental assessment predictions and to assess the effectiveness of mitigation for:

* fish and fish habitat as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);

* wetlands as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);

* access management as detailed in the Access Management Plan (recommendation G);

* horizontal directional drill (HDD) noise management (recommendation I); and

* reclamation of Rockwood Park (recommendation B(3)).

Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board.

These descriptions of follow-up programs shall include a schedule for the submission of follow-up reports to the Board.

D. Traditional Ecological Knowledge Study Recommendations

EBPC shall file with the Board, at least sixty (60) days prior to construction, an update on the implementation of the six recommendations identified in the Traditional Ecological Knowledge Study (July 2006).

E. Construction Inspection Program

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a construction inspection program. The program shall include:

1) a preliminary list of the number and type of each inspection position, including job descriptions, qualifications, roles, responsibilities, and decision-making authority;
2) a discussion of how any changes to the items outlined in (1) would be determined during the course of construction; and
3) the reporting structure of personnel responsible for inspection of the various pipeline construction activities, including environment and safety.

F. Archaeological Studies and Monitoring Plan

EBPC shall consult with the Archaeological Services Unit of New Brunswick on further studies and a monitoring plan for areas with high potential for heritage resources, once the locations for detailed right of way, facility sites and temporary work space have been determined. EBPC shall file with the Board, at least thirty (30) days prior to construction:

1) for approval, a report that documents how archaeological and heritage resources within the detailed route have been identified, recorded and mitigated;
2) copies of any correspondence from, or a summary of any discussions with the Archaeological Services Unit of New Brunswick regarding the acceptability of EBPC's report and proposed mitigation measures; and
3) for approval, a copy of any proposed monitoring plan.

G. Access Management Plan

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a project-specific Access Management Plan that includes:

1) EBPC's goals and measurable objectives regarding the Access Management Plan;
2) the methods and procedures to be used to achieve the mitigation goals;
3) the criteria to determine if the mitigation goals have been met;
4) the frequency of monitoring activities along the right of way;
5) a description of the adaptive measures that will take place in the event that access management measures are ineffective; and

6) evidence of consultation with relevant regulatory authorities and landowners that either confirms satisfaction or summarizes any unresolved issues with the proposed mitigation.

Construction shall not commence until EBPC has received approval of its Access Management Plan from the Board.

H. HDD Noise Management Plan

EBPC shall file for approval, at least ninety (90) days prior to the start of the HDD activity proposed for the Saint John River Crossing, a detailed noise management plan containing information on day-time and night-time HDD operations at the drill exit and entrance sites, including but not limited to the following:

1) ambient sound levels at noise-sensitive areas close to the HDD exit and entrance sites to establish a baseline for assessing potential noise impacts;
2) predicted noise level at the most affected residences caused by the HDD without mitigation;
3) proposed HDD noise mitigation measures, including but not limited to the following:

    i. all technologically and economically feasible mitigative measures as presented in Section 5.1.7 of the Environmental and Socio-Economic Assessment (Jacques Whitford, 2006) and in the Resource Systems Engineering assessment;
    ii. the use of full enclosures on diesel powered units;
    iii. the use of quiet machinery (where feasible);
    iv. the undertaking of HDD activities during periods where residential windows would be expected to be closed (i.e., during winter months);

4) predicted noise level at the most affected residences with implementation of the mitigation measures;
5) noise contour map(s) showing the potentially affected residences at various noise levels;
6) a noise monitoring program including locations, methodology and schedule;
7) confirmation that residents potentially affected by HDD noise will receive contact information for EBPC in the event they have concerns about the HDD noise;
8) a contingency plan with proposed mitigative measures for addressing noise complaints, which may include the temporary relocation of specific residents; and

9) confirmation that EBPC will provide notice to nearby residents in the event that a planned blowdown is required and that planned blow-downs will be completed during day-time hours whenever possible.

I. Saint John River Crossing

EBPC shall construct the crossing(s) of the Saint John River using the HDD method or, if this is not feasible, shall apply to the Board for approval of an alternative crossing technique and include an environmental assessment of the proposed alternative with its application.

J. Archaeological or Heritage Resource Discovery

EBPC shall notify the Board, at the time of discovery, of any archaeological or heritage resources and, as soon as reasonable thereafter, file with the Board for approval a report on the occurrence and proposed treatment of the archaeological/heritage resources, any changes to the archaeological/heritage monitoring plan, and the results of any consultation, including a discussion on any unresolved issues.

K. Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, an Emergency Procedures Manual (EPM) for the Project and shall notify the Board of any modifications to the plan as they occur. In preparing its EPM, EBPC shall refer to the Board letter dated 24 April 2002 entitled "Security and Emergency Preparedness Programs" addressed to all oil and gas companies under the jurisdiction of the National Energy Board.

L. Consultation on Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, evidence of consultation with stakeholders identified in the EPM, including a summary of any unresolved issues identified in consultations, and evidence that the EPM addresses, to the extent possible, any issues raised during consultation.

M. Emergency Response Exercise

1) Within six (6) months after commencement of operation of the Project, EBPC shall conduct an emergency response exercise with the objectives of testing:

* emergency response procedures;

* training of company personnel;
* communications systems;

* response equipment;
* safety procedures; and
* effectiveness of its liaison and continuing education programs.

2) EBPC shall notify the Board, at least thirty (30) days prior to the date of the emergency response exercise, of the following:

* the date and location(s) of the exercise;
* the participants in the exercise; and
* the scenario for the exercise.

3) EBPC shall file with the Board, within sixty (60) days after the emergency response exercise outlined in (1), a report on the exercise including:

* the results of the exercise;
* areas for improvement; and
* steps to be taken to correct deficiencies.

N. Emergency Response Exercise Program

Within six (6) months after commencement of operation of the Project, EBPC shall file with the Board a description of the company's emergency response exercise program, including:

* the frequency and type of exercises (full-scale, table-top, drill) it plans to conduct; and
* how the results of any emergency response exercises will be integrated into the company's training and exercise programs.

O. Post-construction Environmental Reports

Within six (6) months following commencement of operation of the Project, and on or before the 31st of January following each of the second (2nd) and fourth (4th) complete growing seasons following commencement of the operation of the Project, EBPC shall file with the Board a post-construction environmental report that:

1) identifies on a map or diagram any environmental issues that arose during construction;
2) provides a discussion of the effectiveness of the mitigation applied during construction;
3) identifies the current status of the issues identified, and whether those issues are resolved or unresolved; and
4) provides proposed measures and the schedule EBPC shall implement to address any unresolved issues.

P. Environmental Follow-up Program Reports

EBPC shall file with the Board, based on the schedule referred to in Recommendation C, the report(s) outlining the results of the follow-up programs.

National Energy Board

Environmental Assessment Report

Brunswick Pipeline Project

Sheila Leggett
Panel Chair

Kenneth Bateman
Member

Strater Crowfoot
Member

10.0 NEB CONTACT

David Young
Acting Secretary
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta T2P 0X8
Phone: 1-800-899-1265
Facsimile: 1-877-288-8803
secretary@neb-one.gc.ca

APPENDIX 1: Project-Related Advice Provided by RAs, FAs, and Provincial

Department/ Agency	Role	Summary of Comments
Canadian Transportation Agency	Possible RA	CTA did not provide any submissions.
DFO	RA	DFO declared itself a Government Participant in the hearing process. No other submissions were received from DFO during the course of the proceedings.
Health Canada	FA with	Health Canada declared

	specialist Government advice	itself a Participant in the hearing process. In its written evidence dated 20 September 2006, Health Canada provided comments regarding air quality, noise and vibration, drinking water, country foods, and socio-economic considerations. In this evidence, Health Canada made specific recommendations related to monitoring of air quality, addressing potential for noise from construction and blowdowns, and post-construction groundwater monitoring. Health Canada provided additional information about its comments related to noise in response to information requests from EBPC and the Board. In a letter dated 3 November 2006, Health Canada provided further information clarifying its comments on noise related to the HDD of the Saint John River, and indicating that its concerns were resolved as long as specific mitigation would be implemented. In a letter dated 15 November 2006, Health Canada provided comments on a possible certificate condition related to an HDD noise management plan. These comments have been incorporated into the NEB's recommendation H.
Transport Canada	RA	Transport Canada provided a letter of comment dated September 11, 2006. In its letter of comment, Transport Canada provided information about its mandate and requirements related to the roject under the *Navitgable Waters Protection Act*,

		the NEB Act, and the *Transportation of Dangerous Goods Act*. The letter also informed EBPC that if any "work" is placed in, on, under, through, or across navigable water, EBPC is required to submit an application for approval.
EC	Possible RA	EC was an Intervenor in the hearing process. In its evidence dated 20 September 2006, EC provided various comments related to: * Preventing impacts to wildlife and habitat * Risk assessment and environmental emergencies * Preventing impacts to water quality * Considering alternative means involving disposal at sea It also provided specific recommendations related to: * Route selection and corridor width * Migratory birds and forest habitats * Wetlands and wetland functions * Wildlife at risk and of conservation concern * Quantitative risk assessment * Environmental emergency prevention and response planning * Acid rock drainage * Hydrostatic testing * Horizontal directional drilling * Assessing alternative means involving disposal at sea EC provided additional information about its comments related to spill response in response to an information request from EBPC. EC also submitted final argument reiterating its recommendations and providing comments on possible certificate conditions.
NRCan	FA with specialist advice	NRCan declared itself a Government Participant in the hearing process.

		In its evidence dated 20 September 2006, NRCan provided comments regarding acid rock drainage and metal leaching; groundwater and hydrogeology; and seismicity. In this evidence, NRCan made specific recommendations related to acid rock management and groundwater studies.
NBDOE	Provincial department with an EA responsibility	NBDOE was an Intervenor in the hearing process. In its application for intervention, NBDOE indicated that the Province of New Brunswick has always been and continues to be interested in appropriate economic development, including energy infrastructure projects that will benefit its citizens while ensuring that potential environmental impacts, including socio-economic impacts, of any development proposals are adequately addressed. As part of its evidence, EBPC submitted comments it had received from the New Brunswick Technical Review Committee, led by the NBDOE, on EBPC's ESEA for the Project. In its submission, EBPC also provided its response to those comments. The comments were on a wide variety of topics addressed in EBPC's ESEA In its final argument, NBDOE reiterated its comments from its application for intervention.

APPENDIX 2: Substitution Requirements

Canadian Environmental Assessment Agency
Agence canadienne d'évaluation environnementale

President
Président

160 Elgin St., 22nd floor
Ottawa ON K1A 0H3
160, rue Elgin, 22e étage
Ottawa ON K1A 0H3

MAR 21 2006

Mr. Kenneth W. Vollman
Chairman
National Energy Board
444 Seventh Avenue SW
Calgary Alberta T2P 0X8

Dear Mr. Vollman:

The Canadian Environmental Assessment Agency (the Agency) has received a copy of the letter addressed to Minister Ambrose dated March 16, 2006 in which the National Energy Board has requested that the Minister refer the Brunswick Pipeline Project to a review panel. Further, in your letter, you have requested that the Minister approve the substitution of the National Energy Board process for an environmental assessment by a review panel pursuant to subsection *43(1)* of the *Canadian Environmental Assessment Act*.

In preparing its recommendation to Minister Ambrose, the Agency would like to be able to confirm that:

- the substituted process for the Brunswick Pipeline Project (substituted process) shall apply fully the scope of assessment, factors to be considered and scope of factors as set out in the *Environmental Assessment Scoping Document* provided as Attachment 1 to your referral letter;

- the substituted process shall make the *Environmental Assessment Scoping Document* publicly available;

- the substituted process shall include informal opportunities for the public to convey their views to the National Energy Board hearing panel, including written and oral presentations;

- on the completion of the environmental assessment, the National Energy Board shall submit a report (Report) to the Minister of the Environment and the responsible authority Ministers;

.../2

- the Report submitted to the Minister of the Environment shall set out the National Energy Board's rationale, findings, conclusions and recommendations, including:

  - any mitigation measures that should be implemented with respect to the project,

  - the follow-up program that the National Energy Board recommends;

  - the National Energy Board shall publish the Report;

  - the National Energy Board has agreed, that for this project only, the Agency shall administer the Participant Funding Program for the substituted process;

  - the National Energy Board shall assist the Agency in ensuring that the successful applicants from the Participant Funding Program have applied for and received intervener status in the hearings before the Agency enters into any contribution agreements;

  - following the submission of the Report to the Minister of the Environment, the National Energy Board shall provide the Agency with a report on the participation of the successful Participant Funding applicants in the hearing process ensuring that those successful applicants provided evidence at the hearing regarding the factors considered or other issues related to the environmental assessment and/or provided the same in writing.

Following confirmation from the National Energy Board of its commitment to the above, the Agency will proceed with its recommendation to Minister Ambrose and will inform you of her decision.

Yours sincerely,

Jean-Claude Bouchard

Jean-Claude Bouchard

c.c.: Ted Currie, Fisheries and Oceans Canada
Carl Ripley, Transport Canada
Friederike Kirstein, Environment Canada
Sarah Olivier, Natural Resources Canada
Tony Henderson, Health Canada
Bill Aird, Canadian Transport Agency
Paul Vanderlaan, New Brunswick Department of Environment and Local Government

National Energy Board

Office national de l'énergie

Office of the Chairman

Bureau du Président

27 March 2006

Mr. Jean-Claude Bouchard
President
Canadian Environmental Assessment Agency
160 Elgin Street, 22nd Floor
Ottawa, (Ontario) K1A 0H3

Brunswick Pipeline Project – Substituted Process Commitments

Dear Mr. Bouchard,

The National Energy Board has received your letter dated 21 March 2006 requesting that the Board confirm its commitment to the list of requirements for a substituted process for the proposed Brunswick Pipeline Project (the Project) prepared by the Canadian Environmental Assessment Agency (the Agency) and outlined in the letter. The Board has reviewed the list of requirements for the substituted process and is committed to meet those requirements in conducting its review of the Project.

Thank you very much for working with the Board to bring our recommendations and requests related to the Project to Minister Ambrose. The NEB looks forward to working with our colleagues at the Agency to deliver a rigorous, timely and harmonized federal environmental assessment of the Project.

Sincerely,

Kenneth W. Vollman,
Chairman

c.c.

Fisheries and Oceans Canada
Mr. Ted Currie, Habitat Assessment Biologist
343 University Avenue
Moncton, New Brunswick E1C 9B6
Facsimile (506) 851-2565

.../2

Transport Canada
Mr. Carl Ripley, Environmental Officer
95 Foundry Street, PO Box 42
Moncton, New Brunswick EIC 8K6
Facsmile (506) 851-7542

Environment Canada
Ms. Friederike Kirstein
Environmental Stewardship Branch
16th Floor, Queen's Square, 45 Alderney Drive
Dartmouth, NS B2Y 2N6
Facsmile (902) 426-8373

Natural Resources Canada
Ms. Sarah Olivier, Environmental Assessment Officer
580 Booth Street, 3rd Floor
Ottawa, Ontario K1A 0E4
Facsimile (613) 995-5719

Health Canada
Mr. Tony Henderson, Regional Environmental Assessment Coordinator
Suite 1625, 1505 Barrington Street
Halifax, Nova Scotia B3J 3Y6
Facsimile (902) 426-6676

Canadian Transportation Agency
Mr. Bill Aird, Senior Environmental Assessment Officer
15 Eddy Street
Hull, Quebec K1A 0N9
Facsimile (819) 953-5564

New Brunswick Department of Environment and Local Government
Mr. Paul Vanderlaan, Director, Project Assessment
Marysville Place, P.O. Box 6000
Fredericton, New Brunswick
Facsimile (506) 453-2627

Canadian Environmental Assessment Agency
Mr. Bruce Young, Director, Panel Management
Place Bell Canada 160 Elgin Street, 22nd Floor
Ottawa, Ontario K1A 0H3
Facsimile (613) 957-0941

Mr. Derek McDonald, Senior Program Officer
1801 Hollis Street, Suite 200
Halifax, Nova Scotia B3J 3N4
Facsimile (902) 426-6550

Minister of the Environment Ministre de l'Environnement

Ottawa, Canada K1A 0H3

0 3 MAI 2006

RECEIVED - REÇU
NATIONAL ENERGY BOARD
MAY 10 2006
CHAIRMAN - PRÉSIDENT

Mr. Kenneth W. Vollman
Chairman
National Energy Board
444 Seventh Avenue South West
Room 4047
Calgary AB T2P 0X8

Dear Mr. Vollman:

Thank you for your letter of March 16, in which the National Energy Board (NEB) has requested that I refer the Brunswick Pipeline Project to a review panel. Further, in your letter, you have requested that I approve the substitution of the NEB process for an environmental assessment by a review panel pursuant to subsection 43(1) of the *Canadian Environmental Assessment Act* (the Act).

I am also aware of the letter addressed to you, dated March 21, and signed by the President of the Canadian Environmental Assessment Agency (the Agency) in which the President was seeking confirmation of your commitment to a list of conditions for a substituted process. I understand that you have responded to the Agency in a letter dated March 23, indicating that you are committed to meeting those conditions set out in the Agency's letter of March 21.

I am pleased to inform you that based on your commitments made in your letters of March 16 and 23, I am referring the project to a review panel and I am approving your request for substitution of the NEB process for an environmental assessment by a review panel pursuant to subsection 43(1) of the Act. I look forward to the receipt of your report.

Please accept my best wishes.

Yours sincerely,

Rona Ambrose

Rona Ambrose

c.c.: The Honourable Loyola Hearn , P.C., M.P.
The Honourable Lawrence Cannon, P.C., M.P.
The Honourable Gary Lunn, P.C., M.P.
Ms. Marian L. Robson, President of the Canadian Transportation Agency

Canada

APPENDIX 3: Comments Received by the NEB on Draft environmental Assessment Scoping Document

Stakeholder	Summary of Comments
Bear Head LNG Corporation	Project-specific direction on the scope of alternatives to be considered should be given, specifically, direct connections to Canada's Maritimes gas market should be considered
Ian and Deborah Benjamin	Oppose three land routes for pipeline because of effects on Rockwood Park, risk to hospital
	Want an independent assessment of the costs of the undersea route
Carol Blomsma	Concerned about routing through the City
Dorothy Dawson	Concerned about route through the City, prefers underwater route
Teresa Debly	Concerns about water tables, air shed, effects on wildlife from blasting, and noise should be addressed
EBPC	Current scope is appropriate
EC	Concurs with the draft scoping document as presented
Friends of Rockwood Park	The following topics should be addressed in the environmental assessment:

* Detailed examination of undersea route
* Consequences of accidents and malfunctions
* Emergency response
* Related to Rockwood Park: construction methods, noise, caves, lakes and ponds, ATVs, flora and fauna, fossils
* Construction disturbance to community
* Relationship between Irving Repsol LNG Terminal and Brunswick Pipeline
* Effects of Brunswick Pipeline combined with Irving Repsol LNG Terminal
* Gas emissions through venting or leakage
* Security
* Marsh Creek flood plain
* Temperature of buried pipeline
* Cumulative effects of industrialization
* Property value, tax, and insurance
* Employment for pipeline construction
* Effects on land use near the pipeline
* Liability
* Gas supply
* Social capital in Saint John
* City infrastructure
* Vegetation control along pipeline corridor
* Soil contamination

Ken Golding	Not concerned about route; tax revenue and safety are important Consider automatic closing of pipeline valves and review the number of valve stations planned for Saint John
Dennis Griffin	Would like more information about the routing
Patty Higgins	Concerns about impact of LNG tankers, effects on air shed, and contaminated soil should be addressed
William Johnston	Opposes the pipeline

Betty Lizotte	Consider effects on Rockwood Park, including lakes, wild-life, and trees. Prefers undersea route
Fred London	Concerned about routing through the Park and the City
Bob McDevitt	Prefers route under the Bay of Fundy to avoid danger to citizens and Rockwood Park
Scott O'Leary	Opposes pipeline route, prefers route under the Bay for safety reasons
Dan Robichaud	Concerned about emergency response
Saint John Citizens Coalition for Clean Air	The following topics should be addressed in the environmental assessment:

* Effects of change in ownership of the project

- Effects from trespass on ATVs
- Assessment of communication system, power supply required to service site
- Comprehensive list and analysis of malfunctions or accidents
- Psychosocial health impacts
- Assessment of the underwater route under the Bay of Fundy
- Effects on air from tree removal, construction emissions at the airshed level
- Need for the Project and alternatives to the Project should be mandatory topics, supply of LNG
- City of Saint John tax concession
- Community knowledge about worries, complaints, ideas, alternatives and personal impacts

* Consideration of other projects or activities that have been or will be carried out, such as the oil refinery upgrade, possibility for petrochemical facilities
* Local availability of natural gas from the Project
* Security
* Pipeline safety

Horst Sauerteig	Submarine route should be considered and detailed investigations of the sea- and sub-sea floor and related geotechnical and geophysical conditions should be carried out for consideration
Michael Saunders	Opposes route through the City, prefers under water route
Abigail Teed-Walton	Opposes route through residential areas of Saint John and Rockwood Park, prefers route through the Bay of Fundy
Dr. Leland Thomas	Should also include the environmental effects of the Canaport LNG plant Research should be carried out into the location of the stated supply for the Brunswick Pipeline
Carol Ring	Protests route through Rockwood Park and residential areas of Saint John Only acceptable route is through Bay of Fundy
Ruth Vincent	Concerned about pipeline routing related to safety
Don Watson	Concerned about safety, emergency response and associated costs Prefers marine route

SarahRose Werner Concerned about effects of drilling and blasting

APPENDIX 4: Board Ruling - Environmental Assessment Scoping Document (Letter dated 23 June 2006)

The Brunswick Pipeline Project (the Project) is aimed at the construction of a natural gas transmission pipeline from the Canaport[TM] Liquefied Natural Gas (LNG) Facility at Mispec Point, near Saint John, New Brunswick (currently under construction), to an export point at the Canada-US border.

In May 2006, the National Energy Board (NEB or Board) released for public comment a draft Environmental Assessment Scoping Document for the Brunswick Pipeline Project that included input from the other federal and provincial departments involved in the environmental assessment of the Project. The deadline for comments was 7 June 2006.

The public comments received generally fell into three categories:

1. requests for specific issues or pieces of information to be considered as part of the environmental assessment, or concerns expressed about the Project, that fall within the existing scope of the factors for the assessment, such as environmental effects of the proposed route and effects of accidents and malfunctions;
2. requests for additional factors to be considered as part of the environmental assessment, or concerns expressed about the Project, where the factors fall within the list of issues considered within the NEB's regulatory mandate under the *National Energy Board Act* rather than its environmental assessment mandate under the *Canadian Environmental Assessment Act* (CEA Act). These factors include the safety of the design and operation of the proposed facilities, the economic feasibility of the proposed facilities, and the potential environmental and socio-economic effects of the proposed facilities; and,
3. requests to expand the scope of the Project to include the Canaport[TM] LNG facility or expand the scope of the factors to include other factors that are not currently included in either the scope of the assessment or the list of issues within the Board's regulatory mandate.

With respect to items in the first category, the Board is satisfied that since the issues raised are within the scope of the assessment as described in the draft document, the scope is adequate.

With respect to items in the second category, the Board is of the view that these issues are not covered by the scope of the assessment as described in the draft document, but are covered by the broad issues in the List of Issues attached as Appendix I to the Board's Hearing Order GH-1-2006. Since these broad issues have already been identified by the

Board for discussion in the proceeding, while they are outside of the scope of the environmental assessment, they will be considered within the Board's proceeding which considers issues beyond the environmental assessment. Therefore, the Board is of the view that these issues need not be added to the scope of the environmental assessment.

With respect to items in the third category, the Board notes that the Canaport[TM] LNG facility has already undergone an environmental assessment by federal authorities under the CEA Act and by the Province of New Brunswick under provincial environmental assessment regulations. Since the LNG facility has already been the subject of a recent environmental assessment, the Board is of the view it should not include the Canaport[TM] LNG terminal or the LNG tanker activity in the scope of the project for the environmental assessment of the Brunswick Pipeline Project. To do otherwise would be contrary to one of the CEA Act's stated purposes, that being the elimination of unnecessary duplication in the environmental assessment process. In addition, assessment of a project under the CEA Act is to occur at the proposal stage. The LNG terminal was assessed at the proposal stage and is now under construction.

However, within the scope of the assessment for the Brunswick Pipeline Project set out in the draft document, the terminal and tanker traffic can still be considered to the extent that they are relevant as cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out.

Some commenters requested that a complete assessment of an underwater route for the Project be included as part of the scope of the environmental assessment. Consideration of alternative means is already a factor within the scope of the environmental assessment and includes consideration of alternative routes and how or why they are technically, economically and environmentally feasible. Accordingly, there is no need to add additional wording to the scope. Intervenors will have an opportunity to test the adequacy of the Applicant's analysis during the hearing and, if they choose, to submit their own evidence.

A comment was received by the Board requesting that in the scope of the environmental assessment, the word "consideration" be removed when referring to factors under paragraph 16(1)(e) of the CEA Act. The Board notes that the word "considered" is used in that paragraph of the CEA Act. Section 16 of the CEA Act requires that the factors listed in that section must be taken into consideration. This is a legislated requirement, therefore the responsible authorities will take these factors into account in the environmental assessment.

The Board has therefore determined that the scope of the Environmental Assessment as outlined in the draft Environmental Assessment Scoping Document is appropriate. The Environmental Assessment Scoping Document has been modified to reflect minor changes in the description of the components listed under the Scope of the Project to accurately reflect the Project as proposed by Emera Brunswick Pipeline Company Ltd. in its application to the NEB. The revised Environmental Assessment Scoping Document is attached.

Purpose of the Scoping Document

This scoping document is an information document briefly describing the scope of the federal and provincial environmental assessments for the Project. The term "scope of the environmental assessment" means the proposed scope of the Project for the purposes of the environmental assessment, the factors proposed to be considered in the environmental assessment, and the proposed scope of those factors.

The responsible authorities (RAs) will ensure that an environmental assessment of the Project is conducted in accordance with the scope of the Project. The RAs will include in their review consideration of the factors identified and will consider the potential effects of the proposed Project within spatial and temporal boundaries described under scope of the factors.

Environmental Assessment Process

The Project has been referred to a Review Panel pursuant to section 25 of the CEA Act. The CEA Act Panel Review requirements will be substituted with the NEB regulatory process as allowed under section 43 of the CEA Act.

The NEB, the Department of Fisheries and Oceans, Transport Canada, Environment Canada and the Canadian Transportation Agency are the RAs and shall ensure that an environmental assessment of the Project is undertaken. The federal permits and authorizations which trigger the CEA Act and will be necessary for this project are:

* a certificate of public convenience and necessity issued pursuant to section 52 of the *National Energy Board Act* (NEB Act);
* authorization by the Minister of Fisheries and Oceans pursuant to subsection 35(2) and/or section 32 of the *Fisheries Act*;
* approval by the Minister of Transport pursuant to subsection 5(1) of the *Navigable Waters Protection Act*;
* possible approval by the Minister of the Environment for disposal at sea pursuant to the *Canadian Environmental Protection Act*; and
* the Canadian Transportation Agency may issue a permit or license under subsection 101(3) of the *Canada Transportation Act.*

To assist in the environmental assessment process, Natural Resources Canada and Health Canada may provide expert advice in relation to the Project.

The Project must be registered as an undertaking pursuant to the New Brunswick *Environmental Impact Assessment Regulation* under the New Brunswick *Clean Environment Act*. The New Brunswick Department of Environment and Local Government administers this regulation and will require that an environmental impact assessment be carried out and approved by Government of New Brunswick before the Project can proceed.

Electronic Filing

While the Board accepted some comments on the draft scope received by e-mail, the Board reminds anyone wishing to participate in the hearing process for the Brunswick Pipeline Project that e-mail will not be accepted during the hearing process. For details on acceptable methods of filing documents, please refer to the NEB's Hearing Order GH-1-2006.

Brunswick Pipeline Project

Environmental Assessment Scoping Document

1.0 INTRODUCTION

The proposed Brunswick Pipeline Project (the Project) is aimed at the construction of a natural gas transmission pipeline from the Canaport[TM] Liquefied Natural Gas (LNG) Facility at Mispec Point, near Saint John, New Brunswick (currently under construction), to an export point at the Canada-US border.

The Project is subject to the federal environmental assessment process pursuant to the *Canadian*

Environmental Assessment Act (the CEA Act).

2.0 SCOPE OF THE ASSESSMENT

2.1 Scope of the Project

The scope of the Project as determined for the purposes of the environmental assessment includes the various components of the Project as described by Emera Brunswick Pipeline Company Ltd. in its application to the National Energy Board dated 23 May 2006, and the physical works and activities described in this document.

The scope of the Project includes construction, operation, maintenance and foreseeable changes, and where relevant, the abandonment, decommissioning and rehabilitation of sites relating to the entire Project, and specifically, the following physical works and activities:

* a pipeline of approximately 145 kilometres from the Canaport[TM] LNG Facility at Mispec Point, near Saint John, New Brunswick (currently under construction) and the international border near St. Stephen, New Brunswick, with a diameter of 762 millimetres (30 inches) and a maximum pressure of 9930 kPa (1440 psi);
* six above-ground valve sites, three in urban Saint John and three in rural areas, within fenced areas approximately 20 metres by 20 metres, with associated access roads, power supply and telecommunications supply;
* a combined meter station and launcher site immediately outside of the Canaport[TM] LNG facility battery limits, with associated access road, power supply and telecommunications supply;
* a combined valve and launcher/receiver station site adjacent to LV 63 on the existing Saint John Lateral (off of the West Branch Road, Musquash), with associated access road, power supply and telecommunications supply; and;
* related physical works and activities, including all temporary facilities, such as temporary work areas, marshalling yards, storage areas and access roads, required for the construction of the pipeline.

2.2 Factors to be Considered

The environmental assessment will include a consideration of the following factors listed in paragraphs 16(1)(a) to (d) and subsection 16(2) of the CEA Act:

1. the environmental effects of the Project, including the environmental effects of malfunctions or accidents that may occur in connection with the Project and any cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out;
2. the significance of the effects referred to in paragraph 1;
3. comments from the public that are received during the public review;
4. measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project;
5. the purpose of the Project;
6. alternative means of carrying out the project that are technically and economically feasible and the environmental effects of any such alternative means;
7. the need for, and the requirements of, any follow up program in respect of the Project; and
8. the capacity of renewable resources that are likely to be significantly affected by the project to meet the needs of the present and those of the future.

In addressing the above factors, which are mandatory in any panel review under the CEA Act, the environmental assessment will demonstrate the following:

* consideration of alternative means includes addressing an alternative marine route for the pipeline south of Saint John that may necessitate a disposal at sea permit;
* a priority on impact avoidance and minimization opportunities that recognizes "... mitigation is used to address all adverse environmental effects, whether or not subsequent analysis determines that the effects are significant" (CEA Agency RA Guide, 1994, p. 88); and,
* a consideration of available community knowledge and Aboriginal traditional knowledge as applicable.

In accordance with paragraph 16(1)(e) of the CEA Act, the assessment by the RAs will also include a consideration of the additional following matters:

9. the need for the Project; and
10. alternatives to the Project.[54]

Subsection 2(1) of the CEA Act defines environmental effects as any change that the Project may cause in the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species, as those terms are defined in subsection 2(1) of the *Species at Risk Act*, any effect of any such change on health and socio-economic conditions, physical and cultural heritage, the current use of lands and resources for traditional purposes by aboriginal persons or any structure site or thing that is of historical, archaeological, paleontological or architectural significance or any change to the Project that may be caused by the environment.

2.3 Scope of Factors to be Considered

The environmental assessment will consider the potential effects of the proposed Project within spatial and temporal boundaries which encompass the periods and areas during and within which the Project may potentially interact with, and have an effect on components of the environment. These boundaries will vary with the issues and factors considered, and will include;

* construction, operation, decommissioning, site rehabilitation and abandonment or other undertakings that are proposed by the Proponent or that are likely to be carried out in relation to the physical works proposed by the Proponent, including mitigation and habitat replacement measures;
* the natural variation of a population or ecological component;
* the timing of sensitive life cycle phases of wildlife species in relation to the scheduling of the Project;
* the time required for an effect to become evident;
* the time required for a population or ecological component to recover from an effect and return to a pre-effect condition, including the estimated degree of recovery;
* the area affected by the Project; and
* the area within which a population or ecological component functions and within which a Project effect may be felt.

For the purpose of the assessment of the cumulative environmental effects, the consideration of other projects or activities that have been or will be carried out will include those for which formal plans or applications have been made.

APPENDIX 5: Board Ruling on Questioning about Alternatives to the Project (17 November 2006, Transcript Volume 11, lines 17126-17136)]

The Board has heard a line of questioning from Anadarko and an objection to the proposed line of questioning by Emera and Repsol.

In responding to these objections, the Board is of the view it would also be helpful for parties to set out a framework for consideration of relevant issues in this proceeding.

The Board is here to hear evidence concerning the benefits and burdens of the applied-for Brunswick Pipeline Project, as currently framed. As a result, exploration of these benefits and burdens of this project by parties to this proceeding is permitted.

Areas such as the impact this project may have on current pipelines, other current or reasonably contemplated projects, current tolls or supply and demand market issues are, therefore, open to be explored.

Need for the pipeline can be fully explored, including the issue of whether this project, as currently framed, could be considered a bypass to existing or reasonably contemplated pipeline facilities.

However, exploration of the benefits or burdens of a project, which is not before the Board, is outside the scope of this proceeding; that is, what the benefits would be of a different project, built by a different company, involving altering of the M&NP Canada System to transfer the supply from Canaport, the cost for doing so and the benefits or burdens of such other project on other matters, such as the ability of Nova Scotia's future potential supply sources to access the market, are outside the scope of this proceeding.

The speculative impact on the levels of tolls, on M&NP Canada, if such a project were to be constructed are also not of probative value to the Board, in assessing the benefits and burdens of this Brunswick Pipeline Project.

There is no evidence submitted that any such speculative or hypothetical project would be constructed.[55] Spending time exploring these speculative and remote alternative projects is not of sufficient probative value to the Board, in determining whether this project is in the present and future of public convenience and necessity.

Alternatives to the project raised, in the context of CEAA, should not be used to delve into a detailed economic analysis of the benefits and burdens of that alternative, as it is outside of the scope of the Board's considerations under CEAA.

Accordingly, a discussion of whether an alternative or hypothetical project, which is not proposed before the Board, and how that hypothetical project could potentially serve incremental natural gas supply for the region, or affect future tolls on other pipelines is not sufficiently tied to an assessment of the benefits and burdens of the Brunswick Pipeline Project, and will not be permitted.

With this direction, Mr. Roth, you may ask any further questions that fall within this framework.

APPENDIX 6: Board Ruling on Questioning about Alternative Means (16 November 2006, Transcript Volume 10, lines 14866-14878)

Yesterday, Mr. Sauerteig asked the Board to consider and allow him to continue cross-examining Emera's Panel No. 1 about his counter-proposal to the marine route that Emera examined in the course of making its decision to apply for the preferred route in its application.

The grounds Mr. Sauerteig relies on to bring this motion are that this marine crossing was an important part of his written intervention and that he has not been afforded sufficient opportunity to test the evidence adduced by Emera regarding the marine route alternatives.

Mr. Sauerteig also argued that no objections to this line of investigating Emera's application to the National Energy Board were raised before November 13, 2006.

Mr. Sauerteig further argued that according to Item 1.8.6 of Emera's application to the NEB, this marine crossing was considered but rejected for reasons which Mr. Sauerteig intended to show in the course of his cross-examination were either wrong or overstated.

Mr. Sauerteig states that this makes this aspect of Emera's application to the NEB suspect and that he was, until his questioning was halted, in the process of disproving most, if not all, of Emera's reasons listed in his application for rejecting this marine crossing.

As the Board has set out in previous applications for review during this hearing, Rule No. 44 of the NEB Rules of Practice and Procedure, requires that an application for review of a Board decision identifies sufficient grounds to raise doubt as to the correctness of that decision or order, including an error of law or jurisdiction, changed circumstances or new facts which have arisen, or facts that were not placed in evidence in the original decision, and were then not discoverable by due diligence.

The Board has not persuaded that grounds have been identified to raise doubt as to the correctness of the Board's request to have Mr. Sauerteig move on to another line of questioning.

As a result, Mr. Sauerteig's application for review is denied.

While the Board could end the matter here and -- will take this opportunity to explain that it is incumbent upon a project proponent to demonstrate under the Canadian Environmental Assessment Act that the proponent has considered alternative means of carrying out its proposed project that are technically and economically feasible.

The Board has throughout these proceedings permitted cross-examination within the scope set out under CEA. In this instance, Emera has filed evidence that it has considered the marine route as an alternative means to the preferred corridor for which it now applies.

It is the appropriateness of the preferred corridor that Emera asks the Board to adjudicate, not the alternative means such as the marine route.

In deciding whether to grant or deny Emera's application, the Board must be satisfied with Emera's evaluation of alternative means, as set out in the Canadian Environmental Assessment Act. Should the Board be satisfied with Emera's evaluation of alternative means under that act, the Board is then only able to judge the appropriateness of the preferred corridor, as applied for by Emera.

The Board points out that in the argument phase of this hearing, parties are free to argue about the adequacy of the alternative means Emera has considered under the Canadian Environmental Assessment Act, including the technical and economic feasibility of those alternative means, and that parties can also argue the adequacy of the preferred route and the general land requirements as set out in the list of issues.

APPENDIX 7: Board Ruling on Objections to Late Filings, Filing of Late Letters of Comment and Requests to File Late Evidence, Ruling Number 10 (Letter dated 23 October 2006)

Background

The Board has received an objection to the Letter of Comment from Ms. L. McColgan, filed with the Board on 10 October 2006. A number of objections were also raised to the request to make an oral statement by Atlantic Institute for Market Studies (AIMS), whose request was filed 6 October 2006. The Board has also received Letters of Comment from Wallace MacMurray, on 13 October 2006, D.R. McColgan and David Hayward, filed with the Board on 17 October 2006. No objections have been received to the filing of these late Letters of Comment. All of these filings were made past the deadlines set out in the Hearing Order GH-1-2006 Timetable of Events, as amended.

The Board has also received two requests for permission to file late evidence from Ms. J. Dingwell, dated 11 October 2006, and from Mr. D. Robichaud, dated 13 October 2006. Furthermore, on 19 October 2006, Mr. Robichaud filed evidence in the form of a report by Accufacts.

In addition, Ms. D. Fuller provided photographs to Board staff on 12 October 2006. The photographs were not accompanied by a request to the Board for permission to file them late.

This ruling deals with all of these matters.

Views of the Board

Criteria that may be considered

The Board is of the view that it would be helpful for all parties to be reminded of the criteria the Board may consider in determining whether to grant requests to file late evidence, late Letters of Comment or late requests to participate.

On any motion for the filing of late evidence, the Board considers whether the applicant for the relief has persuaded the Board that:

(i) the evidence is relevant;
(ii) that there is a justification for filing late or that the party has acted with due diligence to try to meet the deadline; and
(iii) that there will be little prejudice resulting to any party if the evidence is accepted into the record (taking into account any mitigative measures).
(iv) In addition, the Board may consider other factors, such as whether the probative value of the evidence outweighs any prejudice to other parties as a result of the lateness of receiving it; the efficiency and fairness of the Board's regulatory process and the mandate of the Board to make a fully informed decision on an application before it.

In other words, the Board considers whether the applicant for the late participation has provided a justification for what interest the person has in the application before the Board, why it is applying late, and whether any other party would be prejudiced by its participation.

When considering late Letters of Comment or late requests to participate, similar criteria are taken into account. In the case of late participation, the Board may also consider other factors, including whether the participant is likely to materially assist in the understanding of the issues raised by the application, and whether those who already are participating are able to sufficiently advance concerns relating to the public interest. The Board will also balance accommodation of views of those with an interest in the application and the need for an efficient regulatory process.

Turning now to the individual objections, late Letters of Comment and requests to file late evidence, and considering the criteria set out above, the Board finds as follows.

Ms. McColgan's Late Letter of Comment

Letters of Comment often contain both unsworn evidence and aspects of final argument. With respect to Ms. McColgan's late Letter of Comment, the Board notes that while the content of the letter may be relevant to the issues before the Board in this hearing, Ms. McColgan has not provided a justification for filing the Letter of Comment past the deadline (12 September 2006) nor provided any explanation as to why the letter could not have been provided within the timeframe set out in the Hearing Order, In addition no explanation has been given as to why the parties to the hearing will not be prejudiced by the late filing. The Board also notes that a letter of objection to this late request has been filed in these proceedings.

For these reasons, the Board has decided not to admit Ms. McColgan's Letter of Comment onto the record in this proceeding.

Mssrs. MacMurray, McColgan and Hayward's Late Letters of Comment

As permitted by the *National Energy Board Act*,[56] the Board has decided, on its own motion, to deal with the question of whether or not to admit late Letters of Comment filed by Mr. MacMurray, Mr. McColgan and Mr. Hayward. These Letters of Comment have been sent to the Board well past the deadline for filing Letters of Comment, as set out in the Hearing Order. As with Ms. McColgan's letter, none of these submissions provide a justification for filing them past the Board's deadline for filing such letters. Nor do they provide an explanation as to why parties to the hearing will not be prejudiced by the late filings.

For these reasons, the Board has decided not to admit the late Letters of Comment by Mr. MacMurray, Mr. McColgan and Mr. Hayward onto the record in this proceeding.

AIMS' Request to Make an Oral Statement

On 6 October 2006, AIMS submitted its request to make an oral statement. The request does not indicate the position AIMS will take at the oral hearing nor was it accompanied by a Letter of Comment. The request does not indicate why AIMS could not have filed its request by the deadline set out in the Timetable of Events, as amended. A number of parties objected to this late request of the basis that it was not submitted by the required deadline.

As noted in the Hearing Order, persons who make oral statements may not file anything in writing at the time of making their oral statements. Oral statement makers do not receive the application, are not entitled to ask information requests or cross-examine parties to the proceeding, or provide final argument. Oral statement makers are sworn in, make their oral statement, and then are available to be questioned on the statement by the Applicant and the Board and any other party with leave of the Board. As a general rule, only parties adverse in interest may seek leave to question oral statement makers.

The Board notes that the content of the oral evidence and argument to be provided by any oral statement maker is not known by any other party to this proceeding or other oral statement makers prior to the oral portion of the hearing, unless that person has accompanied their request with a Letter of Comment. While the content of the information is not known ahead of an oral statement being made, any prejudice suffered by a party as a result of the content of an oral statement can be rectified by questioning the oral statement maker by the party alleging prejudice.

In this instance, AIMS has not submitted its request within the timelines set out in the Hearing Order nor justified why a late filing should be accepted. Furthermore, AIMS has provided no explanation as to why parties would not be prejudiced by the late filing. While the Board notes that parties adverse in interest could be permitted to question AIMS on its oral statement, in this instance, the Board is not persuaded that, given the late date, AIMS should be permitted to make an oral statement at the hearing.

For these reasons, the Board has decided that AIMS shall not be permitted to present an oral statement at the oral hearing.

Ms. Dingwell's Request to File Late Responses to Information Requests

Ms. Dingwell has requested permission to file her responses to the information requests of Ms. Debly after the deadline set out in the Board's Ruling Number 9. She has indicated in her request that while she has gathered the information, she is awaiting verification by the Cherry Brook Zoo's director prior to submitting it, so as to ensure its accuracy. The Board has previously indicated that this information may be relevant to the issues before the Board and the resolution of those issues. The late information sought by the information request is of a factual nature; that is, it concerns facts related to the zoo's background. In the Board's view this type of information is not likely to create significant prejudice to other parties adverse in interest, particularly if the information is submitted prior to the commencement of the oral hearing. As an intervenor who has filed written evidence, Ms. Dingwell may be subject to cross-examination on this evidence by parties who are adverse in interest to her.

The Board is of the view that Ms. Dingwell's request should be granted. Ms. Dingwell is required to file this evidence with the Board and serve a copy on all parties prior to the commencement of the oral hearing.

Ms. Fuller's Photographs

During the pre-hearing planning conference held in November in New Brunswick, Ms. Fuller passed some photographs to a member of the Board's staff. Despite being advised of the procedure for filing late evidence, the photographs were not accompanied by a letter seeking permission to file the photographs late, or an explanation as to why these photographs could not have been filed in a timely manner. No explanation as to the relevance of these photographs to the issues before the Board was provided.

While in New Brunswick, the Board visited a number of locations suggested by parties to better their understanding of the evidence submitted. The majority of the locations in these photographs were visited by the Board. The Board is of the view that the probative value of these photographs does not outweigh the prejudice of introducing late intervenor evidence at this time in the proceeding. Accordingly, the photographs will not form part of the record in this proceeding and will be returned to Ms. Fuller.

Mr. Robichaud's Request to File Late Evidence

Mr. Robichaud has indicated in his 13 October 2006 letter that he was unable to find a specialist to complete a report for him until early in October. No report was attached to that letter, nor was a description of the subject matter or content, the name of the author or any other details related to the report. However, on 19 October 2006, Mr. Robichaud submitted, to the Board, a report by Accufacts entitled "*Commentary on the Risk Analysis For the Proposed Emera Brunswick Pipeline Through Saint John, NB*".

The Board has before it Mr. Robichaud's explanation of why he was not able to file the report earlier. It also has before it the report itself. However, before ruling on the admission of the report as late intervenor evidence, the Board has decided that it would like to hear comments from the Applicant, Emera Brunswick Pipeline Company (EBPC), regarding the admission of this report onto the record as late intervenor evidence.

Accordingly, EBPC is directed to file comments, if any, with the Board and serve a copy on Mr. Robichaud by no later that **5:00 p.m. Calgary time, on Tuesday 24 October 2006**.

Mr. Robichaud is directed to file a response, if any, with the Board and serve a copy on EBPC and its counsel by no later that **5:00 p.m. Calgary time, on Thursday 26 October 2006**.

APPENDIX 8: Board Ruling on Dr. Thomas's Request to Revisit the Scope of the Project (9 November 2006, Transcript Volume 4, lines 5409-5427)

Dr. Thomas seeks to revisit the scope of the Brunswick Pipeline project to include the Canaport LNG Terminal in concert with the proposed Brunswick Pipeline to form one project as a whole to be considered under CEAA.

Emera's counsel, Mr. Smith objects on the basis that the Board in its capacity as a responsible authority under the Canadian Environmental Assessment Act has already determined with other responsible authorities the scope of the Brunswick Pipeline and the cumulative effects that can be considered.

On June 23rd, 2006, Exhibit A-3, the Board determined the scope of the Brunswick Pipeline project. On that date the Board also set out that cumulative effects including the Canaport LNG Terminal and tanker traffic could still be considered to the extent that those effects are relevant as cumulative effects that are likely the result from the project in combination with other projects or activities that have been or will be carried out.

In a subsequent ruling addressing an outstanding information request dated the 21st of September, 2006 Exhibit A-27 the Board set out the process for cumulative environmental effects assessment. The Board takes this opportunity to reiterate how this process works. The approach to accumulative effects assessment reflected in Guide A, Section A.2.6 of the National Energy Board's filing manual is to undertake the following sequential steps.

One, identify the potential effects for which residual effects are predicted for the project being assessed. Residual effects are those which would still exist after any mitigation is applied.

Two, for each biophysical element where residual effects are identified, determine the spatial and temporal boundaries that will be used to assess the potential cumulative effects.

Three, identify other projects and activities that have occurred or are likely to occur within the residual effects boundaries. And identify whether those projects and activities will produce effects on the biophysical element within the identified boundaries.

Four, consider whether the effects in three as just identified act in combination with the project's residual effects and if so include those projects or activities in the cumulative effects assessments.

And then five, analyze the cumulative effects of the proposed project in combination with other projects and activities for each biophysical element.

This includes considering the residual effects of the proposed project in combination with the effects of other projects and activities and considering whether the proposed project is incrementally responsible for adversely affecting a biophysical element beyond an acceptable point, for example threshold.

The manual also states that the level of effort and scale of the cumulative environmental effects assessment should be appropriate to the nature of the project under assessment, its potential residual effects and the environmental in socioeconomic setting.

The Board also wishes to emphasize that one of the purposes of the Canadian Environmental Assessment Act as set out in paragraph 4(1)(b.1) is to ensure that responsible authorities carry out their responsibilities in a coordinated manner with a view to eliminating unnecessary duplication in the environmental assessment process.

As noted in the Board's June 23rd, 2006 letter the Canaport LNG Terminal including the LNG tanker traffic has already undergone an environmental assessment by Federal authorities under the CEAA Act and by provincial authorities. That assessment is publicly available on CEAA's online registry. Therefore in carrying out its cumulative environmental effects assessment of the Brunswick Pipeline the Board must ensure that it is not being duplicative of environmental assessment processes already undertaken.

And that it is the potential residual effects of the Brunswick Pipeline being assessed. The Board's consideration of other projects is only in the context of whether those other projects have effects that have the potential to act in combination with the Brunswick Pipeline's residual effects.

Further the nature of the Brunswick Pipeline project and its potential residual effects also inform the level of effort and scale of the cumulative effects assessment.

It is within this context that the Board can consider LNG Terminal or LNG tanker traffic to the extent that they act in combination with any residual effects of the Brunswick Pipeline.

The Board is of the view that Dr. Thomas' line of question does not fall within this context. Furthermore, Dr. Thomas' concern with respect to the EIS completed for the LNG Terminal cannot be addressed in this proceeding. The Board was not an RA for that project.

In addition the Board reiterates its comments on the scoping document that assessment of a project under the CEAA Act is to occur at the proposal stage. The environmental assessment for that facility has been completed. This is not the appropriate forum for Dr. Thomas to challenge the adequacy of the LNG Terminal EIS.

As a result the Board upholds Mr. Smith's objection to Dr. Thomas' questioning and we will hear from Mr. Court again beginning tomorrow at 9:00 a.m.

APPENDIX 9: Board Ruling on Ms. T. Debly's Notice of Motion to Require EBPC to Respond to Information Requests (IRs), Ruling Number 7 (Letter dated 21 September 2006)

On 7 September 2006, Ms. Debly filed a Notice of Motion to require EBPC to respond to certain IRs submitted by her and by the Estate of A.J. Debly. In addition, she requested an extension to the deadline for filing her evidence until 15 days after EBPC responded to these IRs. The Board sought comments from EBPC and Ms. Debly before making its determination, and received comments from EBPC dated 13 September 2006 and from Ms. Debly dated 18 September 2006.

Criteria for Responding to Information Requests

Before coming to the views of the Board with respect to the motion, it may be helpful to set the information request process into the context of the Board's overall role as a decision-maker.

While the Board is not formally bound by the rules of evidence, it may not take into account facts that have no logical connection to the decision it has to make, nor fail to take into account relevant and material facts. Relevant facts are provided in a number of ways, including through the application, through evidence filed in support of the application, and through responses to information requests posed by the Board or by parties to a proceeding, or through evidence filed by other parties to the proceeding.

Sections 32 to 34 of the *National Energy Board Rules of Practice and Procedure, 1995* (the Rules) deal specifically with the information request process. These rules provide that in response to an information request, a party must provide one of the following: a full and adequate response to the information request; a statement setting out the objection to responding and the grounds therefore; or a statement that the information is not available, setting out the reasons for the unavailability and the alternative available information that may be of assistance.

With respect to the general purpose of information requests and the criteria used to decide when an applicant will be directed to respond to a request, the Board has previously stated:

> The Board process allows for the use of written information requests for a number of reasons. Applications before the Board require the consideration of substantial information, much of it of a detailed and technical nature. Often this information is not conducive to an examination by the oral cross-examination process. Parties are therefore encouraged to obtain and examine such information through the established information request process. This process can be used to obtain the evidence necessary to test and explore the Applicant's case and, in the case of Intervenors, to assist them in preparing their cases.
>
> ... When the parties cannot agree on the appropriateness of the Information Request or the adequacy of a Response, the Board is asked to provide direction. When considering such a motion, the Board looks at the relevance of the information sought, its significance and the reasonableness of the request. It seeks to balance these factors to ensure that the purposes of the Information Request process are satisfied, while ensuring that an Intervenor does not engage in a "fishing expedition" that could unfairly burden the Applicant.[57]

The criteria of relevance, significance and reasonableness have been applied in a number of proceedings before the Board.[58]

In determining whether the information sought to be elicited through the information request process in this proceeding should be provided, the Board is of the view that a similar analysis should be undertaken; looking at whether the information requested is relevant, whether it is significant (or probative) and whether the request is reasonable, and balancing these factors to ensure that the purpose of the information request process has been satisfied.

Cumulative Environmental Effects Assessment

In addition to the criteria set out above, as the IRs are raised in the context of the Board's letter on the Environmental Assessment Scoping Document, dated 23 June 2006, some discussion of how cumulative effects assessments are carried out in the Board's process is useful. The approach to cumulative effects assessment reflected in Guide A, Section A.2.6 of the National Energy Board's Filing Manual (the Manual) is to undertake the following sequential steps:

Identify the potential effects for which residual effects are predicted for the project being assessed (residual effects are those which would still exist after any mitigation is applied);

For each biophysical element where residual effects are identified, determine the spatial and temporal boundaries that will be used to assess the potential cumulative effects;

Identify other projects and activities that have occurred or are likely to occur within the residual effects boundaries and identify whether those projects and activities will produce effects on the biophysical element within the identified boundaries;

Consider whether the effects in (3) act in combination with the project's residual effects and if so, include those projects or activities in the cumulative effects assessment; and then

Analyze the cumulative effects of the proposed project in combination with other projects and activities for each biophysical element; this includes considering the residual effects of the proposed project in combination with the effects of other projects and activities and considering whether the proposed project is incrementally responsible for adversely affecting a biophysical element beyond an acceptable point (*i.e.,* threshold).

The Manual also states that "The level of effort and scale of the cumulative environmental effects assessment should be appropriate to the nature of the project under assessment; its potential residual effects; and the environmental and socio-economic setting."

The Board also wishes to emphasize that one of the purposes of the *Canadian Environmental Assessment Act* (CEA Act), as set out in paragraph 4(1)(b.1), is "to ensure that responsible authorities carry out their responsibilities in a coordinated manner with a view to eliminating unnecessary duplication in the environmental assessment process." As noted in the Board's 23 June 2006 letter, the Canaport[TM] LNG facility, including its environmental effects on air quality, has already undergone an environmental assessment by federal authorities under the CEA Act and by provincial authorities. That assessment is publicly available on the Canadian Environmental Assessment Agency's online registry.

Therefore, in carrying out its cumulative environmental effects assessment of the Brunswick Pipeline, the Board must ensure it is not being duplicative of environmental assessment processes already undertaken; and that it is the potential residual effects of the Brunswick Pipeline that are being assessed. The Board's consideration of other projects is only in the context of whether those other projects have effects that have the potential to act *in combination* with the Brunswick Pipeline's residual effects. Further, the nature of the Brunswick Pipeline project and its potential residual effects also inform the level of effort and scale of the cumulative effects assessment. It is within this context that the Board can consider terminal or tanker traffic *to the extent that they are relevant* as cumulative environmental effects that are likely to result for the Brunswick Pipeline in combination with other projects or activities that have been or will be carried out.

Specific Information Requests

IR EOD 1.3

The Board is of the view that IR EOD 1.3 from the Estate of A.J. Debly has been sufficiently responded to by EBPC in its responses. Accordingly, the Board will not direct EBPC to further respond to this IR.

IRs TD 1S.12, TD 1S.13, TD 1S.17 and TD 1S.18

Based on the context noted in the previous section, and balancing the three criteria of relevance, significance and reasonableness set out above, the Board is of the view that these IRs seek information that does not appear to be sufficiently significant or probative to the Board's assessment of the cumulative effects of the Brunswick Pipeline to require EBPC to undertake a further response to these IRs.

However, the Board notes that Ms. Debly and the Estate of A.J. Debly may submit, as part of their own evidence, any evidence they feel is relevant to the cumulative environmental effects assessment and the Brunswick Pipeline's impact on air quality.

IRs TD 1S.15, TD 1S.16, and TD1S.20 to 1S.22

With respect to IRs 1S.15, 1S.16, and 1S.20 to 1S.22 of Ms. Debly's IRs, the Board is of the view that the information requested is not sufficiently significant or probative to the Board's consideration of EBPC's application to require EBPC to provide a further response to these IRs.

In the Board's view, the information sought appears to relate primarily to the broad issue of global greenhouse gas emissions, and their environmental effects. For example, the environmental effects of upstream LNG production in another country do not have the ability to act cumulatively with the environmental effects of the Brunswick Pipeline except on a global level. A focused and accurate assessment of these environmental effects is not feasible. As noted in the Manual, some spatial and temporal boundaries to the cumulative effects assessment have to be utilized.

In addition, in the Board's view, calculating the emissions of upstream LNG production or determining the end use(s) of gas transported on the Brunswick Pipeline regardless of the site of the LNG production or the end use of the gas would not be helpful to the determination it must make.

Considering these environmental effects would be a difficult exercise of little, if any, probative value. It is too broad, too speculative and of too little utility to be useful for the section 52 determination to be made by this Board. As a result, the Board will not direct EBPC to respond further to IRs 1S.15, 1S.16, and 1S.20 to 1S.22.

Conclusion

For the foregoing reasons, the Board hereby denies Ms. Debly's motion requesting EBPC to further respond to her and the Estate of A.J. Debly's IRs, and for a 15-day extension to Ms. Debly's deadline for filing written evidence.

Appendix VIII

Government Response to the National Energy Board Environmental Assessment Report

GOVERNMENT RESPONSE TO THE RECOMMENDATIONS CONTAINED IN THE REPORT OF THE NEB REVIEW PANEL ON THE BRUNSWICK PIPELINE PROJECT

Emera Brunswick Pipeline Company (EBPC) filed an application with the National Energy Board (NEB) for a Certificate of Public Convenience and Necessity (Certificate) under section 52 of the *National Energy Board Act (NEB Act)* to construct and operate the Brunswick Pipeline Project (the project).

The principal purpose of the project is to connect the Canaport Liquefied Natural Gas (LNG) terminal (currently under construction at Mispec Point, New Brunswick) to the U.S. portion of the Maritimes and Northeast Pipeline (MNP) at the international border near St. Stephen, New Brunswick.

The project will consist of approximately 145 km of 30-inch pipeline. The pipeline will serve markets in the U.S. northeast and provide for additional supplies of natural gas in New Brunswick and Nova Scotia through arrangements such as swaps or back-haul transportation service.

The need for a Certificate under section 52 of the *NEB Act* resulted in the requirement for an environmental assessment (EA) of the project pursuant to paragraph 5(2)(a) of the *Canadian Environmental Assessment Act* (*CEA Act*). Other requirements include subsection 35(2) *Fisheries Act* authorizations from the Minister of Fisheries and Oceans, approvals under the *Navigable Waters Protection Act* from the Minister of Transport Canada, and a Disposal at Sea permit under the *Canadian Environmental Protection Act* (1999), from the Minister of the Environment.

The need for any such authorizations, approvals or permits under the *Fisheries Act*, the *Navigable Waters Protection Act*, and the *Canadian Environmental Protection Act,* 1999, also results in the requirement for an environmental assessment pursuant to paragraph 5(1)(d) of the *CEA Act*.

On May 4, 2006, the Minister of the Environment referred the Brunswick Pipeline Project to a substituted NEB Review Panel. The NEB process was substituted for an EA by a review panel as provided for under section 43 of the *CEA Act*. This was the first application of the substitution provisions of the *CEA Act* since the proclamation of the original Act in 1995. The substitution was approved on a pilot basis.

The panel conducted a review of the environmental effects of the project in accordance with the requirements of the *CEA Act*. The panel also assessed the requirements of the *NEB Act*. This includes an assessment of the technical, safety and economic aspects of the project.

The panel released its report on April 11, 2007, concluding that the project is not likely to result in significant adverse environmental effects provided the panel's recommendations are implemented and appropriate mitigation measures identified during the course of the review is applied. The panel recommended that the project be allowed to proceed to regulatory and departmental decision-making as long as the recommendations in its report are made part of the requirements of any approval by the NEB.

Pursuant to subsection 37(1.1) of the *CEA Act*, Responsible Authorities (RAs) shall take into consideration the panel's report and, with the approval of the Governor-in-Council, respond to it. The purpose of this government response is to fulfill this requirement.

All recommendations have been accepted within the context of the Government of Canada mandate. Federal departments are committed to working with the NEB and the Province of New Brunswick in implementing the recommendations based on jurisdictional responsibilities. It is understood that EBPC will develop the necessary plans, and other mitigation measures and follow-up programs identified in the recommendations, in consultation with those expert federal departments with a mandated responsibility and interest.

Following the approval of this response, the panel will decide whether to issue a Certificate under the *NEB Act*. The issuance of a Certificate under section 52 of the *NEB Act* will be subject to Governor-in-Council approval.

RECOMMENDATIONS IN THE REVIEW PANEL REPORT

It is recommended that in any Certificate that the NEB may issue, the following recommendations be attached as conditions of approval.

Recommendation A: General

EBPC shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included or referred to in its application or as otherwise agreed to during questioning or in its related submission.

Response A

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation B: Environmental Protection Plan

EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a project-specific Environmental Protection Plan (EPP). This EPP shall be a comprehensive compilation of all environmental protection procedures, mitigation measures, and monitoring commitments, as set out in EBPC's application for the project, subsequent filings, evidence collected during the hearing process, or as otherwise agreed to during questioning or in its related submissions. The EPP shall describe the criteria for the implementation of all procedures and measures, and shall use clear and unambiguous language that confirms EBPC's intention to implement all of its commitments.

Construction shall not commence until EBPC has received approval of its EPP from the Board.

The EPP shall address, but is not limited to, the following elements:

1) environmental procedures including site-specific plans, criteria for implementation of these procedures, mitigation measures and monitoring applicable to all project phases and activities;
2) site-specific construction plans for wetlands where they cannot be avoided;
3) site-specific plans for habitat harbouring Species at Risk and of Conservation Concern where it cannot be avoided;
4) project-specific acid rock drainage mitigation measures;
5) a construction and reclamation plan for Rockwood Park with evidence demonstrating consultation with stakeholders;
6) a reclamation plan which includes a description of the condition to which EBPC intends to reclaim and maintain the right of way once the construction has been completed, and a description of measurable goals for reclamation; and,
7) evidence of consultation with relevant regulatory authorities that either confirms satisfaction with the proposed mitigation or summarizes any unresolved issues with the proposed mitigation.

<u>Response B</u>

The Government of Canada accepts this recommendation with the understanding that the pre-construction field studies and surveys, which inform preparation of the EPP, will be completed by EBPC to the satisfaction of the appropriate federal departments. In considering the field study and survey results, it is further understood that expert federal departments must confirm the adequacy of proposed mitigation and follow-up details including provisions for compliance with Section 79 of the *Species at Risk Act.*

Based on evidence filed at the hearings, the Government of Canada further suggests that the EPP also include, but not be limited to, the following elements:

* **site-specific plans for old-growth, mature and interior forest habitats for migratory birds where such habitats cannot be avoided; and,**
* **provisions for protecting populations or individuals or species at risk, species of conservation concern and migratory birds.**

<u>Recommendation C: Environmental Follow-Up Programs</u>

EBPC shall file with the Board for approval, at least sixty (60) days prior to construction, a description of planned follow-up programs as required by the *Canadian Environmental*

Assessment Act. The programs shall be designed to verify the accuracy of the environmental assessment predictions and to assess the effectiveness of mitigation for:

- fish and fish habitat as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);
- wetlands as outlined in the Brunswick Pipeline Project Environmental and Socio-Economic Assessment (Volume 1);
- access management as detailed in the Access Management Plan (recommendation G);
- horizontal directional drill (HDD) noise management (recommendation I); and,
- reclamation of Rockwood Park (recommendation B(3)).

Copies of all correspondence demonstrating consultation with the appropriate regulatory agencies and stakeholders shall be included in the submission to the Board.

These descriptions of follow-up programs shall include a schedule for the submission of follow-up reports to the Board.

Response C

The Government of Canada accepts this recommendation and further suggests that specific allowance be made to include other valued ecosystem components, such as species at risk, species of conservation concern, and migratory birds, subject to review of completed field studies and surveys and the expert opinion of federal departments.

Based on evidence filed at the hearings, the Government of Canada further suggests that the wetland follow-up program be designed to address effects that may endure beyond EBPC's proposed 5-year monitoring period and that the determination of appropriate compensation for unavoidable losses be established independent of the amount of time required for natural revegetation.

Recommendation D: Traditional Ecological Knowledge Study Recommendations

EBPC shall file with the Board, at least sixty (60) days prior to construction, an update on the implementation of the six recommendations identified in the Traditional Ecological Knowledge Study (July 2006).

Response D

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation E: Construction Inspection Program

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a construction inspection program. The program shall include:

1) a preliminary list of the number and type of each inspection position, including job descriptions, qualifications, roles, responsibilities, and decision-making authority;
2) a discussion of how many changes to the items outlined in (1) would be determined during the course of construction; and,
3) the reporting structure of personnel responsible for inspection of the various pipeline construction activities, including environment and safety.

Response E

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation F: Archaeological Studies and Monitoring Plan

EBPC shall consult with the Archaeological Services Unit of New Brunswick on further studies and a monitoring plan for areas with high potential for heritage resources, once the locations for the detailed right of way, facility sites and temporary work space have been determined. EBPC shall file with the Board, at least thirty (30) days prior to construction:

1) for approval, a report that documents how archaeological and heritage resources within the detailed route have been identified, recorded and mitigated;
2) copies of any correspondence from, or a summary of any discussions with the Archaeological Services Unit of New Brunswick regarding the acceptability of EBPC's report and proposed mitigation measures; and,
3) for approval, a copy of any proposed monitoring plan.

Response F

The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees. This recommendation is under the jurisdiction of the province of New Brunswick.

Recommendation G: Access Management Plan

EBPC shall file with the Board for approval, at least thirty (30) days prior to construction, a project-specific Access Management Plan that includes:

1) EBPC's goals and measurable objectives regarding the Access Management Plan;
2) the methods and procedures to be used to achieve the mitigation goals;
3) the criteria to determine if the mitigation goals have been met;
4) the frequency of monitoring activities along the right of way;
5) a description of the adaptive measures that will take place in the event that access management measures are ineffective; and,

6) evidence of consultation with relevant regulatory authorities and landowners that either confirms satisfaction or summarizes any un-resolved issues with the proposed mitigation.

Construction shall not commence until EBPC has received approval of its Access Management Plan from the Board.

Response G

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

The proponent shall prepare an Access Management Plan in consultation with the appropriate expert federal authorities in a matter consistent with their mandated responsibilities and interests.

Recommendation H: HDD (Horizontal Directional Drilling) Noise Management Plan

EBPC shall file for approval, at least ninety (90) days prior to the start of the HDD activity proposed for the Saint John River Crossing, a detailed noise management plan containing information on day-time and night-time HDD operations at the drill exit and entrance sites, including but not limited to the following:

1) ambient sound levels at noise-sensitive areas close to the HDD exit and entrance sites to establish a baseline for assessing potential noise impacts;
2) predicted noise level at the most affected residences caused by HDD without mitigation;
3) proposed HDD noise mitigation measures, including but not limited to the following:

    i) all technologically and economically feasible mitigative measures as presented in Section 5.1.7 of the Environmental and Socio-Economic Assessment (Jacques Whitford, 2006) and in the Resource Systems Engineering assessment;
    ii) the use of full enclosures on diesel powered units;
    iii) the use of quiet machinery (where feasible);
    iv) the undertaking of HDD activities during periods where residential windows would be expected to be closed (i.e., during winter months);

4) predicted noise level at the most affected residences with implementation of the mitigation measures;
5) noise contour map(s) showing the potentially affected residences at various noise levels;
6) a noise monitoring program, including locations, methodology and schedule;

7) confirmation that residents potentially affected by HDD noise will receive contact information for EBPC in the event they have concerns about the HDD noise;
8) a contingency plan with proposed mitigative measures for addressing noise complaints, which may include the temporary relocation of specific residents; and,
9) confirmation that EBPC will provide notice to nearby residents in the event that a planned blowdown is required and that planned blowdowns will be completed during day-time hours whenever possible.

Response H

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation I: Saint John River Crossing

EBPC shall construct the crossing(s) of the Saint John River using the HDD method or, if this is not feasible, shall apply to the Board for approval of an alternative crossing technique and include an environmental assessment of the proposed alternative with its application.

Response I

The Government of Canada accepts this recommendation. The proponent is further advised that any project change or modification that may require a disposal at sea permit pursuant to the *Canadian Environmental Protection Act,* 1999, will require an environmental assessment under the *Canadian Environmental Assessment Act.*

Recommendation J: Archaeological or Heritage Resource Discovery

EBPC shall notify the Board, at the time of discovery, of any archaeological or heritage resources and, as soon as reasonable thereafter, file with the Board for approval a report on the occurrence and proposed treatment of the archaeological/heritage resources, any changes to the archaeological/heritage monitoring plan, and the results of any consultation, including a discussion on any unresolved issues.

Response J

The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees. This recommendation is under the jurisdiction of the province of New Brunswick.

Recommendation K: Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, an Emergency Procedures Manual (EPM) for the Project and shall notify the Board of any modifications to the plan as they occur. In preparing its EPM, EBPC shall refer to the Board letter dated 24 April 2002 entitled "Security and Emergency Preparedness Programs" addressed to all oil and gas companies under the jurisdiction of the National Energy Board.

Response K

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

The proponent shall prepare an Emergency Procedures Manual in consultation with the appropriate expert federal departments in a manner consistent with their mandated responsibilities and interests.

Recommendation L: Consultation on Emergency Procedures Manual

EBPC shall file with the Board, at least sixty (60) days prior to operation, evidence of consultation with stakeholders identified in the EPM, including a summary of any unresolved issues identified in consultations, and evidence that the EPM addresses, to the extent possible, any issues raised during consultation.

Response L

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

The proponent shall prepare an Emergency Procedures Manual in consultation with the appropriate expert federal authorities in a matter consistent with their mandated responsibilities and interests.

Recommendation M: Emergency Response Exercise

1) Within six (6) months after commencement of operation of the Project, EBPC shall conduct an emergency response exercise with the objectives of testing:

* emergency response procedures;
* training of company personnel;
* communications systems;
* response equipment;
* safety procedures; and,
* effectiveness of its liaison and continuing education programs.

2) EBPC shall notify the Board, at least thirty (30) days prior to the date of the emergency response exercise, of the following:

* the date and location(s) of the exercise;
* the participants in the exercise; and,
* the scenario for the exercise.

3) EBPC shall file with the Board, within sixty (60) days after the emergency response exercise outlined in (1), a report on the exercise including:

* the results of the exercise;

* areas for improvement; and,
* steps to be taken to correct deficiencies.

Response M

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation N: Emergency Response Exercise Program

Within six (6) months after commencement of operation of the Project, EBPC shall file with the Board a description of the company's emergency response exercise program, including:

* the frequency and type of exercises (full-scale, table-top, drill) it plans to conduct; and,
* how the results of any emergency response exercises will be integrated into the company's training and exercise programs.

Response N

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation O: Post-construction Environmental Reports

Within six (6) months following commencement of operation of the Project, and on or before the 31st of January following each of the second (2nd) and fourth (4th) complete growing seasons following commencement of the operation of the Project, EBPC shall file with the Board a post-construction environmental report that:

1) identifies on a map or diagram any environmental issues that arose during construction;
2) provides a discussion of the effectiveness of the mitigation applied during construction;
3) identifies the current status of the issues identified, and whether those issues are resolved or unresolved; and,
4) provides proposed measures and the schedule EBPC shall implement to address any unresolved issues.

Response O

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

Recommendation P: Environmental Follow-Up Program Reports

EBPC shall file with the Board, based on the schedule referred to in Recommendation C, the report(s) outlining the results of the follow-up programs.

Response P

The Government of Canada accepts this recommendation. The NEB has recommended that this become a condition of approval for any certificate it may issue. The Government of Canada agrees.

1 The Board has developed five corporate goals to help it meet the challenges it faces in a dynamic energy market and ever-changing regulatory landscape. The NEB's Goal 4 states as follows: "The NEB fulfills its mandate with the benefit of effective public engagement." Effective public engagement is a key component in making certain that the rights of persons affected by the Board's decisions are protected, as it ensures that the Board has all of the relevant evidence it requires prior to making a decision and, consequently, that the principles of natural justice and fairness are met. As a result, effective public engagement also allows the Board to meet another of its Goals, "NEB-regulated facilities are built and operated in a manner that protects the environment and respects the rights of those affected."

2 As defined in the division of powers between the provinces and the Federal government under sections 91 and 92 of the *Constitution Act, 1867*.

3 Macaulay and Sprague, *Practice and Procedure before Administrative Tribunals*, (Toronto: Carswell, 2001) [hereinafter "Macaulay"], at p. 9-20.1. Essentially, a purely legislative decision would be one which establishes a standard, norm or rule of conduct binding upon an undetermined number of persons, and which may be driven by policy considerations, Macaulay at p. 9-20.4.

4 *Tandy Electronics Ltd.* v. *United Steel Workers of America* (1979), 102 D.L.R. (3d) 126 (Ontario High Court of Justice), per Cory J., at 132.

5 Macaulay at p. 9-20.9 to 9-20.10.

6 *Ibid*, at p. 9-20.8(4).

7 The "public convenience and necessity" test will be discussed further below.

8 For example, in a ruling dated 23 October 2006, the Board set out criteria that it may consider in determining whether to grant requests to file late evidence, late Letters of Comment or late requests to participate [Ruling #10, A-36]. This ruling is included in Appendix VI.

9 See the Board's Internet site at
http://www.neb-one.gc.ca/PublicInterestFootnote-e.htm.

10 See for example, *Re Actus Management Ltd. and City of Calgary* (1975), 62 D.L.R. (3d) 421 (Alta. Sup. Ct. (A.D.)), at QL p.4.

11 Macaulay, *supra* note 3, at p. 8-6.

12 *Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co.,* [1958] S.C.R. 353 at 357 (SCC).

13 *Joint Public Review Panel Report*, Sable Gas Projects, dated October 1997, pp. 129-130, citing *Memorial Gardens*. The Joint Panel Report was considered in the *National Energy Board GH-6-96 Reasons for Decision*, Sable Offshore Energy Project and Maritime and Northeast Pipeline Project, dated December 1997.

14 *National Energy Board GH-3-97 Alliance Comprehensive Study Report*, Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership, dated September 1998, at p. 9.

15 *National Energy Board GH-3-97 Reasons for Decision,* Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership, dated November 1998, at p. 8.

16 *National Energy Board GH-1-98 Reasons for Decision*, Northstar Energy Corporation, dated May 1998, at p. 27.

17 *National Energy Board EH-1-2000 Reasons for Decision*, Sumas Energy 2, Inc., March 2004, at p. 10, citing with approval comments made by the Ontario Energy Board.

18 *National Energy Board GH-2-2000 Reasons for Decision*, AEC Suffield Gas Pipeline Inc., dated August 2000, at p. 22-23.

19 [1974] 2 F.C. 313.

20 *Sumas Energy 2, Inc. v. Canada (National Energy Board),* [2005] F.C.J. No. 1895 (FCA), at QL para. 35.

21 [1945] 3 D.L.R. 417 at 420.

22 Goal 3 of the National Energy Board states "Canadians benefit from efficient energy infrastructure and markets."

23 UNBI is the Aboriginal organization representing the following 12 First Nations in New Brunswick: Madawaska, Woodstock, Kingsclear, St. Mary's, Oromocto, Eel River Bar, Pabineau, Metepenagiag, Eel Ground, Indian Island, Buctouche, and Fort Folly.

24 The MAWIW Council was formed by the Chiefs of the three most populous First Nations in New Brunswick: Big Cove, Burnt Church, and Tobique.

25 Condition 5 in Appendix V to these Reasons.

26 Conditions 2 and 5 in Appendix V to these Reasons.

27 Condition 6 in Appendix V to these Reasons.

28 Conditions 11 and 19 in Appendix V to these Reasons.

29 Westcoast Energy Inc. (GH-5-94), Transcript volume 3 (8 February 1995), at 340-342.

30 For example, the Board's Letter Decision dated 5 September 2002 on Westcoast Energy Inc.'s Southern Mainline Expansion Project (GH-1-2002) and the Board's Letter Decision dated 14 February 2003 on Sumas Energy 2, Inc.'s application for an international power line (EH-1-2000).

31 R.S. 1985, c. N-7.

32 Correction to this word in the original transcript was made in transcript volume 12, paragraph 19686.

33 Significant environmental effects would typically involve environmental effects that are a combination of several of high frequency, irreversible, long term in duration, large in extent, or high magnitude.

34 The definitions of RA and FA are set out in the Glossary.

35 OPS-EPO/2-1998. The Board is of the view that it may help parties to explain how these factors are considered by the Board as an RA under the CEA Act. Such an explanation is provided in sections 3.2 and 3.3 below.

36 In many of the Board's prior major pipeline hearings in which an EA was conducted under the CEA Act, the purpose of and need for the project generally were established from the perspective of the project proponent. See for example, *Report of the Joint Review Panel* OH-1-95, Express Pipeline Project, May 1996 (Express), at 11; *The Joint Public Panel Review Report*, Sable Gas Projects, October 1997 (Sable), at 16, 62-64; *Comprehensive Study Report* GH-3-97, Alliance Pipeline Project, September 1998 (Alliance), at p.8.; and the *Joint Review Panel Report*, GSX Canada Pipeline Project, July 2003 (GSX) at p. 193-205. Although the Board is not bound by its past decisions, these decisions may provide some assistance to parties in determining how the Board has consistently addressed these factors in the past.

37 This is consistent with the Board's prior decisions, for example, see Sable, *supra* note 4 at 87 ff., and Alliance, *supra*, note 4, at 17, as supported by subsequent case law, see *Sharp, infra*, note 7.

38 This is consistent with the Board's prior decisions, see for example, GSX, *supra* note 4, at 15

39 See *Sharp* v. *Canada (Transportation Agency)*, [1999] F.C.J. No. 948 (FCA), in which the Court found that it was within the discretion of the Agency to decide the nature and extent of its consideration of need and alternatives taking into consideration the environmental acceptability of the proposed project. The Court also said that business or commercial needs are a legitimate basis for rejecting alternatives.

40 National Energy Board GH-1-2006, Emera Brunswick Pipeline Company Ltd., Transcripts, 17 November 2006, Vol. 11, paras. 17126-17136; attached as Appendix 5 to this Report.

41 It appears that Anadarko is essentially arguing that the Board is required to consider an expansion of the existing Maritimes and Northeast pipeline and the relative economic costs and toll implications of such an expansion as part of the Board's consideration of *alternatives to* the Brunswick Pipeline project. (Anadarko Final Argument, 15 December 2006, pp. 4-13).

42 Friends of Rockwood Park Final Argument, 15 December 2006, Part 1, p. 4.

43 For example, *Sharp, supra* note 7.

44 See *Sharp, supra*, note 7.

45 *Inverhuron & District Ratepayers' Assn. v. Canada (Minister of the Environment)* [2001] F.C.J. No. 1008 (FCA) at para. 50; application for leave to appeal to SCC dismissed without reasons [2001] S.C.C.A. No. 463.

46 See also *Sable, supra* note 4, at 87; *Alliance, supra*, note 4, at 31; GSX, *supra* note 4, at 21.

47 *Alberta Wilderness Assn. v. Express Pipelines Ltd.,* [1996] F.C.J. No. 1016 (FCA).

48 The assessment area for fish and fish habitat included the watercourses that may be crossed by the preferred corridor or Rockwood Park variants and where activities associated with the Project could potentially result in environmental effects on fish, fish habitat, and surface water quality.

49 The six Maliseet First Nation communities in New Brunswick are Madawaska, Tobique, Woodstock, Kingsclear, St. Mary's and Oromocto. The nine Mi'kmaq commu-

nities in New Brunswick are Eel River Bar, Pabineau, Burnt Church, Metepenagiag, Eel Ground, Big Cove, Indian Island, Buctouche, and Fort Folly.

50 UNBI is the Aboriginal organization representing the following 12 First Nations in New Brunswick: Madawaska, Woodstock, Kingsclear, St. Mary's, Oromocto, Eel River Bar, Pabineau, Metepenagiag, Eel Ground, Indian Island, Buctouche, and Fort Folly.

51 The MAWIW Council was formed by the Chiefs of the three most populous First Nations in New Brunswick: Big Cove, Burnt Church, and Tobique.

52 Alliance, *supra* note 4 at page 164, and Sable, *supra* note 4 at page 53.

53 *Bow Valley Naturalists Society* v. *Canada (Minister of Canadian Heritage)*, [2001] F.C.J. No. 18 (F.C.A.) at para. 75.

54 The Canadian Environmental Assessment Agency's October 1998 Operational Policy Statement addressing the "need for" the project, the "purpose of" the project, the "alternatives to" the project and "alternative means" of carrying out the project, provides definitions and general guidance on when and how these factors should be considered.

55 Correction to this word in the original transcript was made in transcript volume 12, paragraph 19686.

56 R.S. 1985, c. N-7.

57 Westcoast Energy Inc. (GH-5-94), Transcript volume 3 (8 February 1995), at 340-342.

58 For example, the Board's Letter Decision dated 5 September 2002 on Westcoast Energy Inc.'s Southern Mainline Expansion Project (GH-1-2002) and the Board's Letter Decision dated 14 February 2003 on Sumas Energy 2, Inc.'s application for an international power line (EH-1-2000).

Tab 3

Memorial Gardens Assn (Can. Ltd. V. Colwood Cemetery Co., [1958] S.C.R. 353, 1958 Can LII 82

Supreme Court of Canada
Memorial Gardens Association (Canada) Limited v. Colwood Cemetery Company, [1958] S.C.R. 353
Date: 1958-04-22

Memorial Gardens Association (Canada) Limited *Appellant;*

and

Colwood Cemetery Company, Board of Cemetery Trustees of Greater Victoria, Corporation of The District of Saanich, The Corporation of The City of Victoria, Edwin J. Freeman, Helen J. Freeman, A. C. Kinnersley, Lola Kinnersley, H. M. Palsson, Jean Laban, C. J. Laban, Shirley R. Crockett, B. I. Crockett, F. A. Kinnersley, Vernice Rockwell, Peter C. Sharp, L. H. Sharp And Alexander Horbatuk and Public Utilities Commission *Respondents.*

1958: February 3, 4; 1958: April 22.

Present: Kerwin C.J. and Taschereau, Locke, Cartwright and Abbott JJ.

ON APPEAL FROM THE COURT OF APPEAL FOR BRITISH COLUMBIA

Public utilities—"Public convenience and necessity"—Meaning of phrase—Review of decision of Commission—The Public Utilities Act, R.S.B.C. 1948, c. 277, ss. 58, 72, 75, 100—The Cemeteries Act, R.S.B.C. 1948, c. 41, ss. 2, 3, as enacted by 1955, c. 7, s. 3.

Per Kerwin C.J. and Taschereau, Cartwright and Abbott JJ.: It is impracticable and undesirable to attempt a precise definition of the phrase "public convenience and necessity". It is clear from the American decisions that the word "necessity" as here used does not bear its strict dictionary meaning. Its meaning must be ascertained in each case by reference to the context and to the objects and purpose of the statute in which it is found; in particular, it has been held that the word is not restricted to present needs but includes provision for the future. *Wabash, C. & W. Ry. Co. v. Commerce Commission* (1923), 141 N.E. 212, referred to.

The Public Utilities Commission of British Columbia granted a certificate of public convenience and necessity to the appellant company for the operation, through a subsidiary company, of a cemetery on Vancouver Island. This certificate was set aside by the Court of Appeal.

Held: The judgment of the Court of Appeal should be set aside and the certificate should be restored.

Per Kerwin C.J. and Taschereau, Cartwright and Abbott JJ.: The Commission's decision that public convenience and necessity required the establishment of a new cemetery was not one of fact but was predominantly the formulation of an opinion based upon the facts established before the Commission. There was evidence to support

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the findings of fact made by the Commission and its exercise of administrative discretion based on those findings should not be interfered with by the Courts. *Union Gas Company of Canada Limited v. Sydenham Gas and Petroleum Company Limited,* [1957] S.C.R. 185, applied.

Subsidiary grounds of attack on the Commission's decision should be disposed of as follows: (1) the fact that the appellant proposed to operate the cemetery by means of a subsidiary company to which the Commission agreed to grant a second certificate on incorporation was not an objection to the grant of the certificate to the appellant; (2) the fact that the appellant held only an option on the lands in question was not a ground for'refusing the certificate, since the option, assuming it to be enforceable, made the appellant an "owner" within the meaning of the statute; (3) there was no ground, in the circumstances of the case, for saying that the Commission had unjustifiably received evidence without permitting the respondents to see it, thus preventing cross-examination and violating the rule *audi alteram partem. Toronto Newspaper Guild v. Globe Printing Company,* [1953] 2 S.C.R. 18, distinguished.

Per. Locke J.: The option was produced for examination by the Commission with the express consent of counsel for the parties who now objected, and they should not now be heard to allege that the proceedings were invalidated by this circumstance. *Scott v. The Fernie Lumber Company, Limited* (1904), 11 B.C.R. 91 at 96, approved and applied. In other respects, the appeal failed for the reasons given by Sheppard J.A. in his dissenting judgment in the Court of Appeal.

APPEAL from a judgment of the Court of Appeal for British Columbia[1], setting aside a certificate of public convenience and necessity granted by the Public Utilities Commission. Appeal allowed.

Alan B. MacFarlane and E. A. Popham, for the appellant.

D. M. Gordon, Q.C., for the respondents,

The judgment of Kerwin C.J. and Taschereau, Cartwright and Abbott JJ. was delivered by

ABBOTT J.:—The question raised on this appeal is whether a certificate of public convenience and necessity issued by the Public Utilities Commission of British Columbia, under the provisions of the *Public Utilities Act,* R.S.B.C. 1948, c. 277, as amended, was authorized in law.

By the *Cemeteries Act Amendment Act, '1955* (B.C.), c. 7, cemeteries in British Columbia were brought under the jurisdiction of the *Public Utilities* Commission as constituted under the *Public Utilities Act,* the relevant

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sections of the *Cemeteries Act,* R.S.B.C. 1948, c. 41, as enacted by s. 3 of the 1955 statute, reading as follows:

Regulation of Cemeteries, Crematoria, and Columbaria.

[1] (1957); 22 W.W.R. 348,..9 D.L.R. (2d) 653, 75 C.R.T.C. 292.

2. A cemetery shall not be established or enlarged until the Minister of Health and Welfare has approved of the site of the cemetery as a fit and proper place for the interment of the dead and the owner thereof has obtained from the Commission a certificate of public convenience and necessity under the "Public Utilities Act."

3. (1) The Commission shall have jurisdiction over all cemeteries, columbaria, and crematoria, and the owners thereof, and shall exercise with respect thereto all the powers, duties, and functions relating to public utilities conferred or imposed by the "Public Utilities Act" on the Commission, to the extent to which such powers, duties, and functions are exercisable; and the provisions of the "Public Utilities Act" (other than Part IV thereof), so far as appropriate, shall aply to cemeteries, columbaria, crematoria, and the owners thereof.

(2) Without limiting the generality of subsection (1) and notwithstanding the provisions of the "Cemetery Companies Act," the "Cremation Act," or the "Municipal Cemeteries Act," the Commission may, with the approval of the Lieutenant-Governor in Council, make regulations:

(*a*) Respecting the burial, disinterment, removal, and disposal of the bodies or other remains of deceased persons;

(*b*) Respecting the plans, survey, arrangement, condition, care, sale, and conveyancing of lots, plots, and other cemetery grounds, and property;

(*c*) Respecting the erection, arrangement, and removal of tombs, vaults, monuments, gravestones, markers, copings, fences, hedges, shrubs, plants, and trees in cemeteries;

(*d*) Respecting charges for the sale and care of lots and plots;

(*e*) Respecting the collection, amounts to be collected, and investment of funds for perpetual care and maintenance of cemeteries;

(*f*) Requiring the filing or registration of plans of cemeteries and prescribing the contents and details of such plans, and requiring that burials be made in accordance with such plans;

and such regulations may be general in their application or may be made applicable specially to any particular locality or cemetery.

(3) Every person who fails or refuses to obey a regulation of the Commission made under this section is guilty of an offence and liable, on summary conviction, to a penalty of not less than ten dollars and not more than five hundred dollars.

The appellant proposed to establish and operate a new cemetery in the vicinity of Victoria and, as required by the statute, applied to the Public Utilities Commission for a certificate of public convenience and necessity. There were at the time two cemeteries in the area, one, the Colwood Cemetery, operated by a privately-owned company, the other, the Royal Oak Cemetery, a municipallyoperated cemetery controlled by the City of Victoria and the Municipality of Saanich. Appellant's application was

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opposed by those in control of the two existing cemeteries and by certain owners of property adjoining the site of the proposed new cemetery.

After a hearing at which evidence was taken as to the need for cemeteries in the Victoria area, both present and future, the Commission issued the certificate requested. Under s. 100 of the *Public Utilities Act* an appeal from a decision of the Commission lies to the Court of Appeal, by leave, only upon a question of law or as to the jurisdiction of the Commission. Appeal was taken to the Court of Appeal for British Columbia and by a majority decision the Court of Appeal[2] allowed the appeal and held that the certificate should be set aside. The present appeal is from that judgment. Sheppard J. A., while dissenting on the main issues raised, would have referred the matter back to the Commission for a rehearing on one matter.

The term "public convenience and necessity" appears to have been brought into the statute law in Canada from the United States and a great many decisions were cited to us indicating the meaning given to the term in that country. It is clear from these decisions that the word "necessity" as contained in these American statutes cannot be given its dictionary meaning in the strict sense: *Canton-East Liverpool Coach Co. et al. v. Public Utilities Commission of Ohio*[3]*; Wisconsin Telephone Co. v. Railroad Commission of Wisconsin et al.*[4]*]; Wabash, C. & W. Ry. Co. v. Commerce Commission*[5]*; San Diego & Coronado Ferry Co. v. Railroad Commission of California et al*[6]*].* The meaning in a given case must be ascertained by reference to the context and to the objects and purposes of the statute in which it is found.

The term "necessity" has also been held to be not restricted to present needs but to include provision for the future: *Wabash, C. & W. Ry. Co. v. Commerce Commission, supra,* at p. 215, and this indeed would seem to follow from s. 12 of the *Public Utilities Act,* which provides that the certificate may issue where public convenience and necessity "require or *will require"* such construction or operation.

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It is obvious I think, that the phrase "public convenience and necessity" when applied to cemeteries cannot be given precisely the same connotation as when it is applied to those operations more commonly looked upon as public utilities, such as electric power services,

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[2] (1957), 22 W.W.R. 348, 9 D.L..R. (2d) 653, 75 C.R.T.C. 292.
[3] (1930), 174 N.E. 244.
[4] (1916), 156 N.W. 615.
[5] (1923), 141 N.E. 212 at 214.
[6] (1930), 292 P. 640 at 643.

water-distribution systems, railway lines and the like, and this is borne out both by the terms of the statute which I have quoted and by the decisions of the American Courts to which we were referred.

The phrase also appears in *The Municipal Franchises Act,* R.S.O. 1950, c. 249 (considered by this Court in *Union Gas Company of Canada Limited v. Sydenham Gas and Petroleum Company Limited*[7]*),* in the *Aeronautics Act,* R.S.C. 1952, c. 2, and I have no doubt in other provincial and federal statutes, and it would, I think, be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity. As has been frequently pointed out in the American decisions, 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.

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.

The findings of fact made by the Commission have been concisely set forth by Sheppard J.A. in his reasons[8], and are in part as follows:

> (1) That there are two established cemeteries in the district in question, namely, Royal Oak and Colwood, and these have vacant space adequate for immediate needs;

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> (2) That the services proposed by the appellant company are similar to those now available at Royal Oak; that Colwood is not a modern, but an older, type of cemetery; that Colwood has proposed modernizing but that may be reconsidered if the respondent' [now appellant] company is permitted to establish a cemetery;
>
> (3) That the established cemeteries, Royal Oak and Colwood, are not adequate for the future; that the available space at Royal Oak will be filled in 10 to 15 years; that the need for the future is recognized by both these cemeteries in that both are presently negotiating for additional land;

[7] [1957] S.C.R. 185, 7 D.L.R. (2d) 65, 75 C.R.T.C. 1.
[8] 22 W.W.R. at p. 362.

(4) That vacant cemetery spaces will be needed for the future; that the modern-type cemetery may, by reducing the public demand for cremation, increase the rate at which the available space will be filled.

There was evidence before the Commission upon which it could make the findings of fact which it did. In my opinion the majority of the Court of Appeal in holding that in law the Commission could not find necessity upon the facts recited in its judgment was merely substituting its opinion for that of the Commission. As this Court held in the *Union Gas* case, *supra,* this is not a question of law upon which an appeal is given, and the Court below was therefore without jurisdiction. It would have been otherwise if it had been shown that the Commission had given a meaning to the words of the statute which as a matter of law they could not bear.

Three subsidiary points were raised by respondents. As set out in their factum these are as follows:

1. The Commission went beyond the authority given by the statute by granting the appellant a certificate, though the appellant was not meant to establish or operate the cemetery itself, but to form a subsidiary to do that, to which the Commission bound themselves to give a second certificate; .

2. The appellant had no basis for its application for a certificate except an option to buy a site, and the statute required it to be an "owner";

3. The Commission unjustifiably received evidence of the option without permitting the respondents to see it, thus preventing cross-examination and infringing the *audi alteram partem* rule.

As to points 1 and 2, I agree with the views expressed by Sheppard J.A. that the certificate appears to be within the powers conferred by the statute and that the option held by appellant, assuming it to be enforceable, did enable appellant to obtain and assert a control sufficient to constitute appellant an owner within the meaning of the statute.

As to the third point, at the hearing before the Commission appellant called as witnesses the persons from whom the option referred to had been obtained, and the

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option itself was filed with the Commission. Appellant was apparently unwilling to exhibit the document to respondents at that time since this would have involved disclosing the purchase-price and the transcript of evidence on this point reads in part as follows:

Mr. GORDON : Just one point, since the option itself has been the subject-matter of considerable discussion. I wonder if it might be produced for examination by the Commission? There have been certain representations regarding it as to detail, as to length of time and certain questions have now arisen. Could the Commission have it produced, merely to verify statements that have been made?

Mr. MACFARLANE : I am prepared to produce it to the Commission but not to my learned friends. Now, I state that that option has been executed by these people, Mr. and Mrs. Turner. These people have sworn under oath here to-day that they executed such an option. I state that the option is in favor of James H. Edwards, the President of Memorial Gardens Association of Canada Limited. They swear the property that it covers and they swear the expiry date. I have the option here but I am not going to tell my learned friends the price that Memorial Gardens Association Limited is paying for this property, which they would dearly like to know and which is Mr. and Mrs. Turner's private business. The company doesn't care if everybody knows but Mr. and Mrs. Turner are selling it for a price, it is up to them.

Mr. GORDON : It is essential to the jurisprudence to produce the document about which you are discussing. It is the document, the very basis of the matter which we are dealing with. Simply to make an oath on something when—

The CHAIRMAN: I think the document should be produced to the Commission, whose officers are under oath not to disclose confidential information, but if the document itself does contain certain information that is confidential, it needn't be disclosed to the public.

Mr. MACFARLANE: That is my point. I am quite happy to disclose the information to the Commission but I don't feel it is such that should be disclosed—

Mr. GORDON : May I just simply add this, that in respect to this option, certain statements were made as to when it was entered into, as to what period it was extended to, asking the Commission to make a hurried decision in order to meet with its requirements. If these things are all in the option, we know at least that is *bona fide* but having sworn statements made without the basic documents there at least to the Commission, is of little value.

The CHAIRMAN: The Commission will have the opportunity of comparing the statements with the document.

Mr. GORDON : Well, that is perfectly satisfactory to me.

It does not appear from the record that any person opposing the application other than Mr. Gordon asked for the production of the option and Mr. Gordon stated that he was satisfied with the procedure proposed by the Commission. These circumstances clearly distinguish this case

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from that of *Toronto Newspaper Guild v. Globe Printing Company*[9]*]*. In these circumstances and in view of the provisions of ss. 58, 72 and 75 of the *Public Utilities Act* in my opinion this third point does not avail the respondents.

[9] [1953] 2 S.C.R. 18, [1953] 3 D.L.R. 561, 106 C.C.R. 225.

For the reasons which I have given, as well as for those of Sheppard J.A. as to the main issue, with which I am in substantial agreement, I would allow the appeal with costs here and below and restore the certificate.

LOCKE J.:—With the exception hereinafter mentioned, I agree with the reasons for judgment delivered by Mr. Justice Sheppard.

While the record does not disclose the fact, I assume that Mr. Gordon, who cross-examined certain of the witnesses on behalf of the Colwood Cemetery Company, is a member of the bar of British Columbia and that he acted in that capacity at the hearing before the Public Utilities Commission. We were informed at the hearing of this appeal that the person referred to was not Mr. D. M. Gordon, Q.C., who appeared for the respondents before us.

The passage from the transcript quoted in the reasons of my brother Abbott, which I have had the advantage of reading, shows that Mr. Gordon asked that the option might be produced for examination by the Commission "merely to verify statements that have been made". The chairman ruled that this should be done and counsel for the appellant at once agreed that the information should be disclosed to the Commission. When the chairman said that the Commission would have the opportunity of comparing the statements that had been made with the document, Mr. Gordon said that that was perfectly satisfactory. None of the other parties represented before the Commission appear to have evidenced any interest in the nature of the option. Having thus led the members of the Commission to understand that the course proposed was satisfactory to his clients, they should not now be heard to allege that the proceedings were invalidated by the

very course of conduct that they assented to: *Scott v. The Fernie Lumber Company, Limited1.*

I would allow this appeal with costs in this Court and in the Court of Appeal.

Appeal allowed with costs.

Solicitors for the appellant: Clay, MacFarlane, Ellis & Popham, Victoria.

Solicitors for the respondent Colwood Cemetery Company: Crease & Co., Victoria.

Solicitors for the respondent cemetery trustees: Gregory, Grant, Cox & Harvey, Victoria.

Solicitors for the respondent District of Saanich: Manzer, Wootton & Drake, Victoria.

Solicitor for the respondent District of Victoria: T. P. O'Grady, Victoria.

Solicitor for the individual respondents: A. J. Patton, Victoria.