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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER E-1-05

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

and

A Filing by British Columbia Hydro and Power Authority
Call for Tenders for Capacity on Vancouver Island
Review of Electricity Purchase Agreement

BEFORE: R.H. Hobbs, Chair
L.A. Boychuk, Commissioner February 17, 2005

O R D E R

WHEREAS:

A. On November 19, 2004, British Columbia Hydro and Power Authority ("BC Hydro") submitted to the British Columbia Utilities Commission ("Commission") the Electricity Purchase Agreement ("EPA") and Vancouver Island Generation Project Transfer Agreement ("VIGP Transfer Agreement") with Duke Point Power Limited Partnership ("Duke Point Power") and a Report on the BC Hydro Call for Tenders on Vancouver Island ("CFT") Process ("the CFT Report"); and

B. Pursuant to Order No. G-99-04, on November 29 and 30, 2004, the Commission Panel held a Procedural Conference regarding an effective and efficient regulatory process for the review of BC Hydro's EPA filing and CFT Report; and

C. At the Pre-hearing Conference on November 30, 2004, the Commission Panel made determinations regarding the scope of the proceeding and directed that a Public Hearing, and a Town Hall Meeting in Nanaimo, would take place. Order No. G-106-04 established the Regulatory Agenda for the proceeding; and

D. Pursuant to Letter No. L-62-04, on December 17, 2004 the Commission Panel held a Pre-hearing Conference to consider an application by BC Hydro seeking relief with respect to responding to certain Information Requests. Commission Letter No. L-63-04 set out the Commission Panel's determinations with regard to the application for relief; and

E. Pursuant to Order No. G-106-04, on December 22, 2004 the Commission Panel held a Pre-hearing Conference to address matters that were identified in Letter No. L-64-04, including applications related to reasonable apprehension of bias, the scope of the proceeding and the disclosure of confidential information. The Pre-hearing Conference also considered revisions to the Regulatory Timetable; and

F. At the December 22, 2004 Pre-hearing Conference, Commissioner Birch recused himself from the proceeding; and

…/2

G. Following the December 22, 2004 Pre-hearing Conference, the Commission Panel issued Order No. G-119-04 which included revisions to the Regulatory Agenda established by Order No. G-106-04; and

H. Pursuant to Order No. G-119-04, the Town Hall Meeting took place on January 15, 2005 in Nanaimo, B.C.; and

I. Further pursuant to Order No. G-119-04, the Public Hearing took place from January 17 to January 28, 2005 in Vancouver, B.C.; and

J. Written Final Arguments and Reply Argument were completed by February 7, 2005. An oral argument phase was held on February 10, 2005 so counsel could respond to specific issues arising from the written argument process identified by the Commission Panel; and

K. The Commission Panel has considered the EPA, the VIGP Transfer Agreement, the Report on the BC Hydro CFT Process, the written evidence filed prior to and during the hearing, the Letters of Comment, and the written and oral arguments submitted by the parties.

NOW THEREFORE the Commission orders as follows:

1. For reasons to follow, the EPA is accepted as filed as an energy supply contract pursuant to Section 71 of the Utilities Commission Act, subject to the following conditions:

   (a) that BC Hydro purchase firm gas transportation service from Terasen Gas (Vancouver Island) Inc. ("TGVI") to serve Duke Point Power's proposed power plant at Duke Point near Nanaimo, British Columbia ("Duke Point Power Plant"); and

   (b) within 45 days of the date of this Order, that BC Hydro enter into, and facilitate the filing with the Commission of, a long-term firm gas transportation service agreement ("TSA") with TGVI to serve both the Duke Point Power Plant and the Island Cogeneration Plant at Elk Falls, near Campbell River, British Columbia.

2. The acceptance of the EPA for filing as an energy supply contract is further subject to the following directions:

   (a) within 10 days of the date of this Order, BC Hydro is to provide written notice to the Commission of its intention to proceed with the EPA; and

   (b) within 45 days of the date of this Order, BC Hydro is to notify the Commission if it has been unable to reach an agreement on the terms of a TSA with TGVI; and

   (c) in the event of a failure to reach an agreement on the terms of a TSA with TGVI within 45 days of the date of this Order, or in the event a filed TSA is not acceptable to the Commission and the Commission does not approve the terms of a filed TSA, either wholly or in part, BC Hydro is to apply to the Commission for further directions; and

…/3

(d) BC Hydro is to carry forward in a designated deferral account the $50 million payment received from Duke Point Power under the VIGP Transfer Agreement together with any carrying charges associated with that payment until BC Hydro has made an application providing for the manner of the disposition of the payment and the Commission has made a determination thereon. This designated account is to be separate from the designated account approved by Commission Order No. G-54-04. The application for disposition is to be made concurrently with the application contemplated by Commission Order No. G-54-04; and

(e) BC Hydro is to comply with any other directions in the reasons to follow.

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of February 2005.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

CALL FOR TENDERS FOR CAPACITY ON VANCOUVER ISLAND
AND
REVIEW OF ELECTRICITY PURCHASE AGREEMENT

REASONS FOR DECISION
to Order No. E-1-05

March 9, 2005

Before:

Robert H. Hobbs, Chair
Lori Ann Boychuk, Commissioner

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1.0 INTRODUCTION

1.1 Electricity Purchase Agreement and CFT Report

By letter dated November 3, 2004, British Columbia Hydro and Power Authority (“BC Hydro”, “Utility”) advised the British Columbia Utilities Commission (the “Commission”, “BCUC”) that Duke Point Power Limited Partnership (“Duke Point Power”, “DPP”) was the successful proponent in the Vancouver Island Call for Tenders (“CFT”) process and that DPP had been offered an electricity purchase agreement for 252 Megawatts (“MW”) of capacity from the proposed plant (“DPP plant”). BC Hydro stated that it would file the executed agreement in accordance with section 71 of the Utilities Commission Act (the “Act”, “UCA”).

On November 19, 2004, BC Hydro submitted on a confidential basis a copy of the Electricity Purchase Agreement (Capacity and Associated Energy) for Vancouver Island made as of November 16, 2004 (the “EPA”) with Duke Point Power. The confidential submission included a copy of the Vancouver Island Generation Project (“VIGP”) Transfer Agreement with DPP made as of November 16, 2004 (Confidential Exhibit B-4).

Also on November 19, 2004, BC Hydro filed the Call for Tenders for Capacity and Associated Energy Supply on Vancouver Island – Report on the Call for Tenders Process (“CFT Report”, Exhibit B-1). The CFT Report described the CFT process that led to the selection of the DPP tender.

BC Hydro executed the EPA with DPP following the determination of BC Hydro’s senior management that the portfolio recommended to it “represented the most cost-effective solution for addressing the Vancouver Island supply shortfall having regard to ratepayer interests” (Exhibit B-1, p. 19). This was the CFT option for a gas-fired combined cycle power plant to be located near the Duke Point industrial area of Nanaimo, B.C. The EPA is a full tolling arrangement (Exhibit B-9, BCUC IR 1.23.1). DPP plans to commence construction of the plant in March 2005 and to achieve commercial operation by May 2007 (Exhibit B-1, p. 19). The plant would include full duct-firing capability (Exhibit C17-8, Unredacted p. 74 of EPA). Under the EPA, BC Hydro contracted for 252 MW of plant capacity, but did not contract for the additional 28 MW that would result from duct-firing (T10: 2210). BC Hydro accepted the bid that in its view was the successful outcome of the CFT process.

The VIGP Transfer Agreement provides for the sale to DPP of BC Hydro’s VIGP assets, consisting primarily of land, a steam turbine, and current environmental and other permits necessary to construct a combined cycle gas turbine plant at the site, for a price of $50 million (Exhibit B-1, p. 3). The Vancouver

Island Energy Corporation (“VIEC”) was formed as a wholly-owned subsidiary of BC Hydro for the purposes of the VIGP. The Environmental Assessment Certificate (“EAC”) granted to VIEC relating to the VIGP assets will be transferred to DPP as part of the share and asset transaction. Under the terms of Schedule B of the EAC, BC Hydro committed to offset 50 percent of the increase in emissions from VIGP through 2010, through new energy efficiency and renewable energy efforts. BC Hydro fulfilled this commitment before the CFT was contemplated. Therefore, although the responsibility for the 50 percent offset commitment to 2010 will not be transferred to DPP, BC Hydro considers that the net present value of the commitment in relation to DPP is zero (Exhibit B-104, GSXCCC Supplemental IR 2.7.2).

On December 3, 2004, BC Hydro filed a redacted copy of the EPA (Exhibit B-6). On December 29, 2004, pursuant to Order No. G-119-04, BC Hydro disclosed Appendix 3 of the EPA, from which only subsections 1.1(hh), 1.1(ii) and 1.1(jj) relating to start-up costs were redacted (Exhibit B-19). On January 11, 2005, DPP disclosed other sections of the EPA (Exhibit C17-8).

On January 20, 2005, BC Hydro filed Amending Agreement No. 1 to the EPA and VIGP Transfer Agreement dated January 20, 2005 which, *inter alia*, extended the provision for regulatory review termination from a 90-day to a 94-day period to accommodate an anticipated February 17, 2005 Decision date (Exhibit B-73; T9: 2052-2053).

1.2 VIGP Decision

The CFT Report states that BC Hydro considers the CFT process to be a continuation of the VIGP Certificate of Public Convenience and Necessity (“CPCN”) process (Exhibit B-1, p. 24). In March 2003, VIEC applied for a CPCN for the VIGP at Duke Point near Nanaimo. In its September 8, 2003 Decision on the VIGP (the “VIGP Decision”), the Commission concluded that in the context of its review of the CPCN application, the proposed site is suitable for the VIGP (VIGP Decision, p. 52). However, the Commission denied the CPCN Application because VIEC had not established that VIGP was the most cost-effective means to reliably meet Vancouver Island power needs (VIGP Decision, p. 77). The Commission confirmed that there will be a capacity shortfall on Vancouver Island and found that there is a need to move expeditiously to reinforce electricity supply to Vancouver Island prior to the winter of 2007/08 (VIGP Decision, p. 78). The VIGP Decision also stated:

> "The Commission Panel encourages BC Hydro to proceed with a CFT on the schedule set forth in Schedule A in VIEC's Reply Argument at pages 45 and 46. Based on the results of the CFT, the Commission is prepared to consider any future application for CPCN approval or Electricity Purchase Agreement approval on an expedited basis."
>
> (VIGP Decision, p. 77)

At the November 30, 2004 Procedural Conference the Chair, following submissions by parties, stated that the Commission Panel accepted the following determinations from the VIGP Decision as relevant to a determination of the scope of this proceeding:

> "The first item: The evidence from this hearing suggests that the appropriate next resource addition should be on-Island generation, provided the cost of the proponents' projects can be confirmed near their expected value, and that's found at page 78 of the VIGP decision.
>
> The next item: Given the Commission Panel's determination that the logical next resource addition is on-Island generation, it should be possible to develop a simplified NPV [Net Present Value] model specifically for the CFT. The NPV model should be available to bidders in advance, and the Commission Panel believes it should be limited to on-Island generation costs without the need to consider future impacts to electricity transmission or generation on the mainland. And that's found at page 81.
>
> Next item: The Commission Panel accepts that evidence – accepts the evidence that there is a capacity shortfall on Vancouver Island, commencing in the winter of 2007/08. And that's found at page 27."

The Chair further stated that the foregoing determinations were not a comprehensive list of the VIGP Decision determinations that were relevant to this proceeding (T2: 307-308).

The Chair also stated that the record from the VIGP proceeding would not form part of the evidentiary record of this proceeding, except for evidence that is relevant to the timing of a new 230 kV transmission line to Vancouver Island. However, participants could apply to the Commission for approval to include other evidence from the VIGP proceeding as part of the record of this proceeding (T2: 309-310).

1.3 Procedural Orders and Hearing Process

By letter dated November 3, 2004, BC Hydro advised the Commission that it would be filing the EPA with DPP in accordance with section 71 of the Act. The Commission Panel, by Order No. G-99-04 dated November 10, 2004, established a Procedural Conference commencing November 29, 2004 to consider a regulatory process for the review of the EPA (Exhibit A-1). In a letter dated November 24, 2004, the

Commission Panel identified the issues that would be discussed and stated that it anticipated the Procedural Conference would continue on November 30, 2004 (Exhibit A-2).

At the Procedural Conference on November 30, 2004, in addition to the Commission Panel's determinations regarding the relevance of certain conclusions in the VIGP Decision in establishing the scope of the EPA review and on the issue of confidentiality generally, the Chair also confirmed that certain Commission Information Requests issued on November 26, 2004 (Exhibits A-3, A-4) would be re-issued in compliance with the scope determination. With respect to timing of the process and an anticipated Commission decision, the Chair stated that:

> "…the Commission Panel also intends to issue a decision with respect to the EPA filing within 90 days of its filing, and intends to balance the need to avoid a violation of planning criteria, arising from the zero rating of the HVDC line, with the need for a full and complete record on the issues identified for this proceeding. And I will expedite the process as necessary so a decision is issued by February the 17^{th} , 2005." (T2: 315)

Following the Procedural Conference the Commission issued Order No. G-106-04 which established an oral public hearing to commence on January 11, 2005, and established the Regulatory Agenda for the proceeding which included a Pre-hearing Conference to be held on December 22, 2004, and a Town Hall Meeting in Nanaimo on January 15, 2005 (Exhibit A-7).

The Commission Panel, by Letter No. L-62-04 (Exhibit A-12), established another Pre-hearing Conference on December 17, 2004 in response to a request from BC Hydro for an Order to relieve it from the obligation to respond to certain Information Requests (Exhibit B-8). Following the December 17, 2004 Pre-hearing Conference, the Commission Panel issued Letter No. L-63-04 which approved BC Hydro's application for relief, except for certain specified Information Requests (Exhibit A-13).

The Commission Panel, by Letter No. L-64-04, set out the Agenda for the second Pre-hearing Conference on December 22, 2004 (Exhibit A-14). At that Pre-hearing Conference, Commissioner Birch recused himself from the proceeding. After the Pre-hearing Conference, the Commission Panel issued Order No. G-119-04 (with Reasons for Decision to follow) which delayed the start of the hearing to January 17, 2005, set out a Revised Regulatory Agenda, determined that most of Appendix 3 of the EPA would be disclosed, and made determinations on several reconsideration applications and other requests (Exhibit A-16). The Commission Panel's Reasons for Decision related to confidential matters and the disclosure of Appendix 3 were subsequently issued by letter dated January 6, 2005 (Exhibit A-19).

By a letter dated January 13, 2005, the Commission Panel issued a schedule showing the proposed timeline for each of the witness panels that were expected to testify at the hearing (Exhibit A-38). The purpose of the schedule was to facilitate the completion of the hearing within the timeline identified in the Commission's January 11, 2005 letter (Exhibit A-24). Eleven hearing days were scheduled for this purpose commencing on January 17, 2005.

A Town Hall Meeting was held on January 15, 2005 in Nanaimo. The Commission Panel received presentations from 33 individuals and groups who generally expressed concern about the EPA and the Duke Point Power facility that is associated with it. The Commission Panel appreciates the efforts of the presenters to make their views known to the Commission. As many of the presenters had acknowledged, concerns related to certain environmental and siting matters had already been provided and had already been considered and addressed in relation to a proposed gas-fired generation plant at Duke Point in the context of the previous extensive proceeding and Commission Decision on the VIEC Application for the VIGP (VIGP Decision, Chapter 5.10). In addition, the VIGP has already received an EAC which will be transferred to DPP under the VIGP Transfer Agreement.

The Public Hearing in Vancouver commenced on January 17, 2005 and finished on January 28, 2005. BC Hydro and DPP submitted their Arguments on February 1, 2005, other Intervenors submitted their Arguments on February 4, and BC Hydro and DPP submitted their Replies on February 7, 2005. An Oral Argument Phase was held on February 10, 2005.

By Order No. E-1-05 dated February 17, 2005, the Commission Panel accepted the EPA for filing pursuant to section 71 of the Act, with Reasons to follow. These are the Reasons.

1.4 Scope of the Proceeding

At the November 30, 2004 Procedural Conference the Chair set out the scope for the proceeding under the following headings:

- Transmission Alternatives;
- Transmission 230 kV Supply Timing;
- Construction and Construction Cost Overruns;
- Performance Risk of the Duke Point Plant;
- Gas Supply Price Risk;
- Load Forecast;

- CFT Criteria, including Mandatory Criteria and Quantitative Evaluation Methodology ("QEM") Criteria;
- Gas Transportation Risk;
- Gas Transportation Alternatives; and
- Gas Transportation Costs.

The "scope ruling" is set out at Transcript pages T2: 309-314. The Chair also identified the Principal Issue for the proceeding as follows:

> "Is Tier 2, Tier 1, or the No Award option the most cost-effective option to meet the capacity deficiency on Vancouver Island commencing in the winter of 2007/08?"

At the December 17, 2004 Pre-hearing Conference, the Chair subsequently clarified that counsel for BC Hydro was correctly interpreting the Commission Panel's decision when counsel stated "…the treatment, within the QEM process and the whole CFT process, of specific tenders and whether or not the reasons that they were rejected at various stages of the process were appropriate or fair or whatever" and "…whether or not Hydro properly applied its own criteria in evaluating the different bids" were outside the scope of the proceeding (T3: 413-414). Whether or not BC Hydro properly applied its CFT criteria was a subject of the reports of the Independent Reviewer (Exhibit B-1, Appendix K).

The Chair also stated that he was able "…to confirm what was intended in the reference to Tier 1, Tier 2 and the no awards, as it related to the Principal Issue. It was intended that the description at Appendix J [in Exhibit B-1] that we spoke to prior to the break was the definition of Tier 1, Tier 2 and the no award scenario. So that does, then, mean that when we're referring to Tier 1, we are only referring to the winning Tier 1 bid. Similarly for Tier 2. Tier 2 is the [two smaller projects totalling] 122 megawatts" (T3: 453).

2.0 THE REGULATORY PROCESS

2.1 Reconsideration and Disqualification Applications

2.1.1 Reconsideration and Other Applications

The BC Old Age Pensioners Organization et al. ("BCOAPO") in Exhibit C3-4, and the Joint Industry Electricity Steering Committee ("JIESC") in Exhibit C19-5, applied for reconsideration of a Commission Panel determination related to disclosure of confidential information. Commission Order No. G-119-04 denied the applications (Exhibit A-16).

The JIESC applied for reconsideration of a Commission Panel determination related to the scope of the proceeding (Exhibit C19-5). Following a written Phase 1 reconsideration process established by Order No. G-119-04, Commission Letter No. L-3-05 and Reasons for Decision concluded that a prima facie case had not established that an error in fact or law had been made in the determination of the scope for the proceeding (Exhibit A-36).

The GSX Concerned Citizens Coalition ("GSXCCC") and B.C. Sustainable Energy Association ("BCSEA") applied for admission as evidence in this proceeding certain evidence from the VIGP proceeding (Exhibit C20-12). Commission Letter No. L-1-05 approved the application (Exhibit A-17).

Duke Point Power applied for two Orders regarding the filing of information (Exhibit C17-2). Commission Order No. G-01-05 denied the application (Exhibit A-20).

The GSXCCC and BCSEA requested that the Commission Panel order BC Hydro to provide information regarding the Vancouver Island peak load (Exhibits C20-18, C20-19, C20-22). The Commission Panel by letter dated January 11, 2004 denied the applications (Exhibit A-25).

The JIESC requested that the Commission Panel make three orders with certain directions to BC Hydro (Exhibit C19-13). The Commission Panel by letter dated January 11, 2004 denied the application (Exhibit A-26).

Vanport Sterilizers Inc. (“Vanport”) applied for reconsideration of certain aspects of Order No. G-119-04 denying requests Vanport had made, and of decisions related to the Georgia Strait Crossing pipeline (Exhibit C39-4). Commission Letter No. L-2-05 denied the application (Exhibit A-35).

GSXCCC, BCSEA and the Society Promoting Environmental Conservation (collectively “GSXCCC et al.”) applied for reconsideration of certain decisions of the Commission Panel regarding the conduct of the proceeding (Exhibit C20-29). Commission Letter No. L-8-05 denied the application (Exhibit A-45).

Following a motion made by Green Island Energy Ltd. (“Green Island”) on January 28, 2005 the Commission Panel agreed to accept, subject to probative value, weight and relevance, a filing by Calpine Island Cogeneration Limited Partnership (“Calpine”) of its bid by 12:00 noon, Monday, January 31, 2005. Calpine is not a registered intervenor in this proceeding but had filed a letter of comment on January 6, 2005 advising the Commission that it would not object to an order directing BC Hydro “to file, confidentially with the Commission, Calpine’s Island Cogeneration Project bid, including the price information form that was submitted in response to the VICFT” (Exhibit E-123). Counsel for BC Hydro advised the Commission Panel during submissions that BC Hydro had returned, unopened, Calpine’s bid as to price. Calpine chose to not file its bid with the Commission.

2.1.2 Disqualification Applications

At the December 22, 2004 Pre-hearing Conference, GSXCCC and BCSEA made an application for an Order that Commissioner Birch, a member of the Commission Panel established to consider the EPA filing, be disqualified from participating in the EPA review on the basis of a reasonable apprehension of bias that related to Commissioner Birch’s position as an interim president of the Alliance Canadian and U.S. Pipelines (T4: 598-613).

The GSXCCC and BCSEA also made a second application that Chairman Hobbs be disqualified from participating in the EPA Review for a reasonable apprehension of bias in relation to the decision-making regarding Commissioner Birch’s position on the Panel (T4: 611).

Following submissions from the parties on the applications to disqualify Commissioner Birch and the Chairman, the Commission Panel adjourned. Commissioner Birch recused himself from the Panel and the EPA review and therefore no decision from the Commission Panel was required on the motion to disqualify him. The Chair and Commissioner Boychuk then considered the submissions related to the application to disqualify the Chairman. The Commission Panel dismissed the application with reasons to follow (T4: 683). The Reasons were provided in Appendix A to Commission Letter No. L-10-05 dated February 9, 2005.

By letter dated January 23, 2005 (Exhibit C20-35), GSXCCC et al. applied for an Order that the Commission Panel disqualify itself on the grounds of a reasonable apprehension of bias and denial of procedural fairness and natural justice during the hearing, specifically in relation to the *in-camera* session conducted on January 19, 2005. On January 27, 2005, the Commission Panel dismissed the application with reasons to follow (T14: 2882). The Reasons were provided in Appendix B to Commission Letter No. L-10-05 dated February 9, 2005.

2.2 Treatment of Confidential Information

The Commission Panel's approach to the handling of confidential information proved to be one of the continuing and controversial issues in the proceeding. The handling of confidential information first surfaced at the November 29 and 30, 2004 Procedural Conference, where the Commission Panel accepted BC Hydro's proposal regarding confidentiality. The proposal allowed for an intervenor to have access to the QEM model, exclusive of the data relating to each bid, provided the intervenor asked for access and signed a confidentiality agreement. It appears that, at least, the JIESC signed such an agreement and received access to the QEM model (T6: 1305). Green Island, a bidder in the CFT process, also had access to the QEM model. The Commission Panel's comments on its proposed treatment of confidential information became the subject of applications by BCOAPO and the JIESC for reconsideration which culminated in Order No. G-119-04 dated December 24, 2004, followed by Reasons for Decision issued January 6, 2005 (Exhibits A-16 and A-19 respectively). The Reasons for Decision relating to Order No. G-119-04 explains the Commission Panel's views on confidentiality in the context of this proceeding.

This section of the Decision discusses how the Commission Panel received and collected confidential information during the proceeding. Where the confidential information has been specifically used by the Commission Panel to arrive at the Decision, the Commission Panel's reliance on the confidential information is the subject of discussion elsewhere in the Decision. This section is divided into two parts: the first relates to the manner by which confidential information was received prior to the oral hearing, and the second to the manner by which confidential information was obtained during the oral hearing.

2.2.1 Confidential Information Received Prior to the Oral Hearing

Prior to the oral hearing the Commission Panel received copies of the EPA, the VIGP Transfer Agreement, and the QEM model and input data (Confidential Exhibits B-4, B-5). The Commission Panel also used Information Requests that were sometimes, in part, confidential, to obtain confidential information. The responses to those Information Requests are found in Confidential Exhibits B-10, B-15, B-17, B-24, B-37 and B-51. The Commission also received confidential information from Green Island (Confidential Exhibits C9-13, C9-14 and C9-19).

While BC Hydro originally claimed confidentiality for Appendix 3 to the EPA, Commission Order No. G-119-04 required the disclosure of Appendix 3 except for subsections 1.1(hh), 1.1(ii) and 1.1(jj). BC Hydro filed a copy of Appendix 3 of the EPA from which only these subsections had been redacted (Exhibit B-19). On January 11, 2005, DPP agreed to the disclosure of the remaining portions of the EPA except for the portions of Appendix 3 ruled confidential, Section 1.7-1.10 of Appendix 5 at pages 75-76 relating to customer specific interconnection facilities, and Appendix 9 at page 89 relating to Dispatch Terms and Conditions which was linked to the Commission Panel's confidentiality ruling on Appendix 3 (Exhibit C17-8).

2.2.2 Confidential Information Received During the Oral Hearing

During the oral hearing the Commission Panel received confidential information both orally and in writing. The means used to obtain the confidential information orally was through the *in-camera* session held with BC Hydro Panel 2 on January 19, 2005. A transcript was kept for that session and following review of the transcript by Commission counsel, counsel for BC Hydro and then the Commission Panel, a redacted version of the transcript was released on January 21, 2005. The redactions related to information that would disclose the names of the parties, or projects, or rankings and the future negotiating positions of any parties in the event future negotiations became necessary (T10: 2267-2268). On January 24, 2005, following the agreement of counsel for DPP and further review of the redacted transcript by Commission counsel, counsel for BC Hydro and the Commission Panel, a virtually complete transcript from the *in-camera* session was released to all participants. The only part of the original transcript not disclosed covers some seven lines at T8: 1744 which relates to a potential negotiating position of BC Hydro (T12: 2516).

Beginning at T14: 2883 and more specifically at T14: 2885-2886, the Panel Chair allowed intervenors to make any procedural requests that they had arising from matters raised in the *in-camera* session. Only counsel for GSXCCC et al., Mr. Andrews, made such a request. At T14: 2887-2888, Mr. Andrews requested that Ms. Hemmingsen be recalled and at T14: 2900, he more fully identified the reasons for his request as follows:

(i) to confirm and explain whether it is true that DPP [plant] without duct-firing is not the most cost effective option for meeting capacity shortfall on Vancouver Island;

(ii) to ask whether it is true that it is her opinion that DPP [plant] with duct-firing is the most cost effective option for meeting the perceived shortfall on Vancouver Island; and

(iii) to ask questions arising from her responses to those issues.

Only two intervenors [BCOAPO and the Village of Gold River ("Gold River")] spoke to the motion. Both were opposed on the basis that the evidence being sought was already on the record (T14: 2901-2902). Counsel for BC Hydro also opposed the motion, but on two grounds: first on the basis that the evidence was already on the record; and second, that the evidence sought with respect to item (ii) of the motion was beyond the scope of the proceeding and beyond the jurisdiction of the Commission Panel in respect of the EPA before the Commission (T14: 2902-2903). The Commission Panel denied the motion.

The Commission Panel also notes that a number of the intervenors [GSXCCC et al., Green Island, Gold River, BCOAPO, Commercial Energy Consumers of British Columbia ("CEC"), NorskeCanada Ltd. ("NorskeCanada") and Shadybrook Farm] referenced the *in-camera* session transcript in their Argument to support their positions that the Commission Panel should not approve the EPA.

As for confidential information received in writing during the hearing, it became apparent during the preparation of these Reasons that certain non-Confidential Exhibits that BC Hydro filed with the Commission also included confidential responses. For the purpose of the record, these confidential responses have been identified as separate Exhibits. The Chair at T7: 1596 requested a document showing the chronology of CFT bidders and projects. The response to this request is a table that is a confidential attachment to part (b) of the response in Exhibit B-79. The table is identified as Confidential Exhibit B-79A.

At T10: 2203-2205, the Chair requested an update of several items based on the December 2004 Load Forecast which resulted in several confidential and non-confidential filings. The update to Attachment A to Appendix J in Exhibit B-1 is in Exhibit B-99, while the spreadsheets used to produce the updated

Attachment A were provided to the Commission in confidence and are identified as Confidential Exhibit B-99A. An updated response to Commission Information Request 1.14.2.3 was filed on a confidential basis as referenced in Exhibit B-100, and is identified as Confidential Exhibit B-100A. Updated responses to Commission Information Requests 1.15.5 and 2.73.1 were filed as Confidential Exhibit B-102.

Commission counsel asked a limited number of questions requiring confidential responses from BC Hydro Panels 2 and 4. These questions, absent certain confidential numbers, form part of the public record. Confidential Exhibit A-41 contains the confidential numbers in Commission counsel's questions to BC Hydro Panel 2. The answers to those questions are found in Confidential Exhibits B-95 and B-96. The answers to Commission counsel's confidential questions to BC Hydro Panel 4 are found in Confidential Exhibits B-93 and B-94.

In addition, Mayor Lewis, on behalf of Gold River, asked BC Hydro questions on the public record regarding a different QEM scenario that represented the Tier 2 portfolio totalling 122 MW of capacity, which resulted in a confidential response. That response is found in Confidential Exhibit B-103.

By letters dated January 17, 2005, counsel for BC Hydro provided counsel for the JIESC, GSXCCC et al., Green Island, and Ms. McLennan with advance notice of witness evidence (Exhibits B-56, B-57, B-58 and B-59). Each letter describes the attachment to that letter as a summary table which provides expected answers to certain questions delivered by the recipient of the letter to BC Hydro which had not been responded to in writing. The attachment to each letter appears to have been intended as an aid to cross-examination for counsel in receipt of it. The attachment was marked confidential in each instance. Apart from the attachment to Exhibit B-57, which was expanded upon in Exhibit B-104, the Commission Panel has not been provided with copies of the attachments to Exhibits B-56, B-58 and B-59.

2.3 Reviews under Section 71 of the UCA

The EPA was filed pursuant to section 71 of the UCA. A filing pursuant to section 71 neither requires a hearing nor approval. Nevertheless, the Commission does have the authority to determine, following a hearing, that the EPA is not in the public interest and to declare the contract or portions of it unenforceable or make any other order it considers advisable in the circumstances.

The Commission Panel established a hearing process pursuant to subsection 71(2) to review the EPA. Having determined that a hearing was appropriate, the Commission Panel exercised its discretion to determine the nature of the process and the issues and evidence it considered necessary to determine whether the contract was in the public interest. On November 30, 2004, after submissions from parties, the Commission Panel established the scope for the issues that it concluded needed review.

The EPA raises many important public interest considerations that were previously the subject of the VIGP Decision and that are addressed in these Reasons for Decision. Although the EPA was the outcome of the CFT process, the Commission Panel accepts the view expressed by some intervenors that the EPA should not be accepted merely to uphold the CFT process. However, the Commission Panel notes that once a competitive market-based process has been undertaken and firm commitments from bidders have been obtained, a competitive process should, in most circumstances, be accepted as persuasive evidence of the cost-effectiveness of the resultant successful bid.

Although the Commission has the authority to "make any order it considers advisable in the circumstances" [section 71 (3)(b)], the Commission Panel accepts in these circumstances that it does not have the authority under section 71 to impose terms or alter the filed EPA. Accordingly, it does not have the authority in this instance to approve the DPP bid with duct-firing, nor to create a contractual commitment that would require DPP to make the duct-firing capacity available to ratepayers.

3.0 PEAK DEMAND FORECAST CAPACITY FOR VANCOUVER ISLAND

3.1 Background

The peak demand forecast for Vancouver Island was determined to be relevant for this proceeding. The principal relevance is that the peak load forecast affects the size of the capacity deficiency and in turn affects the relative cost-effectiveness of the three possible CFT outcomes, i.e., the Tier 1, Tier 2 or the No Award alternatives (T1: 44-46; T2: 311).

According to BC Hydro, the load forecast was not employed as an input or a material influence in the CFT process itself. In the QEM the load forecast was not an input (T6: 1076). The Commission Panel notes, however, that the most current demand/supply outlook for Vancouver Island and the BC Hydro system was used in the Cost-Effective Analysis that was reviewed by the Utility's senior management (Exhibit B-1, p. 14; Exhibit B-9, BCUC IR 1.1.2).

Based on evidence related to load forecasts and dependable supply capability adduced in the VIGP proceeding, the Commission determined that for planning purposes BC Hydro should use a capacity shortfall of 116 MW in 2007/08. The Commission's VIGP Decision anticipated that BC Hydro would provide an additional buffer above the 116 MW required in 2007/08 to reach an aggregate dependable capacity of at least 150 MW (VIGP Decision, pp. 26, 83).

In the intervening period, BC Hydro has had the opportunity to: 1) re-establish its design temperature; 2) incorporate the impact of the increase in the peak sensitivity to temperature based on temperature and peak data obtained in F2004;[1] 3) update the economic input assumptions; and 4) modify its forecasting methodology and estimates in Power Smart savings (Exhibit B-67, p. 50; Exhibit B-9, BCUC IR 1.4.1; Exhibit B-104, p. 2).

BC Hydro concludes that the gap between the peak demand experienced in the Vancouver Island region and the supply resources available to meet the demand has grown considerably since the VIGP Decision (BC Hydro Argument, p. 24). The Commission Panel notes that the increase in deficit in the demand/supply balance on Vancouver Island since the VIGP Decision can be attributed largely to the significant change in load forecast rather than a major change in supply capability (Exhibit B-9, BCUC IR 1.4.1, 1.43.1).

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[1] Dates marked with an 'F' refer to BC Hydro's fiscal year, which ends March 31.

3.2 Load Forecasts and Capacity Deficit

BC Hydro forecasts that the capacity deficit on Vancouver Island will rise from 37 MW in F2007 to 280 MW in F2008. This jump of 243 MW is a result of the de-rating of the High Voltage Direct Current ("HVDC") transmission system (240 MW) and an increase in load requirement (4 MW) after taking into account Power Smart and transmission losses (Exhibit B-98).

BC Hydro explained that the supply deficit of 280 MW was raised from 262 MW in the original filing as a direct result of the revised load forecast, which was updated to reflect the decision of the Commission with respect to a rate increase of 4.85 percent instead of the assumed rate increase of 8.9 percent effective April 2004 (T9: 1893-1894; Exhibit B-67 cover letter). BC Hydro revised the peak demand forecasts through the use of Monte Carlo simulations for no rate increase and approved rate increase. The overall peak demand response was assumed to be 75 percent of the percentage difference in energy responses calculated from the two simulated model runs and reflects a reduced price sensitivity of demand during average cold weather (Exhibit B-16, BCUC IR 2.45.1).

The actual recorded peak load in F2004 and F2005 and the peak demand forecasts for selected years F2005 to F2008 and F2016 are shown in Table 3.1 below:

Table 3.1

BC Hydro Peak Demand Forecasts for Vancouver Island

(MW)	F2004 (Actual)	F2005	F2006	F2007	F2008	F2016
2004 Load Forecast	--	2,256	2,260	2,275	2,279	2,556
2004 Revised Load Forecast	--	2,269	2,277	2,293	2,297	2,577
Actual Recorded Peak	2,253	2,317	--	--	--	--
Weather Adjusted Peak	2,210	2,297	--	--	--	--

Note: The peak demand forecasts include Power Smart and transmission losses
Source: Exhibit B-12, GSXCCC IR 1.28.1; Exhibit B-98; Exhibit B-68

GSXCCC et al. presented evidence regarding load forecasting through a report prepared by Mr. Miller (Exhibit C20-21; Exhibit C20-37). Mr. Miller examined the BC Hydro forecast methodology to identify apparent flaws, measured the performance of BC Hydro's modelled outputs to assess reliability, and provided a set of intuitive load forecasts based on population and employment forecasts (Exhibit C20-21, p. 5).

From his analysis, Mr. Miller concluded, among other things, that the employment forecast used by BC Hydro (i.e., the R.A. Malatest projections) is inconsistent with the population numbers from the BC Statistics Regional Health District. Mr. Miller argued that if those sets of numbers were to co-exist, the unemployment rate on Vancouver Island would have to drop by more than half (T14: 2907; Exhibit C20-36; Exhibit B-104, p. 2).

BC Hydro argues that the GSXCCC et al. assertion that the employment forecast data used by BC Hydro requires that the unemployment rate to be cut roughly in half is unsubstantiated or explained (BC Hydro Reply, p. 15).

The Commission Panel notes that between calendar years 2004 to 2009, population on Vancouver Island is projected to grow from 698,000 to 720,000, an increase of 22,000, and for the same period employment is projected to grow from 303,000 to 328,000, an increase of 25,000 (Exhibit B-104, p. 2). Since the employment growth is higher than the population growth, and since not all the forecast net increase of population is available to increase employment (Exhibit C20-36, p. 2), the BC Hydro employment forecast does imply a reduction in the unemployment rate on Vancouver Island.

Mr. Miller updated the employment-based forecast in order to include the most recent load information that BC Hydro released during the proceeding (T14: 2909). The alternative forecasts by Mr. Miller are presented in Table 3.2 below:

Table 3.2

Peak Demand Forecasts for Vancouver Island by Mr. Miller

As labeled in C20-21	FY 2004	FY 2005	FY2006	FY 2007	FY 2008	FY2016
As labeled in C20-37	04/05	05/06	06/07	07/08	08/09	16/17
Population-based Forecast (MW)	2,053	2,061	2,072	2,086	2,100	2,256
Employment-based Forecast (MW)	2,169	2,148	2,167	2,186	2,206	2,360
Updated Miller Forecast (MW)	2,317	2,206	2,234	2,261	2,288	2,507

Source: Exhibit C20-21; Exhibit C20-37

The Commission Panel notes that the difference between BC Hydro's peak demand forecast for F2008 and Mr. Miller's forecast for 2007/08 is 36 MW (2,297 minus 2,261).

3.3 Arguments on Peak Load Requirements and Demand/Supply Balance

BC Hydro submits in Argument that the successive record peaks in F2004 and F2005 of 2,253 MW and 2,317 MW are examples of the growth in peak demand. Temperatures had been around the average cold day design temperature of -3.6 degrees when the F2004 and F2005 peak loads were recorded (at - 4.7 degrees Celsius and - 4.1 degrees Celsius respectively). BC Hydro argues that the recent weather data have made clear that the forecasts of Mr. Miller as filed by GSXCCC et al. are inadequate. In BC Hydro's view, Mr. Miller's use of a short historical period of ten years and his use of actual load has resulted in significant underestimated demand of foreseeable peaks (BC Hydro Argument, pp. 24, 25).

DPP submits that there has been an increase in capacity deficit since the time of the VIGP Decision and agrees that this increase reinforces the need for on-Island generation. DPP further submits that both British Columbia Transmission Corporation ("BCTC") and BC Hydro should consider the load shifting demand management proposal be kept for contingency events rather than treat the proposal as a long-term planning solution (DPP Argument, pp. 2, 17).

Mr. McKechnie states that he understands and agrees with BC Hydro and DPP that Vancouver Island has an immediate capacity problem. However, he submits that it is only a short-term problem which will disappear when the new 230 kV transmission is in place by 2008 or 2009 (McKechnie Argument, p. 1).

In Argument, CEC submits that BC Hydro's 2003 [sic] Load Forecast used in the CFT evaluation does not include impacts from rate changes and demand-side activities. CEC submits a list of examples that BC Hydro had not incorporated and argues that "three of those activities can be planned, installed, commissioned and operated to reduce customers' load requirements without BC Hydro even knowing!" (CEC Argument, p. 24).

The Commission Panel notes that CEC's list of examples under load forecast includes impacts from supply capability such as Resource Smart and Customer Based Generation. The Commission Panel also notes that CEC has not revealed which three activities it was referring to in the list of examples.

Mr. Andersen, in Argument, provides information on various economic indices and their use and various means to reduce use during peak periods (Andersen Argument, pp. 2, 3).

In Argument, Green Island observes that a common theme in BC Hydro's evidence is that the Vancouver Island load forecast has been increasing. Green Island argues that the consequences of increasing load forecast, if considered at all, should have been reflected in the CFT. It submits that raising concern about a rising load forecast only after the CFT is unhelpful because it does nothing to confirm the appropriateness of the Tier 1 outcome determined in the express absence of considering the rising peak load demand (Green Island Argument, p. 14).

The Commission Panel notes that while BC Hydro takes the position that the load forecast was not employed as an input, was not a material influence in the CFT process itself, and was not an input in the QEM model, senior management who reviewed the Cost-Effectiveness Analysis did use the then most current demand/supply outlook for Vancouver Island and the BC Hydro system to assess the three possible CFT outcomes (Exhibit B-1, Appendix J; Exhibit B-9, BCUC IR 1.1.1).

GSXCCC et al. submits that the costs of over-estimating peak load should not be preferred over the costs of under-estimating peak load. GSXCCC et al. takes the position that using weather normalized peak load data is equivalent to using employment normalized peak load data (Exhibit C20-32, BCUC IR 9.1). GSXCCC et al. describes the forecast by Mr. Miller as a "reality check" on the BC Hydro forecast and concludes that BC Hydro's forecasts have an upward bias. GSXCCC et al. argues that since BC Hydro does not attempt to claim any of the underlying factors have changed when presenting the first 15 days of January 2005 recorded load requirements in Exhibit B-68, the variation of the 2005 actual from the 2005 forecasts is a random event (GSXCCC et al. Argument, pp. 11, 13).

BC Hydro submits that it compares its forecast to weather adjusted peaks and this is a standard utility technique. BC Hydro argues that the 2004 Load Forecast was undertaken without the benefit of any information with respect to January 2005 actual loads. The fact that the 2004 Load Forecast on peak demand accurately predicted what would happen at design day temperatures does not challenge the forecast but rather confirms it (BC Hydro Reply, p. 16).

The Commission Panel accepts that comparing weather-adjusted data to analyze peak load demand is a standard technique. It notes that the record peak load requirements in F2004 and F2005 had occurred close to the design temperature (Exhibit B-68). Since the design temperature is established to measure the expected maximum amount of electricity consumed in a single hour under an average coldest day assumption, the Commission Panel is reluctant, in the absence of any major changes in the underlying factors, to view the record demand as a random event.

In Argument, the JIESC submits that the peak demand is highly variable and a new demand is not determinative of higher demand in subsequent years (JIESC Argument, p. 4).

The Commission Panel agrees with the JIESC’s observation that a new demand is not determinative of higher demand in subsequent years. The Commission Panel accepts that, for example, changes in socioeconomic factors could affect the forecasts in subsequent years. However, as noted by GSXCCC et al., BC Hydro has not claimed that there have been any changes in the underlying factors that created the new demand in the first 15 days of January.

Mr. Hill argues that all that has happened since the VIGP hearing is a spike (Hill Argument, p. 6).

Mr. Steeves, in Argument, repeats the concerns he had expressed during his cross-examination of Panel 4 with respect to the lack of variation in the growth assumptions used by BC Hydro as presented in Table 4.2 of the Revised 2004 Load Forecast (T9: 2114-2115; Exhibit B-67, p. 11). Mr. Steeves argues that since these input values have “no variations and no uncertainty”, BC Hydro’s model of the world is unreal (Steeves Argument, Addendum A, pp. 6, 7).

The Commission Panel acknowledges Mr. Steeves’ observations but finds that the growth assumptions in Table 4.2 of the Revised 2004 Load Forecast are presented in terms of percentage changes to demonstrate expected long-term growth trends, not year-to-year variability around those long-term trends.

Ms. McLennan supports Mr. Miller's position that BC Hydro has over-estimated employment forecasts based on the employment versus population increases identified in Mr. Miller's Argument (McLennan Argument, p. 3). In Argument, Ms. McLennan presents two possible planning shortfall figures: 54.5 percent of 280 MW or 152 MW, and 75 percent of 280 MW or 210 MW.

The Commission Panel is unable to assess the 152 MW or 210 MW deficiencies as neither the figures nor the assumptions used to calculate these figures have been previously presented in the interrogatory or cross-examination phases of the hearing.

NorskeCanada does not dispute that there may be a capacity shortfall on the Island in 2007/08 but expresses concern about the stated magnitude and the duration of the shortfall (NorskeCanada Argument, pp. 3, 4). NorskeCanada argues that the magnitude of change from 116 MW to 280 MW in less than one and a half years represents an increase of 250 percent [sic] and leads to questions regarding BC Hydro's forecasting methodology. NorskeCanada also argues that the new forecast from BC Hydro that results in a new shortfall of 280 MW has apparently incorporated the impact of recently approved rate increases, changes in methodology and changes in economic assumptions. NorskeCanada commends the evidence of Mr. Miller (NorskeCanada Argument, p. 12).

The Commission Panel notes that the magnitude of change for the capacity shortfall from 116 MW to 280 MW is 141 percent and this can be compared to 66 percent (193 MW vs. 116 MW) from Mr. Miller's evidence. The Commission Panel also notes that the revised forecast that has increased the capacity shortfall on Vancouver Island from 262 MW to 280 MW was, according to BC Hydro, due solely to the new rate filing to reflect the final approved rate increase of 4.85 percent rather than the assumed rate increase of 8.9 percent effective April 2004 (T9: 1893; Exhibit B-67 cover letter; Exhibit B-16, BCUC IR 2.45.1). This representation by BC Hydro has not been questioned or challenged in this proceeding.

Mr. Young observes that the coldest temperature in the last 40 years is -13.05 degrees Celsius and that a 354 MW capacity increase would be required to meet the 40 years' coldest weather. Mr. Young concludes that BC Hydro did not do realistic forecasting (Young Argument, pp. 2, 3).

The Commission Panel notes that BC Hydro uses the average of the coldest daily average temperature of the most recent 30 years instead of 40 years and that the peak demand forecast is based on normal temperature which is defined as -3.6 degrees Celsius (Exhibit B-67, p. 50). This re-established design temperature as used by BC Hydro has not been successfully challenged during the proceeding.

Ms. Malcolmson, in Argument, uses the 190 MW shortfall as advanced by GSXCCC et al. and concludes that this shortfall can be covered by the NorskeCanada demand-side management proposal of 210 MW along with the announced BCTC cable monitoring upgrades (Malcolmson Argument, p. 4).

TGVI bases its support for the need for on-Island generation on the evidence established in this proceeding that shows the January 2004 and January 2005 successive record high peak demands as being already above the F2008 forecast used in the VIGP Decision (TGVI Argument, p. 2).

3.4 Commission Panel Determinations

The 2004 Electric Forecast (Exhibit B-1, Appendix I, p. 15) highlights the role of forecasting at BC Hydro to include, among others, the need for more frequent, short-term and risk-based forecasting at the regional, or district level. BC Hydro, however, has not carried out a special forecast for the Cost Effectiveness Analysis to review the CFT or a special run to test the sensitivities and measure the risk of the upper and lower bounds of economic growth assumptions (T10: 2187).

The Commission Panel notes that the peak demand model for Vancouver Island is sensitive to projections of economic factors. In the reconciliation of change in deficit between 2003 and 2004 which was 185 MW and 262 MW respectively, economic factors accounted for 29 percent or around 50 MW of the change (T10: 2186-2187). The Commission Panel acknowledges the submission of GSXCCC et al. that BC Hydro’s employment forecast assumption is likely to be inconsistent with population projection and therefore is likely to be overestimated.

The Commission Panel accepts the argument advanced by BC Hydro that the 2004 Load Forecast accurately predicts what would happen at design day temperature and that the January 2005 recorded peak load requirements confirm the forecast from the peak demand model (Exhibit B-68; BC Hydro Reply, p. 16). Based on the weather adjusted peaks recorded for F2004 and F2005, the Commission Panel finds that it is likely that, at design temperature, the peak demand in F2008 could easily reach the vicinity of 2,297 MW as forecast (X-reference Table 3.1) even without further growth in the underlying economic factors as from F2005.

The Commission Panel concludes that the Load Forecast supports the capacity addition of 150 to 300 MW in F2008 which BC Hydro targeted in the CFT.

4.0 CALL FOR TENDERS FOR VANCOUVER ISLAND

4.1 Background

4.1.1 VIGP Decision

During the VIGP hearing, BC Hydro introduced and developed its proposal for a CFT for capacity on Vancouver Island. Pages 39 to 46 of the VIEC Reply Argument in that proceeding was "Schedule A: Call for Tenders" (Exhibit B-1, Appendix A which will be referred to in this Decision as "Schedule A"). After denying the CPCN Application for the VIGP, the Commission made a number of comments in Chapter 9 of the VIGP Decision about the CFT process that BC Hydro had proposed in Schedule A. The Commission also stated:

> "This Chapter includes suggestions for the CFT process, since the Commission Panel accepts that a utility has the initial responsibility to plan for its future resource additions. … It will be BC Hydro's choice whether to proceed with the CFT recognizing that BC Hydro must develop sufficient information to identify the most cost-effective resource addition for Vancouver Island. The results of the CFT would provide valuable information for BC Hydro to discharge its responsibility. The Commission Panel encourages BC Hydro to proceed with the CFT and to closely follow the schedule set forth in Schedule A.
>
> This Decision neither proposes changes to, nor endorses, Schedule A. … The Commission Panel accepts that variations to Schedule A may be necessary. The following comments are therefore intended only as considerations for the design and execution of the process."
>
> (VIGP Decision, p. 79)

The Commission encouraged BC Hydro to proceed with a CFT on the schedule set forth in Schedule A and indicated that, based on the results of the CFT, the Commission was prepared to consider any future applications for CPCN approval or EPA approval on an expedited basis (VIGP Decision, p. 77).

4.1.2 Commission's January 23, 2004 Letter

In a letter dated October 23, 2003, counsel for BC Hydro requested that "…the Commission decide as a preliminary matter whether the terms of the CFT as proposed are appropriate, so that the Panel making the decision on the selected project does not [need to] revisit that issue." BC Hydro proposed a schedule to allow for stakeholder input, including workshops and a comment process following the issuance of its

CFT and requested that the Commission decide by January 15, 2004 "…whether the CFT as designed is appropriate". In its letter dated October 24, 2003, the Commission stated its intention to provide its response on the appropriateness of the terms of the CFT by January 15, 2004.

BC Hydro issued the CFT on October 31, 2003 (Exhibit B-1, Appendix B). The review process provided for workshops, a public forum and opportunities for stakeholder comment and input, including comments to the Commission by January 9, 2004 and a reply submission by BC Hydro on January 13, 2004. By letter dated January 13, 2004, BC Hydro requested Commission approval of the terms of the CFT including the evaluation criteria and methodology, the related documents and the CFT schedule. The filing included copies of Bidder Reply/Comment Forms that had been submitted to BC Hydro and several revised CFT and EPA documents (Exhibit B-1, Appendix D).

The Commission responded by letter dated January 23, 2004 (Exhibit B-1, Appendix F). In the letter, the Commission recognized that the CFT is a process that is to be designed and implemented by BC Hydro. At the same time, the Commission expressed its desire to provide comments that would be helpful to BC Hydro and other participants, with the caveat that the comments would not be determinative of any issue or matter so as to not bind BC Hydro or fetter the Commission when ultimately called upon to consider any CPCN applications and/or EPAs following the CFT process. The Commission proceeded to comment on several issues where stakeholders had expressed concern:

- Scope of the CFT;
- Transmission deferral credit;
- Staged addition of capacity resources;
- Sale of VIGP assets;
- Gas and electricity prices;
- Gas transportation costs; and
- Electrical network upgrade costs.

The Commission also cautioned BC Hydro that it should not expect that a transmission deferral credit would be accepted by the Commission in reviewing the project(s) selected by the CFT. The Commission also made the following general comment about mandatory requirements of the CFT and areas where BC Hydro would make discretionary judgments:

> "The Commission Panel will be concerned if such requirements are more stringent or less flexible than the minimums that are needed, thereby increasing costs for ratepayers by disqualifying otherwise worthwhile projects or by increasing bid prices."

In the January 23 letter, the Commission encouraged BC Hydro to proceed with the CFT, and repeated the statement at page 77 of the VIGP Decision that it was prepared to consider any future application for an EPA on an expedited basis. It went on to state:

> "Approval of the project(s) selected following the CFT process may require a further review of the CFT process and design. As always, the onus of proof will be borne by the Applicant."

Partially in response to the Commission's January 23, 2004 letter, on March 5, 2004 BC Hydro issued Addendum 10 which made several significant changes to the CFT (Exhibit B-1, Appendix G.)

4.1.3 Overview of CFT Process

The following schedule of the CFT process summarizes BC Hydro's extensive communications with stakeholders over the year that followed the release of the CFT on October 31, 2003. There was also an ongoing Question and Answer process whereby information was posted on BC Hydro's web page.

• Issuance of CFT	October 31, 2003
• Registration deadline	November 14, 2003
• Pre-Qualification workshop	November 21, 2003
• Bidder comments on CFT and agreements	December 1, 2003
• Comments from bidders and interested parties	January 9, 2004
• Filing of revised CFT with BCUC	January 13, 2004
• CFT resumed following suspension period	March 5, 2004
• Deadline for pre-qualification submissions	March 29, 2004
• Selection of pre-qualified bidders	April 29, 2004
• Bidders provide final comments on draft agreements	May 21, 2004
• Final form agreements issued	June 23, 2004
• Tender workshop	August 7, 2004
• Deadline for submission of tenders	August 13, 2004
• Announcement of preferred option and EPA award	November 3, 2004

(Exhibit B-1, p. 4)

On April 29, 2004, BC Hydro announced that 11 bidders had pre-qualified for the CFT with 22 projects, which were mostly natural gas-fired. A hydroelectric project and a wood waste project also pre-qualified. Three bidders (a coal plant, a wind farm and a biomass/coal plant) failed to meet the CFT Mandatory Criteria and were disqualified (Exhibit B-1, p. 8). Accordingly, these bidders did not participate further in the CFT process.

By the closure of bids on August 13, 2004, BC Hydro received tenders from six bidders for ten projects. BC Hydro determined that two tenders with three projects should be rejected for non-compliance with CFT requirements. One project was rejected as it did not reflect a pre-approved plant description (Exhibit B-1, Appendix K, Tab 4, p. 8). The six projects in Table 4.1 passed the Submission Evaluation Committee review.

Table 4.1

Tender	Technology	Bid Capacity (MW)
A	Natural gas, duct-fired	280
	Natural gas, non-duct-fired	252
B	Natural gas, duct-fired	285
	Natural gas, non duct-fired	255
C	Biomass	75
D	Natural gas, dual fuel	47

(Exhibit B-1, p. 9; Appendix K, Tab 4, p. 13)

When BC Hydro assembled the projects into all possible portfolios aggregating between 150 and 300 MW of dependable capacity, it found that one of the tenders did not qualify for inclusion in any portfolio as its bid capacity did not conform to the prescribed range of portfolio sizes (Exhibit B-1, p. 13). The winning CFT portfolio was the DPP plant without duct-firing which would supply 252 MW. This bid had a lower net present value cost than the next lowest cost portfolio, and was approximately $100 million lower than the incremental cost of the VIGP benchmark after adjusting the bid for the $50 million payment for the existing VIGP assets.

BC Hydro Senior Management also requested additional analysis to confirm whether the selected CFT portfolio was the most cost-effective solution (Exhibit B-1, Appendix J). This analysis examined three possible CFT outcomes:

- Tier 1 (the preferred outcome for 252 MW as determined by the Quantitative Evaluation Methodology [“QEM”] for the CFT);

- Tier 2 (two smaller projects totalling 122 MW); and
- No Award.

On November 3, 2004, BC Hydro announced that the preferred CFT option is a 252 MW gas-fired project tendered by Duke Point Power (Exhibit B-1, p. 19). On November 19, 2004, BC Hydro filed the EPA with DPP in accordance with section 71 of the Act.

4.2 Independent Reviewer

4.2.1 Proposed Role of Independent Reviewer

Independent Reviewers are typically used in calls for tenders where the party issuing the call is potentially in a conflicted position. During the VIGP proceeding, concerns were expressed about the role of BC Hydro as both a potential project proponent and as the selector of the preferred project and the buyer of the product (VIGP Decision, p. 80). In the CFT, BC Hydro also provided an option for bidders to purchase the VIGP assets. Hence, a perception of conflict of interest could arise.

The Commission, in the VIGP Decision, encouraged BC Hydro to utilize an Independent Reviewer according to the terms of Schedule A from the VIGP proceeding, which is Appendix A of the CFT Report, and suggested that the Independent Reviewer report to a Commissioner who would not sit on any panel to consider a selected resource alternative. BC Hydro subsequently retained Pricewaterhouse Coopers LLP ("PwC") as the Independent Reviewer for this CFT and chose not to avail itself of the option of having PwC report to a Commissioner.

4.2.2 Terms of Reference for PwC

In the CFT issued on October 31, 2003, the Independent Reviewer Terms of Reference defined the first role of the Independent Reviewer in this CFT as "Review and report on the fairness of the CFT terms before issue (Initial Report)" (Exhibit B-1, Appendix B, Appendix 9; "Terms of Reference"). The CFT was issued more than two months after PwC began its assignment as Independent Reviewer on August 21, 2003 (Exhibit B-1, Appendix K, Tab 1, Backgrounder). The PwC "Fairness Framework" refers to "Commercial Terms" as a "key sub element" of the "Competitive" element of the Fairness Framework (Exhibit B-1, Appendix K, Tab 4, Appendix B). Mr. Hodgson of BC Hydro's Panel 3 agreed that the EPA terms fall under the umbrella of the "CFT terms" (T8: 1874).

Exhibit B-1, Appendix K contains the four main reports of the Independent Reviewer. Mr. Sorenson, also of BC Hydro’s Panel 3, agreed that none of the four reports commented on the CFT terms as required in the Terms of Reference (T8: 1874-1875). Furthermore, the footnote on page 3 of the fourth (and final) report indicates that PwC made an “interpretation” of the requirements of this role. The original requirement “Review and report on the fairness of the CFT terms before issue” in the Terms of Reference became “CFT process design, evaluation framework design and timelines”. Mr. Sorenson confirmed that this interpretation process took place (T8: 1875-1876). The requirement to report on the fairness of the CFT terms (and by inclusion the EPA terms) was thus eliminated from PwC’s role.

When asked if a responsibility of the Independent Reviewer was to ensure that BC Hydro reasonably sought to put all the bidders on equal footing with regard to the terms and conditions of the CFT, Mr. Hodgson stated “With respect to process? Yes.” (T8: 1790-1791).

Mr. Sorenson’s understanding of the role of the Independent Reviewer is that “We were not hired to consult, to advise or to suggest. It was to observe and comment where appropriate, and for Hydro to deal with it” (T8: 1868). Another BC Hydro Panel 3 member, Mr. Cender, agreed that PwC did not act as “an advisor or a consultant” (T8: 1871-1872). Under such circumstances, it is not clear to the Commission Panel how the Independent Reviewer could have fulfilled its first role as originally defined in the Terms of Reference.

A second area where the role of the Independent Reviewer changed relates to the ability of bidders to communicate with the Independent Reviewer. Section 7.3 of Schedule A provided for bidders to talk to the Independent Reviewer in workshop sessions in the absence of BC Hydro representatives. At some point, a decision was made to prohibit independent contact between bidders and the Independent Reviewer, as per Section 18.20 (“No Lobbying”) of the October 31, 2003 CFT (Exhibit B-1, Appendix B). Breach of this requirement could result in bidder disqualification under Section 18.24 of the CFT.

The evidence for this change in approach is somewhat unclear. The response to BCUC IR 2.70.3 in Exhibit B-16 indicates the Independent Reviewer requested the prohibition, apparently in order to minimize the risk of “…tainting the impartiality of the Independent Reviewer”. In the hearing, BC Hydro characterized it instead as a “mutually desirable outcome” (T8: 1880). Mr. Sorenson agreed with Commission counsel’s characterization of the requirement as an “asymmetrical prohibition”, in that the Independent Reviewer could speak privately with BC Hydro representatives, but not with bidders (T8: 1879).

4.2.3 Views of the Participants

BC Hydro and DPP referred to the Independent Reviewer variously as having affirmed, accepted, endorsed or confirmed various decisions or actions of BC Hydro (T6: 1229; T7: 1425, 1436, 1444, 1540; DPP Argument, pp. 5, 7, 8). Various intervenors express concern that the Independent Reviewer's scope was confined only to process (CEC Argument, pp. 2, 6, 7; JIESC Argument, p. 13). Intervenors argue that the scope excluded opining on the substance and did not provide an evaluation of bias or unfairness in the substantive elements of the CFT criteria and EPA terms and conditions. The JIESC quotes from the Independent Reviewer's fourth report:

> "Our scope of our work did not include review of any matters related to BC Hydro's stated purpose for the CFT from a business, rate payer or regulatory perspective."
>
> (JIESC Argument, p. 13; Exhibit B-1, Appendix K, Tab 4, p. 3)

Green Island expresses concerns about lack of definition and fairness in the decision rules related to the privative clause, and is critical of the performance of BC Hydro and the Independent Reviewer in this area (Green Island Argument, p. 10).

4.2.4 Commission Panel Determination

The Commission Panel acknowledges BC Hydro's use of an Independent Reviewer to address the potential conflict identified in the VIGP proceeding and recognizes the substantial cost and effort involved to do so. However, the Commission Panel has a number of concerns, and would expect significant improvements if an Independent Reviewer is used in future CFTs.

Elimination of First Independent Reviewer Role

A successful CFT requires not only a fair, transparent, and competitive process, but also requires that the underlying terms and conditions of the CFT, including the EPA and any other agreements, are appropriate for the circumstances. For example, if the terms and conditions of a CFT were unduly stringent, the CFT might well produce the most cost effective result from among those bidders who met mandatory requirements and elected to bid. However, as cautioned in the Commission's January 23, 2004 letter, other potential bidders might be disqualified or discouraged from bidding into such terms and conditions. Hence, the degree of competition could be unjustifiably reduced. In addition, the successful bidder presumably would price such requirements into the tender, with a resultant unjustified premium to ratepayers. DPP acknowledged both potential results of variations in stringency of EPA terms and conditions (Exhibit C17-13, BCUC IR 1.9.3, 1.9.4).

CFT terms include the terms and conditions of the EPA and any other material agreements required of bidders, and also the interpretation and application of the CFT terms. Unfairness to bidders in the sense of harsh or overly stringent application of terms and conditions will ultimately act to the detriment of ratepayers in the competitive process. The converse (unduly "soft" application of terms) is also undesirable, as acknowledged by Ms. Van Ruyven (T6: 1196). These considerations must be accommodated in designing future guidelines for the application of CFT terms.

The Commission Panel notes that the task of reviewing and reporting on the fairness of the terms of the CFT was not undertaken in this CFT, contrary to the original Terms of Reference for the Independent Reviewer. There does not appear to be satisfactory evidence as to the rationale for, and explanation of, the elimination of this role, nor apparent clear disclosure of the action. The role of the Independent Reviewer was, as described by intervenors, restricted to considerations of fairness concerning the process and application of the CFT terms. **The Commission Panel considers that the Independent Reviewer could have potentially played a more meaningful role by evaluation the fairness of the CFT term, but accepts that the actual role was helpful to BC Hydro and of some limited effectiveness to address the potential conflict issues.** In its ruling on November 30, 2004, the Commission Panel determined that "the issue as to whether or not BC Hydro conducted the CFT in accordance with its terms is not an issue for this review" (T2: 314).

In future CFTs involving Independent Reviewers, the Commission Panel will expect BC Hydro to clearly communicate to stakeholders the scope, role, or responsibilities of an Independent Reviewer and any proposed changes. As well, BC Hydro may wish to consider whether specialized areas like terms and conditions of EPAs might be reviewed by experts in conjunction with stakeholders prior to the CFT.

<u>Communications with Independent Reviewer</u>

The Commission Panel is not persuaded by the identified justification for the "asymmetric prohibition" in the Independent Reviewer's relationships - that Independent Reviewer/bidder communication in workshops without the presence of BC Hydro representatives could taint the Independent Reviewer. If this claim were to be accepted, given the frequent and ongoing contact of the Independent Reviewer with

BC Hydro in the CFT and potentially other activities, then the logical outcome might be to have the Independent Reviewer report to an independent third party.

Value of Independent Reviewer Role

Given the elimination of the first role of the Independent Reviewer in this CFT and its ultimately more limited role, the Commission Panel questions the net value added by the Independent Reviewer in this CFT, particularly given the cost of approximately $1 million (Exhibit B-18, Gold River IR 1.5.31). Furthermore, there may be less justification for an Independent Reviewer for future CFTs where BC Hydro is not in the dual role of electricity buyer and owner of assets that may be transferred to a proponent as part of the CFT process (or potentially developed as a utility generation project).

If BC Hydro believes that an Independent Reviewer would be helpful and should be used in a future CFT, the Commission Panel suggests that BC Hydro solicit the views of stakeholders and report to the Commission, prior to future CFTs, on the proposed circumstances, terms of reference and communication protocols under which Independent Reviewers would be used. BC Hydro is also encouraged to determine if optional CFT structures are available to avoid the potential conflict of interest that leads to the need for an Independent Reviewer and to consider other options to provide fairness and transparency.

4.3 Issues Regarding the CFT

4.3.1 Resource Bias - Fuel Cost Risk

Prior to the start of the hearing, the Commission Panel determined that all CFT criteria that are relevant to the selection of Tier 1, Tier 2 and the No Award alternatives, and the implications of the CFT criteria for certain resources, are within the scope of the proceeding. The Commission Panel also stated that, as relevant to the Principal Issue for the proceeding, resource option design bias is an issue (T2: 312, 314). This issue was anticipated by the Commission's statement at the end of the VIGP Decision:

> "The Commission Panel believes that it is important that the CFT be perceived as fair and open so that projects other than VIGP with GSX supply compete on a level playing field to meet the load requirements of Vancouver Island."
>
> (VIGP Decision, p. 84)

The CFT provided gas tolling options for gas-fired projects whereby BC Hydro would be responsible for providing gas to fuel the plant, and also, if selected by the bidder, transportation of the gas to the plant. BC Hydro accepted this responsibility on the basis that it is in a strong position to cost-effectively manage gas supply and its costs, and to effectively mitigate any exposures within its existing portfolios and procurement activities (Exhibit B-1, pp. 3, 12). BC Hydro has a portfolio of gas requirements and transportation, a portfolio of electricity purchase and sale requirements, and a transaction infrastructure through Powerex that it can use to access spot and forward markets for gas. An individual proponent that supplied its own fuel would need to buy long-term fixed price gas in an illiquid market and incur risk premiums. BC Hydro felt this would be difficult for proponents to do given concerns about utilization factor (T7: 1541). BC Hydro stated that the tolling option benefits gas-fired proponents by giving them more options to bid, allowing them to bid projects that have lower utilization. In particular, it permits bids from proponents of smaller peaking projects, since it would be very difficult for them to bid on a fixed price basis (T7: 1530, 1548). BC Hydro felt there were benefits to both proponents and ratepayers, but was unable to quantify them (T7: 1541).

Under the CFT Fuel Supply Certainty Guidelines, non-tolling gas-fired bidders and biomass-fueled bidders were required “to demonstrate that the bidders’ fuel arrangements or strategies were sufficient to satisfy its fuel requirements assuming the project is operated at Bid Capacity” (Exhibit B-16, BCUC IR 2.49.3; Exhibit A-40). BC Hydro clarified that under the CFT it would make an assessment whether or not a bidder had secured, or can secure, sufficient firm and non-firm transportation arrangements and on-site storage for the primary and alternative fuels (T8: 1691). BC Hydro sought to apply the same standards for fuel transportation risks for tolling bids as for non-gas-fired projects and would have applied the same standards for non-tolling gas-fired bids (T8: 1709).

In its Argument, BC Hydro states that it offered to assume price risk for natural gas but not for other fuels in an effort to support active competition and to ensure a cost-effective outcome for ratepayers by allocating risks to the parties best able to bear them. BC Hydro desired a process that attracted healthy competition, but not one that would necessarily be equally attractive to all bidders. The Utility felt that proponents might include unreasonably high premiums in their bids if they were required to assume price risk for natural gas (BC Hydro Argument, p. 15). BC Hydro acknowledges that the tolling option introduces a risk that is not present with non-gas-fired options, but argues that it also provided flexibility to manage the dispatch of the plant, compared to a fixed-price take-or-pay arrangement, and so prevented the risk of regret when gas prices are lower than forecast (BC Hydro Argument, pp. 15, 16). DPP makes similar arguments, but acknowledges that this did not apply if the plant was needed for operational purposes (DPP Argument, pp. 6, 7).

Green Island argues that all bidders in the CFT were not on an equal footing and submits that the cost-effectiveness of the DPP plant cannot be determined with any reasonable level of confidence. It states that the CFT should have required gas project bidders to submit two bids, including one where BC Hydro did not assume the fuel risk, in order to obtain a market value for the benefit to gas project bidders of the tolling option. That would have provided a basis for including a credit in the evaluation of non-gas projects. Green Island goes on to state that fuel supply uncertainty and performance risk prevented it from bidding additional project phases totalling more than 150 MW. Green Island argues that the fact that it was the only final bidder that was responsible for its own fuel and transportation costs is proof of resource bias (Green Island Argument, pp. 15, 16).

The JIESC also considers this issue to be an example of resource bias, and notes that BC Hydro did not endeavour to find out what the price for electricity would be if proponents had been required to accept gas price and transportation risks. The JIESC argues that the bids for gas-fired projects would have been much higher because the risks are substantial, and notes that BC Hydro had not made any risk adjustments in its analysis to compensate for this. The JIESC argues that while BC Hydro may be able to hedge the short-term gas price risk, it cannot hedge certain long-term risks (JIESC Argument, pp. 14, 16). BC Hydro disagrees with the conclusion that the cost of gas price risk to BC Hydro ratepayers would be high, since its expectation of a substantial premium results from bidders' inability to manage this risk. BC Hydro already has a gas supply portfolio, and also has a natural hedge against gas price volatility because of the relationship between electricity and gas prices (BC Hydro Reply, pp. 6, 7).

CEC argues that by failing to provide a level playing field, BC Hydro has transferred value from its customers to a particular proponent resulting in resource bias, and that BC Hydro has missed an opportunity to obtain critical market information to allow tradeoffs to be made (CEC Argument, pp. 11, 12). Mr. McKechnie also argues that the natural gas tolling option biased the CFT (McKechnie Argument, p. 2).

The benefits that the tolling options bring to BC Hydro and its ratepayers were not quantified and depend largely on BC Hydro's confidence that it can more cost-effectively manage gas supply and gas and transportation costs than project proponents. The fact that gas-fired project proponents chose the tolling option indicates that they felt it would be beneficial to them. Logic suggests that proponents with other fuels may also have found that BC Hydro taking the risk on fuel cost and transportation may have permitted them to bid a wider range of projects and to tender bids that included smaller risk premiums.

The Commission Panel accepts, with respect to short-term price risk, BC Hydro's arguments that it can manage gas price risk more easily than other fuel price risk because a more transparent and liquid short-term forward market exists for natural gas than for other fuels and the proponents of most non-gas-fired projects would likely control their fuel supply (e.g. coal and possibly biomass). The Commission Panel is not persuaded that BC Hydro is better able to manage longer-term risks related to gas prices, but accepts that BC Hydro is likely in a better position than proponents to manage long-term gas physical supply given its size, marketing infrastructure, existing portfolio of generation resources and portfolio of electricity purchase and sale requirements. Therefore, the Commission Panel is persuaded that bids from proponents that include management of gas price risk are likely to over-estimate the risk premium for BC Hydro.

Although BC Hydro is likely in a better position to manage gas supply price risk than project proponents, the cost of doing so is not zero. In comparing a gas-fired tolling bid relative to some other project, it is not reasonable to attach no cost to managing gas price risk. Ideally, the premium for managing gas price risk would be developed by BC Hydro and provided to proponents before they bid. BC Hydro seems to be well aware of the difficulties with attempting to establish such a risk premium by analytical methods (Exhibit B-9, BCUC IR 1.17.1), but did not attempt to structure the CFT so that competitive bids would establish the premium. BC Hydro stated that the $18 million development fee in the VIGP asset transfer price considered that the buyer of VIGP assets would not be required to assume gas supply risk (Exhibit B-1, Appendix C). Alternatively, it appears that BC Hydro may have assumed that the price forecast methodology was effectively dealing with the gas price risk premium by using a conservative heat rate assumption (i.e., a 50/50 weighting of the EIA-Partial and EIA-Full Forecasts) as a way of leveling the playing field with non-gas-fired projects. While this may be the case, the approach is not transparent and the Commission Panel finds it difficult to assess the reasonableness of any such "implicit" premium. Moreover, reflecting the premium in the electricity price forecast could affect the evaluation of contracts with fixed energy prices (because it affects their energy margins), and also does not reflect the risk of structural increases in gas prices over the 25-year term of the EPA relative to fixed fuel costs for projects that use other fuels and did not have a tolling option.

In summary, the Commission Panel accepts BC Hydro's arguments that it is in a better position to manage fuel price risks for gas-fired plants than project proponents. Although the cost to BC Hydro of managing gas supply price risk is not zero, the Commission Panel accepts that in the context of the Vancouver Island CFT, this risk is adequately captured in the use of a conservative heat rate in comparing tenders. However, the Commission Panel encourages BC Hydro to explore more transparent ways of reflecting differences in fuel risk within future CFTs. The Commission Panel also accepts BC Hydro's arguments that it has no unique capabilities in managing price risk for other fuels such as biomass, and in the absence of transparent and liquid markets for these fuels it is unlikely to be able to manage these risks better than project proponents. The Commission Panel notes that all things being equal BC Hydro's willingness to assume gas supply price risk could favour gas-fired projects over other fuel sources, but is not persuaded that this constitutes an inappropriate or unfair resource bias, since it reflects a real difference in the cost of alternative sources of generation to BC Hydro and its ratepayers, provided that the gas supply price risk is adequately reflected in the price forecast methodology or other adjustments to gas-fired bids.

4.3.2 Mandatory CFT Criteria

The amended CFT called for Pre-Qualification Submissions by March 29, 2004. Prior to the receipt of Pre-Qualification Submissions, BC Hydro's technical and financial evaluation committees established detailed evaluation guidelines for all mandatory criteria. The Independent Reviewer found that BC Hydro was consistent, objective and fair in evaluating the 14 Pre-Qualification Submissions (Exhibit B-1, Appendix K3, p. 5). The Pre-Qualification evaluation resulted in 11 valid submissions and 3 failed submissions. Many intervenors commented on the constraining or biasing effects of the CFT's mandatory criteria. The comments point to specific criteria and the general effect when all the criteria are taken as a whole. Several of these specific criteria are examined below. Some intervenors also argue the aspect of the rigidity of interpreting material versus non-material conformance to the mandatory criteria, and the resulting rejection for non-conformance.

Rejection for Non-conformance with Mandatory Criteria

Green Island observes that BC Hydro has not delineated whether rejected Tenders were disqualified for material or non-material non-conformities (Green Island Argument, pp. 12, 13). There had been some attempt by BC Hydro to use the Decision Making Process in Appendix A of Exhibit B-69 to clear up three non-conformities, but the extent of the clarification sought and for which bidder is not given (T8: 1855-1856; Exhibit B-1, Appendix K4, p. 8).

The JIESC submits that evidence that the CFT was unduly constrained is provided by the fact that six bids were received from a pool of 23 potential bidders (JIESC Argument, pp. 12, 13). BC Hydro and the Independent Reviewer characterize this as a "robust level of interest", noting that this is more than is often received in comparable cases, and more than their minimum requirement of three bids to be considered competitive (BC Hydro Reply, p. 17; T8: 1797).

The need for certainty and expediency of the CFT process was well identified. The Commission, in the VIGP Decision, determined there was a need to move expeditiously to reinforce electricity supply to Vancouver Island prior to the winter of 2007/08 (VIGP Decision, p. 78). Further, the Commission letter of January 23, 2004 stated that it "does not consider that the further delay which would result from a more protracted process at this stage is justified or is necessary in the circumstances" (Exhibit B-1, Appendix F, p. 2). The Commission letter also considered, in addition to specific issues that were addressed individually, a number of other mandatory requirements that had attracted comments. The Commission was concerned that "if such requirements are more stringent or less flexible than the minimums that are needed, thereby increasing costs for ratepayers by disqualifying otherwise worthwhile projects or by increasing bid prices". The objectives of the CFT process were, among others, to be fair and accommodate "the widest range of supply technologies and options", but also to be timely to satisfy the schedule (Exhibit B-1, Appendix A, Schedule A, Section 9). Therefore, the qualification of bids required firm and clear pass/fail compliance tests in order not to delay the process.

There are a number of instances where prospective bidders were alerted to the need for compliance with the CFT terms, and that non-conforming tenders would be rejected. The CFT itself contained specific terms to enable BC Hydro to eliminate non-compliant bids. Section 10.7 required unconditional tender security of $10,000/MW and went as far as to bold a passage alerting prospective bidders that the consequence of non-conformance would be rejection of the tender (Exhibit B-1, Appendix B, p. 14). Section 18.17 gave BC Hydro sole and unfettered discretion to determine material and non-material non-conformities, as well as the right to reject tenders for both material and non-material non-conformities. A slide was presented during the Bidders' Tender Workshop of July 7, 2004 that again identified to bidders that non-conformance for a variety of reasons would result in rejection of the tender (Exhibit B-60). **The Commission Panel concludes that bidders had adequate notice that non-conforming bids were likely to be rejected.**

<u>Minimum Term Requirement</u>

The minimum term for bids in the CFT was changed from 10 years to 25 years in Addendum 10 to the CFT (Exhibit B-1, Appendix G). BC Hydro chose this fixed term primarily to simplify the QEM analysis. This change was made after the pre-qualification stage and BC Hydro testified that it received no objections from bidders at the time of the change (T6: 1215-1217).

The 25-year term of the CFT attracted comments from many intervenors. Green Island argues that the evaluation of differing terms could have been readily accomplished within the QEM (Green Island Argument, p. 12). The JIESC (JIESC Argument, p. 14) and CEC (CEC Argument, p. 18) recognize that the common term makes comparison of projects easier, but argue that this also reduced the number of projects that might be bid successfully. The JIESC argues further that this length of term contributed to resource bias against certain projects that were tied to cogeneration hosts or other types of facilities.

BCOAPO (BCOAPO Argument, p. 12) and Hill (Hill Argument, pp. 4, 5) observe that projects of this nature require long-term contracts to attract financing, which is also the evidence of BC Hydro (T7: 1582).

The Independent Reviewer concurred that the selection of a fixed 25-year term would simplify the QEM analysis (Exhibit B-35, Letter of March 11, 2004, p. 2). In the opinion of the Independent Reviewer, the term was consistent with terms of 20 to 30 years that are typical within the industry for greenfield capacity-driven projects (T8: 1851-1852). Opening up the QEM to consider different terms for various projects would allow for potential disagreement as to the "backfilling" assumptions (T8: 1824). BC Hydro also submits that the CFT was intended to be a long-term capacity replacement to reflect the characteristics of the asset being replaced (T6: 1098-1099).

The JIESC characterizes the EPA as a 35-year contract (JIESC Argument, p. 14). This argument is considerably tempered by the provisions contained within the final form EPA Article 2.3 and Appendix 16 that allow the seller to submit new pricing terms after the initial 25-year term (Exhibit B-1, Appendix N). This effectively limits the seller's initial project risk to the 25-year term. These same EPA provisions limit the breadth of the issues that can be considered at the time of renewal. **The Commission Panel accepts that some sellers may have interpreted the non-pricing provisions of future renewal term negotiations to have unacceptable risk, but concludes that the renewal term negotiation provisions provide acceptable recovery mechanisms.**

With respect to the minimum initial 25-year term, the Commission Panel agrees that the longer term may have been required for many project proponents to secure financing but it could also have excluded some other projects. However, the Commission Panel also finds that the 25-year term was not demonstrated to be unreasonable in this particular instance given the system capacity considerations associated with this CFT, and the typical industry experience for greenfield capacity

calls. The Commission Panel is also not persuaded that altering the minimum term in the Vancouver Island CFT would have led to a different outcome, particularly given the change was made after the pre-qualification stage. Except for a conditional bid from Calpine, which it appears would have been rejected in any event for not meeting minimum tender security requirements (BC Hydro Argument, p. 36), no evidence was filed during the proceeding identifying specific capacity projects that were excluded and that could have been in-service during the timeframe contemplated by the CFT.

The Commission Panel disagrees with BC Hydro that a single term is required to compare bids. While a minimum term is justified in the context of capacity solutions with long lead times, the Panel is not convinced that the term for all tenders must be equal to allow fair comparison of bids that meet the minimum term requirement. Levelized capacity or energy costs are often used precisely because they allow comparison of projects with different terms. All things being equal, a project with a longer term may be preferred to one with a shorter term. However, it is not evident that beyond some minimum term requirement, BC Hydro should necessarily be willing to pay a higher levelized cost for projects with much longer terms, particularly in light of renewal opportunities, and the high uncertainty associated with costs and benefits far into the future.

Availability Criteria of 97 Percent

Green Island (Argument, pp. 11, 12), the JIESC (Argument, p. 16), and CEC (Argument, pp. 18, 19) argue that the 97 percent availability criterion contributed to a resource bias within the CFT. They argue that this bias could arise for several reasons: non-gas-fired technologies might have chosen not to bid as a result of their inability to achieve the required availability, and those that did bid in might have de-rated their maximum capacity in order to increase their availability.

BC Hydro explained that it established 97 percent availability during the period October to March inclusive as a requirement for the specific product that it was seeking and noted that everyone had an opportunity to bid to that product specification (Exhibit B-1, Appendix B, Section 9.8 and Appendix I; T8: 1828). BC Hydro established that several technologies were capable of meeting this criterion (BC Hydro Argument, p. 25). Projects that did not meet this criterion were deemed incompatible with the fundamental nature of the CFT as a high-reliability capacity replacement (T8: 1698).

The Commission Panel finds that the 97 percent availability criterion in all likelihood benefited certain projects, however, in this unique situation, considers that the criterion was appropriate because it reflected the critical nature of the asset in meeting the long-term capacity requirements of the Vancouver Island system as identified at the outset of the CFT process.

Overall, the Commission Panel considers that the CFT process was designed with suitable terms and sufficient flexibility to attract a reasonable number of competitive bids and to meet the objectives of the CFT.

4.3.3 Privative Clause

A privative clause was introduced by BC Hydro in CFT Addendum 10, issued March 5, 2004 (Exhibit B-1, Appendix G, p. 4). The purpose of this clause was to reflect direction received in the Commission letter of January 23, 2004. As stated in that letter, BC Hydro was encouraged to seek approval for a solution of at least 150 MW, comprised of cost-effective projects. If such a solution was not available, BC Hydro was to seek out a portfolio of cost-effective projects aggregating at least 115 MW before considering resource additions other than on-Island generation. Specifically, Article 17.3 states in part:

> "If Tenders received pursuant to the CFT, which meet the Mandatory Criteria and are assessed not to have a high development risk (i) aggregate less than 150 MW of Bid Capacity, or (ii) aggregate 150 MW or more of Bid Capacity, but BC Hydro determines, in its sole and unfettered discretion, that acceptance of any such portfolio is not the most cost effective solution having regard to BC Hydro's ratepayers, then BC Hydro reserves the right to accept one or more Tenders comprising in the aggregate less than 150 MW of Bid Capacity. This right is exercisable in BC Hydro's sole discretion with a view to procuring the most cost-effective Dependable Capacity meeting its requirements on Vancouver Island."
>
> (Exhibit B-1, Appendix G, p. 4)

Green Island (Argument, pp. 8, 11) argues that Article 17.3 of the CFT Addendum Number 10 and Article 18.17 created certain obligations for BC Hydro within the CFT process (T16: 3301-3307). BC Hydro replies that the interpretation of contractual rights and obligations is best done in a forum dedicated to interpretation of contract law (BC Hydro Reply, pp. 28, 29; T16: 3296-3297).

BC Hydro refined its interpretation of when the privative clause would be invoked, as documented in minutes of a Project Management meeting held on August 12, 2004 (Exhibit B-65, Section 8). In addition to the ability to invoke the clause in the event of a non-competitive process or outcome, collusion among the bidders would also allow the clause to be invoked.

In Argument, BC Hydro pointed out that Section 17.3 of the CFT was introduced after the process was initiated and that it grants BC Hydro the right but not the obligation to award one or more contracts totalling less than 150 MW where senior management concludes, in their discretion, that the so-called Tier 1 outcome is not cost-effective (BC Hydro Argument, p. 35).

The Commission Panel agrees with BC Hydro that the privative clause gives it the right but not the obligation to award one or more contracts totalling less than 150 MW where senior management concludes that the so-called Tier 1 outcome is not cost-effective. As discussed further below, BC Hydro's decision about whether to exercise this right was informed by 1) evidence of a competitive tender process; 2) a comparison of the winning Tier 1 outcome with the VIGP benchmark; and 3) a comparison of the winning Tier 1 outcome with the so-called Tier 2 and No Award alternatives.

4.3.4 CFT Portfolio Criteria

The VIGP Decision confirmed that the scope of the CFT process should consider an outcome with a capacity of at least 150 MW, as long as each project is cost effective. The Commission letter of January 23, 2004 quoted this passage from the VIGP Decision and reiterated that cost-effective portfolios with dependable capacities as low as 115 MW should be accepted before considering resource additions other than on-Island generation (Exhibit B-1, Appendix F, p. 3).

Green Island argues that when it became clear to BC Hydro that the capacity of a particular bid did not conform to the prescribed portfolio size (Exhibit B-1, p. 13), BC Hydro should have sought the Commission's guidance in terms of how best to deal with a such a bid (Green Island Argument, p. 12).

The selection of the 300 MW upper value for the CFT range was chosen by BC Hydro because it represented what it believed to be the maximum output of a gas-fired plant with duct-firing (T6: 1187). The selection of this upper bound attracted comments from Gold River and Green Island that it is too low because it leaves some projects stranded (T1: 152; Green Island Argument, pp.14, 15). The JIESC observes that as the upper limit of the range increases, so does the potential risk because of the contract size (T1: 245). BC Hydro argues that the 300 MW limit satisfies the immediate urgent need (T1: 288-289). The Commission Panel noted the 300 MW upper value in its January 23, 2004 letter and determined on November 30, 2004 that portfolios exceeding the 300 MW upper limit of the CFT capacity range were outside the scope of this hearing, and that capacity additions over this amount need to be considered in an overall context of resource planning (T2: 312).

BC Hydro believed that the analysis methodology favoured tenders nearer the 150 MW threshold of the CFT relative to tenders nearer the 300 MW threshold (Exhibit B-1, p. 7). Ms. Hemmingsen's testimony supports this claim (T7: 1527-1528). No evidence has been advanced that the analysis methodology was inconsistent with this claim (T6: 1110; T8: 1731-1732).

The Commission Panel finds that the conditions that led to the minimum desirable CFT capacity of 150 MW identified in the VIGP Decision are still present, and this minimum capacity continues to be valid. Indeed, the Commission Panel notes that the load forecast evidence in this proceeding suggests the actual need for capacity will exceed the amount used by the Commission in recommending BC Hydro seek a minimum aggregate capacity addition of at least 150 MW (VIGP Decision, p. 83). The Commission Panel confirms that capacity additions in excess of 300 MW are to be considered in an overall context of system resource planning, and accepts the upper capacity limit of the CFT. The Commission Panel finds credible the testimony of BC Hydro (Ms. Hemmingsen) that it considered that the CFT would favour bids at the lower end of the desired range, and that BC Hydro was ultimately surprised by the results. The Commission Panel also notes that the cost-effectiveness of the preferred Tier 1 outcome was further tested through a comparison with the VIGP benchmark and through a subsequent cost-effectiveness evaluation that compared the preferred Tier 1 outcome with the Tier 2 and No Award alternatives. This cost-effectiveness evaluation considered projects totalling less than 150 MW, but also incorporated additional and relevant qualitative considerations not reflected in the QEM used to compare possible Tier 1 outcomes.

4.4 The CFT Scope and Process

The Commission Panel identified that all CFT criteria that are relevant to the selection of Tier 1, Tier 2, and the No Award alternatives were within the scope of the hearing. However, the Panel also noted "that in the absence of evidence from developers, it may not be persuaded that the CFT is not satisfactory evidence that Duke Point is the most cost-effective resource for Vancouver Island at this time" (T2: 312). Beyond the flexibility afforded by this identification of scope, the Commission Panel determined that no other resource options needed to be considered. With regard to whether or not BC Hydro conducted the CFT in accordance with its terms (but not as to whether these terms were appropriate), the Commission Panel determined this issue to be outside the scope of this hearing and that the Independent Reviewer need not be called in this proceeding (T2: 314).

In allowing a full discussion into the criteria that were relevant to the selection of alternatives, the Commission Panel received a significant body of evidence and heard testimony that went beyond the intended scope of this hearing. The Commission, in its letter of January 23, 2004, gave direction that confined the scope of the CFT in some respects to assist in arriving at a competitive and cost-effective outcome to the CFT in a timely manner. Similarly, in defining the scope of this hearing, the Commission Panel has sought to preserve the consistency of the direction provided in the VIGP Decision and the January 23, 2004 letter, especially in instances where the underlying principles that established those original directions had not fundamentally changed since the VIGP Decision. The Commission Panel has adhered to this objective in order to consider the outcome of the CFT process in the context that had been previously defined.

Aside from specific evidence supplied by Green Island, no other developers stepped forward to submit details of their projects to dispute the criteria used and the outcome of the CFT process (Confidential Exhibit C9-14; Confidential Exhibit C9-19). **Although information was put on the record regarding the characteristics of projects of other bidders who participated in the CFT process, without those bidders themselves presenting evidence or comment, the Commission Panel considers that it would not be appropriate to rely on or give much weight to such information.**

4.5 Value of the CFT to Demonstrate Cost Effectiveness

The CFT was designed to find through a competitive bidding process the most cost-effective long-term, on-Island generation project(s) meeting the Mandatory Criteria and with total dependable capacity of between 150 MW and 300 MW. The QEM employed in the CFT selected the project or projects meeting these criteria with the lowest Net Portfolio Cost NPV (i.e., the Tier 1 outcome) (Exhibit B-1, p. 13). A competitive CFT was intended to be the primary demonstration of cost-effectiveness of the Tier 1 outcome. BC Hydro also performed two additional tests to confirm the cost-effectiveness of the Tier 1 outcome in this CFT. First, BC Hydro compared the winning Tier 1 outcome with the QEM results for the VIGP benchmark (Exhibit B-1, pp. 13, 21, 22; Appendix J, p. 1; Appendix L). The VIGP benchmark considered only incremental costs for completing the project, as outlined in the VIGP Decision. Second, BC Hydro compared the Tier 1 outcome with the Tier 2 and No Award alternatives. The Tier 2 alternative involved a package of on-Island generation projects from the CFT aggregating to less than the minimum 150 MW, supplemented with other short-term alternatives not eligible for the CFT such as demand management and temporary generators. The No Award alternative excluded any long-term on-Island generation, relying instead entirely on temporary generators and demand management prior to the in-service date of the next 230 kV cable to the Island. Cost-effectiveness was tested under several scenarios of future load requirement, mainland generation cost, and 230 kV project timing (Exhibit B-1, Appendix J). In addition to costs, this final cost-effectiveness test also examined important qualitative considerations such as reliability and certainty of alternatives to the Tier 1 outcome.

The Commission Panel acknowledges some deficiencies within the CFT process conducted by BC Hydro. However, the Commission Panel finds no compelling evidence **that the CFT was fatally flawed. The Commission Panel finds that the process was adequate for determining the most cost-effective on-Island generation option(s) meeting the parameters originally established in the VIGP Decision. The Commission Panel is also reassured by the additional checks provided for the CFT outcome – namely the comparison of the winning Tier 1 bid with the VIGP benchmark and the Tier 2 and No Award alternatives.**

The Commission Panel notes that the evaluation process and cost-effectiveness thresholds considered in this proceeding are unique to the Vancouver Island CFT. The Commission Panel expects that future resource calls will be informed by upcoming regulatory processes associated with the filing and consideration of the Resource Expenditure and Acquisition Plan (“REAP”), the Resource Option Report (“ROR”) and the Integrated Electricity Plan (“IEP”). **The Commission Panel expects those processes to define thresholds and processes for determining the cost-effectiveness of future resource additions.**

5.0 QUANTITATIVE EVALUATION METHODOLOGY MODEL

The Commission, in the VIGP Decision, expressed concern about the lack of transparency in the various models used by BC Hydro to evaluate resource acquisition decisions and indicated that it "…expects BC Hydro to use assessment models which can be made public so that the various components and assumptions can be assessed and tested by intervenors" (VIGP Decision, p. 71). Furthermore, the Commission also concluded that "…given that the logical next resource addition is on-Island generation, it should be possible to develop a simplified NPV model specifically for the CFT. The NPV model should be available to bidders in advance and the Commission Panel believes that it could be limited to on-Island generation costs, without the need to consider future impacts to electricity transmission or generation on the Mainland" (VIGP Decision, p. 81). These concerns were further elaborated in the Commission's January 23, 2004 letter to BC Hydro responding to BC Hydro's request for Commission approval of the terms of the CFT.

In response to these concerns, BC Hydro developed the QEM to identify the most cost-effective new generation solution for the Vancouver Island capacity shortfall. A preliminary version of the QEM was provided to all CFT bidders in mid-November 2003, with a final version of the QEM issued to bidders on August 6, 2004. BC Hydro also held a workshop with registered bidders on January 6, 2004 to demonstrate the QEM and answer bidder questions about the model.

On December 2, 2004, BC Hydro filed in confidence with the Commission Panel and staff a copy of the final QEM and accompanying manual, together with the input data for all tenders and portfolios meeting the Mandatory Criteria and passing the Development Risk Assessment. A total of four tenders (consisting of six mutually exclusive projects) and five different portfolios were evaluated within the QEM. The VIGP benchmark portfolio was also evaluated using the QEM.

As stated by BC Hydro:

> "The QEM was built on the conclusions of the Commission in the VIGP decision as elaborated in the exchanges that led to the 23 January 2004 letter. It was also influenced by the feedback from the prospective bidders during the Q and A sessions, by the exchanges with the Commission, by the advice of the Independent Reviewer, and by the independent external experts retained in connection with the CFT process. Its purpose was to extract the lowest cost bid that could be obtained from the market and that met the criteria established by the Commission using an evaluation methodology with characteristics recommended by the Commission."
>
> (Exhibit B-9, BCUC IR 1.15.1)

The QEM is a financial evaluation model developed in MS-Excel. The QEM evaluates Tenders and Portfolios over the required 25-year term from the Commercial Operation Date, without regard to renewal rights. It consists of two components: 1) a tender evaluation; and 2) a portfolio evaluation. These are described in much detail in Appendix H of the CFT Application (Exhibit B-1). A brief summary is provided here.

The tender evaluation calculates the NPV of all direct costs and benefits of the capacity and associated energy of each Tender (the "Net Tender Cost"). The Net Tender Cost is calculated as the NPV of tender fixed costs plus the NPV of plant start-up expenses less the NPV of any Energy Margin produced by the plant. Fixed costs include the capital charges and operation and maintenance charges provided by each bidder. The tender evaluation also includes a simplified generation dispatch model for estimating the expected monthly heavy load hours ("HLH") and light load hours ("LLH") energy production from dispatchable plants based on dispatch costs and electricity prices. The Energy Margin is the difference between the value of expected dispatch and the variable costs of electricity production. The Energy Margin is credited against the fixed costs of the EPA.

The value of electricity used to calculate dispatch and estimate the Energy Margin is derived from two different electricity price forecasts developed by BC Hydro and referred to as EIA-Full and EIA-Partial. In the case of gas-fired tolling plants, the variable costs of production include the gas commodity costs, which are estimated using a forecast from the Energy Information Administration ("EIA"), together with any variable gas transportation costs provided by Terasen Gas (Vancouver Island) Inc. ("TGVI") and any variable Energy Charges provided by each bidder. For all other types of plants (e.g. non-tolling gas plants and plants based on other fuel sources), the Energy Margin is based on the value of electricity and the Energy Charges provided by bidders. The price forecasts and other key input assumptions to the QEM are discussed elsewhere in this Decision.

The portfolio evaluation calculates the costs and benefits of the capacity and associated energy of each Portfolio (the "Net Portfolio Cost"). A portfolio is defined as any individual project or combination of projects with an aggregate capacity between 150 to 300 MW. A total of five possible portfolios were identified from the accepted tenders. The Net Portfolio Cost reflects the Net Tender Cost of each bid in the portfolio, together with adjustments for VIGP asset value, firm gas transportation costs, and network upgrade costs. No credit was provided for transmission deferral in the QEM. The Net Portfolio Cost of each portfolio was calculated using the average of the Net Tender Costs calculated using the two electricity price forecasts in the QEM.

The QEM was used to select a winning tender or portfolio meeting the mandatory criteria of the CFT (the Tier 1 outcome). The QEM defines the preferred CFT option as the tendered project or projects comprising the portfolio with the lowest Net Portfolio Cost on an NPV basis. This is referred to as the "Tier 1" outcome (BC Hydro CFT Report, p. 13).

The QEM is distinct from the broader high-level cost-effectiveness analysis subsequently conducted at the request of BC Hydro senior management and in regard to Section 17 of the CFT, which permitted BC Hydro to determine if the Tier 1 CFT results were cost-effective relative to the Tier 2 option and no CFT award options. The Tier 2 option, as defined by BC Hydro, involves exercising the privative right and awarding the EPA to two smaller projects totalling 122 MW less than the minimum 150 MW defined in the CFT process (BC Hydro CFT Report, p. 14). The No Award option involves exercising the privative clause and canceling the entire CFT. Both the Tier 2 and No Award options would also require reliance on demand management and temporary generators for one or more years to address capacity shortfalls until the first 230 kV cable is in service.

Most of the criticism of the QEM during the proceeding focused on specific assumptions within the model and their potential impact on bid comparisons. These criticisms are dealt with in the sections that follow.

The JIESC offered a general criticism of the QEM as follows:

> "There is no attribution of comparative risk to any projects. The end result of this is that a low risk project is treated in the same manner as a high risk project, to the detriment of the low risk project and BC Hydro's ratepayers. A dollar of contracted cost and expense, for example a fixed monthly fee, or a fixed commodity charge are treated the same as a speculative dollar of energy margin. The effect of this is to give a bid like DPP's, that has a lot of speculative energy value associated with it, a substantial advantage in comparison to a peaking plant with largely fixed costs and little energy."
>
> (JIESC Argument, p. 18)

Commission Panel Determination

The Commission Panel acknowledges BC Hydro's efforts to simplify the evaluation model for the purposes of the CFT and to provide bidders with a copy of the model to assist in their bid preparation. The Commission Panel accepts the general framework of the QEM for the purposes of this CFT process. With respect to the JIESC criticism regarding the general treatment of risk in the model, the Commission

Panel notes that BC Hydro has in part addressed the relative risks of different projects through conservative input assumptions – for example, conservative heat rate assumptions as discussed further below. The Commission Panel does not find any evidence in this particular instance that the treatment of risk in the QEM resulted in an inappropriate bias among the available Tier 1 projects that were ultimately evaluated within the QEM, particularly given that all of the possible Tier 1 outcomes involved gas-fired projects. The Commission Panel also notes that further risk analysis was conducted as part of the broader cost-effectiveness evaluation comparing the winning Tier 1 outcome with the Tier 2 and No Award outcomes. The Commission Panel is not persuaded that it should reject the outcome of this particular CFT based on the treatment of risk in the QEM. However, the Commission Panel does encourage BC Hydro to consider carefully alternative ways to represent the relative risks of competing tenders in future acquisitions. It expects the appropriate treatment of risk in any future calls will be dealt with in future ROR, IEP and REAP processes that will proceed those calls.

6.0 GREENHOUSE GAS RISK

The existing Environmental Assessment Certificate ("EAC") for VIEC will be transferred to DPP as part of the share and asset transaction (Exhibit B-1, Appendix O, p. 7). Under the terms of Schedule B of the EAC, BC Hydro has committed to offset 50 percent of the increase in emissions from VIGP to year 2010 through new energy efficiency and renewable energy efforts. In Response to GSXCCC et al. Supplemental IR 2.7.2, BC Hydro indicated that it had already fulfilled its commitment in this regard before the notion of a CFT was contemplated and that the NPV of the incremental cost associated with this commitment in relation to DPP is zero (Exhibit B-101, p. 7).

Clause 8.10(c) of the EPA assigns responsibility to the Seller for any future regulatory and legal requirements with respect to all emissions from the Seller's plant, including GHG emissions. As a result, GHG emissions were not included in the QEM, except in the evaluation of the VIGP benchmark, under which BC Hydro would have been entirely liable for GHG emissions, as set out in the VIGP Decision (VIGP Decision, pp. 51, 52).

During the hearing and in Argument, several intervenors questioned whether the GHG risk had been adequately dealt with in the evaluation. Testifying on behalf of GSXCCC et al., Dr. Jaccard stated that it is far more probable that governments will employ taxes or other obligations at the natural gas production point than at the point of emissions. Under such an approach, any cost burden associated with GHG emissions would likely be borne by BC Hydro (T14: 2967-2969).

In Argument, GSXCCC et al. argued that "…the public interest lies in discouraging gas-fired electrical generation regardless of any allocation of GHG penalties between BC Hydro and DPP" and also that "…the EPA leaves BC Hydro at risk of taking over DPPs GHG emissions liabilities in the event of default by DPP" (GSXCCC et al. Argument, p. 2). BCOAPO agreed that "any regulatory costs or other burdens that are not directly tied to emissions from the plant remain on the shoulders of BC Hydro and its ratepayers" (BCOAPO Argument, p. 14).

BC Hydro maintained that DPP is fully responsible for GHG emissions from the plant. Citing evidence from Dr. Bramley, expert witness for GSXCCC in the VIGP proceeding (VIGP Exhibit 19B per Exhibit C20-30 of this proceeding), BC Hydro also argued that most GHG policy options being discussed for industrial emitters in Canada and elsewhere are based on regulating or taxing emissions, not fuels (BC Hydro Argument, p. 30). With respect to the possibility of default, BC Hydro pointed out that in the event of default:

> "… it [BC Hydro] is entitled to $36 million as a deduction from the payment for the power to deal with any noncompliance by DPP. Also, the EPA and Lender Consent Agreement are designed to provide BC Hydro with the greatest possible protection and flexibility that contracts can offer against the risk of Seller insolvency for whatever reason. In particular, BC Hydro has letter of credit security, a subordinated charge on all project assets, step-in rights and rights of terminations, including termination of Seller insolvency."
>
> (BC Hydro Argument, p. 29)

DPP characterized Dr. Jaccard's evidence as "speculation" on the potential future liabilities associated with GHGs and indicated that DPP had spent a great deal of time analyzing the GHG issue and had consulted two outside experts, as well as in-house capability, to assess this risk before agreeing to assume responsibility for it (T10: 2242-2243).

Commission Panel Determination

The Commission Panel accepts that the EPA transfers to DPP the risk of any future regulatory or legal requirement with respect to GHG emissions at the plant. The Commission Panel acknowledges the possibility that future GHG regulation could be implemented in such a way that the burden is placed upstream from the plant and could therefore be borne by BC Hydro. However, the Commission Panel considers this scenario as less likely. Furthermore, in accepting this EPA, the Commission is not providing any direction regarding future recovery of GHG costs that may be borne by BC Hydro. Indeed, given the evidence provided by BC Hydro and DPP in this proceeding in reviewing the allocation of any future GHG costs associated with the DPP plant and borne by BC Hydro, the Commission may reasonably conclude that such costs are not prudent or justified, and should therefore be allocated to the shareholder rather than the ratepayer. **With respect to any liability arising as a result of possible default by DPP under a circumstance of high GHG mitigation costs, the Commission Panel accepts that the $35-36 million in annual capacity payments available to BC Hydro under the terms of the EPA, and the fact that actual dispatch could be adjusted to reflect the additional costs arising from GHG liability, should be sufficient to protect ratepayers.**

7.0 GAS PRICE RISK AND CAPACITY FACTOR

7.1 Gas Price Forecasts in the QEM model

Price forecasts, both gas and electricity, are important to the evaluation of the EPA because the forecast risk is borne by ratepayers. BC Hydro developed a new price forecasting process (Exhibit B-97, O'Riley Rebuttal Evidence, p. 3) that is used in the QEM model for Tender and Portfolio evaluations. This section will first consider the price forecasts used in the QEM model and then the submissions of intervenors related to price forecasts followed by BC Hydro's response to the analysis provided by intervenors.

In the QEM model, BC Hydro used the January 2004 EIA Reference Case gas price forecast and then converted the EIA gas price forecast to two electricity price forecasts. The first power price forecast is referred to as the 100 percent (full) Capital Cost Recovery Forecast ("EIA-Full") and the second is referred to as the 25 percent (partial) Capital Cost Recovery Forecast ("EIA-Partial"). A description of the EIA-Full is found in Exhibit B-1, Tab H, Section 3.4.2 and a description of the EIA-Partial is found in Exhibit B-1, Tab H, Section 3.4.3. In the QEM, an NPV is calculated for each power price forecast and then an average NPV is calculated that is determinative of the winning Tier 1 portfolio (Exhibit B-1, Tab H, Section 4.5). This approach was used because the expected dispatch of plants is very different under each forecast, and is not necessarily the same dispatch as would be observed when using an average of the two price forecasts.

The EIA gas price forecast is converted to the two power price forecasts using the Henwood Energy Services simulation model for the period 2008-2012. The Henwood model forecasts hourly electricity prices based on the price of the marginal resource when supply and demand are in equilibrium for that hour. Beyond 2012, BC Hydro uses a "short-hand" methodology (T15: 3114) that assumes the marginal resource is an F-series gas-fired generation plant and the hourly power price is determined using the hourly profile from the Henwood model (T15: 3146).

The approach to price forecasting used in the QEM evolved from using five electricity price scenarios to using three gas price forecasts and two methods of modeling electricity prices to using a single gas price forecast and two methods of modeling electricity price forecasts (Exhibit B-9, BCUC IR 1.13.1; Exhibit B-97, O'Riley Rebuttal Evidence; T14: 2996).

The average of the three gas price forecasts was very close to the EIA gas price forecast and the average of the two electricity price forecasts was very close to the six electricity price forecasts on a 25-year levelized basis (Exhibit B-9, BCUC IR 1.13.1). The number of price forecasts used in the QEM model was reduced to simplify the model. The EIA gas price forecast and the corresponding derived electricity price forecasts were applied to the energy output of each CFT portfolio. The energy margin that resulted offset the fixed costs of the portfolio in the QEM model to determine the net portfolio cost.

7.2 Market Heat Rates and Plant Capacity Factors

7.2.1 Market Heat Rate Concept

The price risk to a gas-fired generator arises from the ratio of gas to electricity market prices, which is referred to as the market heat rate ("MHR") and is typically expressed as $/GJ divided by $/MW.h (Exhibit B-9, BCUC IR 1.13.3). The DPP plant will operate at a conversion efficiency of approximately 7.3 GJ of natural gas for each MW.h (T6: 1242). When the MHR is 7.3 or lower, the DPP plant will not be dispatched unless required to meet load requirements on Vancouver Island. When the MHR is greater than 7.3, then dispatch will result in a contribution to dispatch variable and fixed costs. A detailed description of dispatch modeling can be found in Exhibit B-1, Tab H, Section 4.

The risk of persistently low MHRs was assessed by BC Hydro through the use of the EIA-Partial price forecast. In this electricity price forecast, the EIA gas price is converted to an electricity price by assuming that a combined-cycle gas turbine plant would recover only 25 percent of its original capital investment. The case was analogous to the "Alternative Heat Rate" scenario used by BC Hydro in an earlier approach to forecasting. To be conservative, BC Hydro increased the weighting of this case from 20 percent to 50 percent in the final QEM (Exhibit B-9, BCUC IR 1.13.3). Although the weighting was increased, the new "Alternative Heat Rate" scenario was dependent, unlike Option 4 (Exhibit B-97, O'Riley Rebuttal Evidence, February 9, 2004 PowerPoint Presentation, Slide 10; JIESC Argument, pp. 25, 26), on the conversion from gas to electricity to calculate power prices (BC Hydro Reply, p. 11).

7.2.2 The JIESC Expert Evidence

Expert evidence provided on behalf of the JIESC concluded that the DPP plant would generate a positive energy margin in less than 30 percent of the hours of the year, and at this capacity factor the levelized cost per MW.h of the plant is over $150 in 2007 (Exhibit C19-11, Fulton, p. 2). Mr. Sheldon Fulton identified three risks of operating the DPP plant: 1) Energy Margin Risk; 2) Energy Price Risk; and 3) Utilization

Risk. Mr. Fulton's analysis uses three different sources of data: 1) EIA gas and power price forecasts; 2) historic reported actual natural gas and electricity prices from January 2002 through December 2004; and 3) forward price curves through the year 2010.

In the examination of the Energy Margin Risk, Mr. Fulton calculates MHRs using the EIA power price forecast and states that this results in an MHR of 9.2 for the 2007 to 2025 time period, which is 1.1 lower than the MHR of 10.3 used in the QEM model (Exhibit C19-11, Fulton, p. 5). Mr. Fulton then states that:

> "It is difficult to understand why the analysis model [QEM] is trying to suggest that the EIA gas forecast is correct – but their power forecast is understated."
>
> (Exhibit C19-11, Fulton, p. 6)

In the examination of the Energy Price Risk, Mr. Fulton refers to spot and near month values from January 2002 to December 2004 (Exhibit C19-11, Fulton, p. 7). Mr. Fulton observes that "the relative liquidity of forward energy price curves makes their use somewhat questionable." Mr. Fulton suggests that:

> "The relevant issue is which power and gas forecasts should be used for assessing the potential financial performance of the proposed DPP facility and the risk implications for the EPA – the economists forecasts or the exchange prices from public markets."
>
> (Exhibit C19-11, Fulton, p. 10)

Mr. Fulton uses forward price curves though the year 2010 in the examination of the Utilization Risk, and uses the Mid-C forward curve to calculate a 24.4 percent utilization factor. Mr. Fulton states:

> "Unless we see a significant change in the fundamentals in the Pacific Northwest power market it is difficult to envision the proposed DPP [plant] operating more than 20% to 30% of the time with positive energy margins, given the potential higher cost to land gas at the facility than would be the case for a Facility located at Sumas."
>
> (Exhibit C19-11, Fulton, p. 15)

7.2.3 BC Hydro Rebuttal Evidence

BC Hydro called a Rebuttal Panel that included Mr. Lauckhart of Global Energy Advisors (also known as Henwood Consulting) and Dr. Pickel of Charles River Associates.

Mr. Lauckhart and Dr. Pickel independently forecast MHRs for the DPP plant. Mr. Lauckhart forecast a higher heat rate than calculated from the 100 percent Capital Cost Recovery case, and Dr. Pickel forecast for 2008 and 2012 MHRs very close to those calculated from the average of the 100 percent Capital Cost Recovery and 25 percent Capital Cost Recovery case of BC Hydro (T14: 3004).

Global Energy Advisors use the "Henwood model" which focuses on the specific loads and resources that are expected to be in place in the Western Electricity Coordinating Council ("WECC") region in each hour of the year that the EPA will be in effect (Exhibit B-97, Lauckhart Rebuttal Evidence, p. 3). Mr. Lauckhart states that the EIA power price forecast used by Mr. Fulton is the generation component of a cost-based retail electricity price forecast and that it is not specific to northwest or WECC markets (Exhibit B-97, Lauckhart Rebuttal Evidence, p. 2). With respect to Mr. Fulton using historic market prices from January 2002 to December 2004, Mr. Lauckhart states that this data is not reflective of the conditions that are expected to occur from 2008-2033. However, BC Hydro (Mr. O'Riley) stated that this period is "a really good example to show what the role of gas plays in electricity prices" (T15: 3159). Mr. Fulton accepts that the analysis needs to use all of the last five years of market data (T12: 2554).

Charles River Associates use the "GE-MAPS" model which, like the Henwood model, calculates plant dispatch using an hourly simulation of generation and transmission throughout the WECC. For both the GE-MAPS model and the Henwood model, electricity prices result from hourly simulation. Dr Pickel, states that the correct way to accomplish a capacity factor analysis is through greater time detail, such as an hourly analysis, and geographic specificity (Exhibit B-97, Pickel Rebuttal Evidence, p. 3).

For both the Henwood model and the GE-MAPS model, the marginal operating resource in most hours of the year in the WECC is a resource fueled by natural gas. Therefore, an efficient gas-fired unit has a good opportunity to be operated at a fairly high capacity factor (Exhibit B-97, Lauckhart Rebuttal Evidence, p. 11).

Both Henwood Consulting and Charles River Associates used the same price assumptions, although using an hourly shape, as used by the JIESC expert to calculate a capacity factor and operating revenue for the DPP plant. Both Henwood and Charles River Associates reached dramatically different conclusions on the capacity factor from those of the JIESC expert. The capacity factor forecast by Charles River Associates was 78.0 percent in 2008 and 83.2 percent in 2012 (Exhibit B-97, Pickel Rebuttal Evidence, p. 10), and the capacity factor forecast by Henwood was 77 percent in 2008 and 91 percent in 2012 (Exhibit B-97, Lauckhart Rebuttal Evidence, p. 15). As stated above, the capacity factor estimates of Mr. Fulton are under 30 percent.

7.2.4 Market Heat Rates

MHRs are driven by market fundamentals. The evidence of Mr. Fulton indicates an increase in the MHR that is calculated from the current forward market prices for the period through 2010 (Exhibit C19-11, Fulton, Figure 6, p. 10). The evidence of BC Hydro's expert witnesses also indicates an increase in the heat rate (Exhibit 81A). The point of departure is not an increase in heat rates, but the magnitude of that increase in the long-term forecast of MHRs.

Both BC Hydro and the JIESC are of the view that MHRs for the last three years would not support a new combined-cycle gas turbine plant (T15: 3137). BC Hydro believes, however, that the MHRs between 2002 to 2004 are not sustainable given a view to market fundamentals (T14: 3004). The market evidence over the period 2002-2004 suggests that gas is still on the margin, but during this time the fleet of resources and the load drove to a very low heat rate due to surplus capacity in the WECC (T15: 3172-3173). As stated by BC Hydro, MHRs in four of last seven years are considerably higher than any of the forecast MHRs (T14: 3004) The result of the BC Hydro expert analysis is that gas-fired generation is driving electricity price in the west (T15: 3157). Over time it is expected that new generation will be needed to meet load growth and retirements so MHRs will increase so that gas-fired generation will recover fixed and variable costs (T14: 2983; T15: 3174).

The risk to be borne by customers is that MHRs do not rise to a level that recovers the fixed and variable costs of natural gas generation at the margin; that is, gas does not drive long-term electricity prices. With the full recovery scenario, BC Hydro assumes that new generation in the WECC will be gas-fired generation (T15: 3171), and MHRs are expected to reflect the long-run marginal cost of a gas turbine. With the partial recovery scenario, BC Hydro assumes that gas does not drive electricity prices. With the full recovery scenario, the capacity factor for the DPP plant is 87 percent and for the partial recovery scenario, the capacity factor is 77 percent. Also, the expert evidence of BC Hydro is that the capacity factor is not necessarily a good indicator of the value of a plant (Exhibit B-97, Lauckhart Rebuttal Evidence, p. 14).

7.2.5 Use of Market Information

Although both the GE-MAPS and Henwood models use market fundamentals to forecast where no market transactions are available, the experts of both BC Hydro and the JIESC agree that forecasts should be checked against market prices (T15: 3150, 3154). One point of departure is the view of the experts with respect to the availability of market prices. Mr. Fulton states that prices for transactions are available out to 2012 (T12: 2565). Dr. Pickel states that beyond two and three years, the market is not liquid enough to rely on for evaluations (T15: 3152). Mr. Lauckhart compares market prices for 2002-2004 to the forward curves in Exhibit 81A, which are rising from current prices but are consistent with current prices (T15: 3154).

7.2.6 Huntington/Sumas vs. Station 2

BC Hydro plans to buy gas for the Island Cogeneration Plant ("ICP") and the DPP plant under a portfolio of gas commodity arrangements that will include purchases at Huntingdon/Sumas and Station 2. The JIESC states that the market is moving from Sumas to Station 2 as producers and marketers release transmission-south capacity of Duke Energy Gas Transmission (Exhibit C19-11, Guenther, p. 4). BC Hydro believes that Huntingdon/Sumas is sufficiently liquid to execute transactions, and that it would only purchase at Station 2 if overall that would overall lower gas purchasing cost or risk (BC Hydro Argument, p. 22). TGVI agrees with BC Hydro's assertion regarding liquidity at Huntingdon/Sumas (TGVI Argument, p. 9).

7.3 Commission Panel Determination

For the purposes of this Decision it is necessary to forecast prices for the term of the EPA. **The Commission Panel accepts the use of the EIA gas price forecast for the evaluation of CFT bids and possible CFT alternatives.** However, the Panel also notes that in this particular instance, the results of the CFT are more sensitive to the market heat rate, which is a function of the electricity forecast, than the underlying gas price forecast.

For forecasting electricity prices, the Commission Panel prefers the results of the Henwood and GE-MAPS models to the results of the analysis of Mr. Fulton. The Henwood and GE-MAPS models are forecasting models that are generally accepted in the industry. The Commission Panel accepts that the capacity factor of a dispatchable plant needs to be determined using hourly price forecasts. Although the

Commission Panel acknowledges that market data can provide a valuable reference point for forecasts, the limited liquidity of markets beyond two to three years significantly limits the use of market data in long-term forecasts and planning.

The Commission Panel accepts the evidence of the BC Hydro Rebuttal Panel as to the forecast of MHRs and the DPP plant capacity factor. The Commission Panel does not accept the submissions of the JIESC that rely on the EIA electricity price forecast for the calculation of capacity factors. The Commission Panel also does not accept that actual prices from January 2002 through December 2004 establish a reasonable expectation as to long-term prices, and the Commission Panel accepts that over-supply and under-supply situations can be expected to occur in the period 2008-2020.

The Commission Panel concludes that it is likely that gas prices will drive power prices in the WECC for most, if not all, of the term of the EPA. Further, the Commission Panel accepts that MHRs experienced during January 2002 through December 2004 may occur again during the term of the EPA. However, the Commission Panel also accepts that in the long-term MHRs will tend to be consistent with the conversion assumptions in the QEM model for the full recovery scenario. The Commission Panel also accepts that the partial recovery scenario, and by extension the 50/50 weighting of the full and partial recovery scenarios, is a conservative forecast of power price forecasts.

8.0 GAS TRANSPORTATION RISK

By entering into the EPA for a gas-fired tolling project, BC Hydro assumed two responsibilities and the associated risks related to gas transportation. The first, more critical responsibility is for the physical supply of the gas commodity to the DPP plant. The second is for the cost of transporting the gas to the facility (as distinct from the cost of the gas commodity itself, which was considered in previous Chapters).

8.1 Gas Transportation Availability Risk

The Commission Panel determined that gas availability risk is not within the scope of this proceeding, but stated that BC Hydro has the burden of establishing that gas transportation service will be available to the DPP plant. The Commission Panel stated that gas transportation agreements may not be necessary to establish availability of gas transportation (T2: 313).

BC Hydro clearly stated that in the CFT it was looking for a long-term solution to resolve its long-term capacity shortfall problem on Vancouver Island, to replace a long-term asset that had been there for 50 years (T6: 1098-1099). BC Hydro expects that it will enter into a firm transportation service agreement with TGVI by November 2005, although it may not be a long-term agreement (T7: 1395-1397). BC Hydro argues that the Commission can compel TGVI to provide such service, and that there is a very low risk of not being able to obtain gas for the DPP plant (BC Hydro Argument, pp. 22-23). BC Hydro based its position, in part, on the precedents of its short-term agreements for gas transportation to ICP (Exhibit B-9, BCUC IR 1.23.4). DPP makes similar submissions (DPP Argument, p. 9). If there were to be a need for a short-term bridging arrangement for winter 2007/08, BC Hydro stated that it is prepared to fund the additional costs that may result from such a short-term solution (T8: 1686-1687).

TGVI responds by referring to its key milestone schedule for the LNG project, which indicates that approvals for its LNG project were needed by February 28, 2005, so that work on the LNG facility can proceed in March 2005, in order to ensure firm service to the DPP plant for the winter of 2007/08 (Exhibit C18-2). TGVI states that BC Hydro will need to expeditiously enter into a long-term transportation arrangement with it. TGVI notes that the CFT process sought a long-term reliable solution for the capacity problem on Vancouver Island, and argues that a dependable generation facility must be accompanied by corresponding reliability in its gas transportation arrangements. TGVI notes that the Georgia Strait Crossing ("GSX") project has been terminated, and that the short-term transportation agreements for ICP were put in place to provide service until the GSX pipeline went into service. TGVI disagrees that the ICP agreements establish a precedent for the DPP plant. Furthermore, TGVI notes that a delay in putting long-term transportation arrangements into place may result in a delay in meeting the requirements of the DPP plant or may result in a sub-optimal portfolio of expansion facilities being put into place, and that any such incremental costs were not included by BC Hydro in the CFT evaluation. TGVI confirms that it will be able to provide firm transportation to ICP and the DPP plant at the costs used by BC Hydro in the CFT evaluation, provided BC Hydro promptly enters into a long-term service agreement (TGVI Argument, pp. 3-10).

The JIESC states that BC Hydro's evidence about LNG or dual-fired generation at the DPP plant as potential backup options was weak, and argues that firm service agreements with TGVI are important and must be in place prior to approval of a project. The JIESC also notes that the TGVI system delivering gas to Vancouver Island is a high pressure pipeline traveling through difficult terrain and under water, and so is not free of risks (JIESC Argument, pp. 17, 29).

NorskeCanada notes that there is a dispute between BC Hydro and TGVI about the appropriateness of tolls and the term of the transportation service agreement. NorskeCanada states that BC Hydro should have provided some measure of the risk and costs of the options it identified to fuel the DPP plant in the event it does not secure transportation, and argues that the Commission Panel should consider the lack of a transportation agreement to be a significant risk when assessing the EPA (NorskeCanada Argument, pp. 15, 17). BCOAPO notes that November 2005 is well past the point-of-no-return for the DPP plant, and argues that it would not be appropriate that a 25-year facility, that was being built to cover one year of a projected peak capacity deficiency, could be operating on an interruptible gas supply for that year (BCOAPO Argument, p. 16).

Several other Intervenors also argue that the lack of a gas transportation service agreement exposes BC Hydro ratepayers to risks in terms of both reliability of supply and costs (Shadybrook Farm Argument, Section E; Gabriola Ratepayers Argument, Section 5; McLennan Argument, p. 5; Gold River Argument, Fuel Price Risk).

In its Reply, BC Hydro responds that it considers a worst case scenario would be that a transportation service agreement would not be in place until November 2005. While an LNG facility would then not be possible for 2007, compression expansion could be completed to ensure firm service would be available to the DPP plant for winter 2007/08. BC Hydro states that TGVI should be able to provide at least 30 to

40 TJ/d of firm capacity for 2007/08, so that the DPP plant would be able to produce at least 150 MW of dependable capacity (BC Hydro Reply, pp. 12, 14). DPP notes that TGVI is willing to provide transportation service and BC Hydro has recourse to the Commission. It submits that the lack of a transportation agreement should not be a concern to the Commission (DPP Reply, p. 10).

The DPP plant requires a reliable supply of fuel to provide a reliable supply of capacity. The Commission Panel considers that dual fuel capability and offshore LNG are no more than remote possibilities for the winter of 2007/08. Considering the importance that BC Hydro attaches to having reliable generation for 2007/08, and its willingness to enter into a 25-year EPA with large annual fixed charges, it is not clear why BC Hydro should be reluctant to commit to a long-term firm transportation agreement with TGVI.

The gas demand for the DPP plant and for ICP represents a considerable portion of the firm load on the TGVI system. There is broad acknowledgement that TGVI will have to significantly expand its system to meet the needs of both the DPP plant and ICP. Moreover, since BC Hydro intends to rely on capacity from ICP (T8: 1694), natural gas supply to that facility is also critical (recognizing that the ICP has certain limited dual fuel capability) (BC Hydro Reply, p. 13). The Commission Panel concludes that in order for TGVI to plan the expansion of its system so as to provide reliable service at the lowest long-term cost, it needs to know how much firm gas transportation capacity BC Hydro will require and is prepared to commit to pay for.

The Commission Panel is not persuaded that ad hoc short-term gas transportation arrangements are adequate, or compatible with a 25-year EPA that is to provide long-term, dependable generation capacity. Also, BC Hydro has certain rights of termination under Section 3.1 of the EPA. **Any acceptance of the EPA by the Commission Panel will be subject to BC Hydro purchasing firm gas transportation service from TGVI to serve the DPP plant and, within 45 days of the date of the Order accepting the EPA, BC Hydro entering into and facilitating the filing with the Commission of a long-term firm gas transportation service agreement with TGVI to serve both the DPP plant and the ICP.**

8.2 Gas Transportation Cost Risk

The Commission Panel determined that gas transportation costs are relevant to the proceeding, and that the onus is on BC Hydro to provide evidence to support the gas transportation costs used in the QEM (T2: 313).

BC Hydro estimated the present value of TGVI service to transport gas to the DPP plant as $131.6 million in 2006 dollars, based on information provided by TGVI (Exhibit B-9, BCUC IR 1.23.5; Exhibit B-16, BCUC IR 2.47.1; T8: 1700). BC Hydro selected the tolling scenario which assumed that the revenue to cost ratio for its rates decreased from 1.25 to 1.10 after 2011. In his written evidence, Mr. Simpson of BC Hydro Panel 2 stated that, as a result of a recent reduction in the contract demand for the Vancouver Island Gas Joint Venture ("VIGJV"), TGVI tolls for the DPP plant would increase by approximately $1 million per year, or less than $10 million on a present value basis (Exhibit B-35, Simpson Evidence, Question 9; T6: 1210).

In his evidence, Mr. Guenther on behalf of the JIESC identified three cost elements that he felt BC Hydro had not factored into its project evaluation:

- LNG facility related costs and pipeline costs;
- Termination of Royalty Credits on natural gas supply; and
- Repayable government loans.

Mr. Guenther estimated that, assuming Revenue Deficiency Deferral Account payments will have ended, TGVI may experience a $30.9 million per year increase in costs after 2011 (Exhibit C19-11, p. 5). In his testimony, he clarified that these elements were included in the TGVI costs that TGVI used to develop indicative tolls for BC Hydro. However, he felt that under the "soft cap" or competitive rate approach, to the degree there is no competitive room to recover all these costs, BC Hydro and other transportation customers may be targeted to recover this revenue requirement and the corresponding risk was not reflected in the indicative toll for the DPP plant (T12: 2523-2534).

The JIESC argues that some or all of the cost increases identified by Mr. Guenther, and toll increases from decontracting, may come to rest on BC Hydro and that some allowance for that risk should be included in the QEM and Cost Effectiveness analyses (JIESC Argument, pp. 27, 29). The JIESC presents a Cost Competitiveness comparison that includes an adjustment of $114 million present value as a credit to the Tier 2 and No Award options, on the basis that these TGVI costs may be incurred by the Tier 1 option (the adjustment was described as “TGVI Toll Increase after 2011 @ 50% to BCH DPP EPA”). The JIESC Cost Competitiveness comparison also includes a $10 million adjustment for the TGVI toll increase due to VIGJV decontracting (JIESC Argument, pp. 34, 35).

TGVI and BC Hydro argue that the risks associated with the Royalty Credits and government loan repayments already exist with respect to transportation service to ICP, and do not increase with the DPP plant (TGVI Argument, p. 6; BC Hydro Reply, p. 14).

A number of other Intervenors express concern about the gas transportation cost risk that BC Hydro assumed in the EPA, without a corresponding acknowledgement of the risk in the financial analyses (NorskeCanada Argument, pp. 16, 17; BCOAPO Argument, pp. 15, 16; Green Island Argument, p. 15; CEC Argument, p. 12).

The Commission Panel concludes that providing gas transportation to the DPP plant represents a cost risk for BC Hydro. The $10 million identified in the Evidence of Mr. Simpson is material and should be incorporated into the results of the QEM and the Cost-Effectiveness analysis. The Commission Panel accepts that there are further TGVI toll risks, but is not persuaded that a reasonable adjustment for them would of the order of magnitude that was proposed by the JIESC. Uncertainties related to gas prices would appear to be considerably greater than those associated with gas transportation tolls. Moreover, while the relative uncertainty may be somewhat greater, the cost of TGVI transportation will be considerably less than the payments to DPP under the EPA. **The Commission Panel concludes that gas transportation cost risk is a real, but comparatively small, component of the overall risk profile for the EPA.**

9.0 VIGP ASSET CREDIT

9.1 VIGP Asset Transfer Credit Amount

The VIGP Transfer Agreement provides for the sale by BC Hydro of the VIGP assets to DPP for $50 million. BC Hydro established the asset transfer price on the assumption that a developer of the VIGP project would otherwise need to secure a site, a steam turbine, engineering design, First Nations benefit agreements, water and effluent services agreements, environmental assessment certificate, and air emission permits. In addition, absent the transfer of the assets, a developer would assume permitting risk by incurring development costs with the possibility that the permits would not be granted (Exhibit B-9, BCUC IR 1.16.1). Table 9.1 shows a breakdown of the price (Exhibit B-1, Appendix C).

Table 9.1
VGIP Asset Transfer Price

Cost of steam turbine	$25,343,007
Project site	1,667,691
BC Hydro cost to secure permits	4,716,699
BC Hydro cost of interconnection study	140,598
Risk Reduction Premium or development fee	18,132,005
	$50,000,000

The BC Hydro costs include direct costs and BC Hydro corporate overheads but exclude carrying costs. In response to questions during the CFT process, BC Hydro explained that it set the value of the VIGP assets so as to ensure that ratepayers realize the full value of the assets and to ensure this value is not transferred to bidders at the expense of ratepayers (Exhibit B-61, p. 2). BC Hydro stated that the Risk Reduction Premium of $18 million was added to reflect the premium that a developer may extract for a similar project brought to a similar point of development. The Utility stated that the amount is within the range observed for power plant developers in North America, but offered no evidence in support of the statement. BC Hydro stated that the fee also considered that the successful proponent would secure a 25-year EPA and would not be required to assume gas supply risk (Exhibit B-1, Appendix C).

Total BC Hydro costs as of July 2003 for VIGP assets were $65,234,936, including $31.5 million of gas turbine expenditures (Exhibit B-1, Appendix C). BC Hydro estimated the salvage value of the VIGP assets at $14 million (Exhibit B-9, BCUC IR 1.16.2).

BC Hydro argues that the payment for the VIGP assets is a real benefit and not a subsidy, but did not address the quantum of the VIGP asset price (BC Hydro Reply, p. 20).

GSXCCC et al. argue that the pricing of the VIGP assets in the CFT is an explicit subsidy of VIGP projects bid into the CFT, with the amount of the subsidy being the difference between the $50 million price and the value of the VIGP assets to the bidder. GSXCCC et al. argue that this subsidy was effective since all the portfolios evaluated in the QEM included the VIGP assets (GSXCCC et al. Argument, p. 2). CEC argues that BC Hydro offered the VIGP assets as a free contribution in the CFT process, since the EPA requires customers to repay DPP for the price of the assets in the EPA capacity charges. However, CEC's arguments largely go to BC Hydro's proposed accounting treatment of the VIGP asset payment rather than the amount of the payment (CEC Argument, p. 3).

The Commission Panel is of the view that a preferred, market-oriented method for establishing the value of the VIGP assets would have been to permit CFT participants to bid what they wished for the assets, subject to a reserve price set by BC Hydro. The bids that BC Hydro received under the terms of the CFT provide little information about the market value that bidders actually placed on the VIPG assets. In particular, the stated credit for gas supply risk is not transparent, and it is not clear how ratepayers will realize any such net benefit when payments to DPP under the EPA are taken into consideration. On the other hand, the Commission Panel is not persuaded by the arguments of GSXCCC et al. that the fact that all QEM portfolios included VIGP assets is evidence that the $50 million price represents a subsidy. While the asset price did not include an identified cost for developing the engineering design specifications, the $18 million Risk Reduction Premium is a significant amount. **The Commission Panel accepts the price of $50 million as fair value for the VIGP assets.**

9.2 VIGP Asset Transfer Credit Treatment

In BC Hydro's view, by applying the $50 million payment from DPP under the VIGP Transfer Agreement, the Utility reduces the amount of ratepayer risk for VIGP assets from $67 million to $17 million (T16: 3316-3317). BC Hydro considers the value of $50 million is real, stating that once the $50 million was received, "from an accounting perspective, you can't say those assets don't have value" (T16: 3320) and suggests that the shareholder can seek to recover the $17 million if it can be demonstrated that the costs were prudently incurred (T16: 3323).

The JIESC submits that the payment results from the ratepayer committing to pay charges under the EPA that are high enough that DPP is prepared to pay $50 million for the VIGP assets. The JIESC considers that the $50 million payment takes the shareholder off the hook for those costs and does not benefit the ratepayer (T16: 3328). CEC expresses a similar view as the JIESC (T16: 3330).

CEC states that offsetting the VIGP development costs with the $50 million payment would be a violation of Commission Order No. G-54-04 (CEC Argument, p. 7; T16: 3331). CEC considers that the issue could be partially addressed by allowing for Commission review of the $67 million of VIGP development costs and disaggregating the $50 million payment for possible return to the customers (T16: 3333-3334). BC Hydro responded that it would not stand in the way of maintaining the $67 million in the deferral account (T16: 3337).

The Commission Panel finds that the $67 million of VIGP development costs should be available for separate review as contemplated by Commission Order No. G-54-04. Accordingly, the Commission Panel directs BC Hydro to carry forward, in a designated deferral account, the $50 million payment received from Duke Point Power under the VIGP Transfer Agreement, together with any carrying charges associated with that payment until BC Hydro has made an application providing for the manner of the disposition of the payment and the Commission has made a determination thereon. This designated account is to be separate from the designated account approved by Commission Order No. G-54-04. The application for disposition is to be made concurrently with the application contemplated by Commission Order No. G-54-04.

10.0 THE EPA TERMS AND CONDITIONS

10.1 Overview of the EPA Development Process and Term

The purpose of the EPA, as broadly stated in Schedule A from the VIGP proceeding, was to contract with one or more IPPs for “20 years supply of dependable electrical capacity of a minimum of 240 MW in aggregate on Vancouver Island and associated energy (if any), with a commercial operation date on or before November 2006” (Exhibit B-1, Appendix A, p. 40).

During the CFT process, a first pro-forma EPA was publicly posted on October 31, 2003, a Final Form EPA was issued June 23, 2004, and a Revised Final Form EPA was issued July 30, 2004 to pre-qualified bidders with some corrections and clarifications, and dealing with certain bidder issues.

During the CFT process, a number of other changes were made to the EPA. For example, the Commercial Operation Date was later revised to May 1, 2007. The term was changed from 10 to 25 years at the bidder’s discretion, to a mandatory minimum term of 25 years with a unilateral right of BC Hydro to extend the term by up to ten additional years (EPA Clause 2.2; Exhibit B-1, Appendix G).

A summary of key changes to the EPA and the VIGP Transfer Agreement that were made during the development of the EPA in response to comments from bidders is contained in Appendix M of the CFT Report (Exhibit B-1, p. 24, Tab M).

A Revised Final Form EPA was filed in Exhibit B-1, Tab N, and a very brief description of it is included in the CFT Report (Exhibit B-1, p. 24). Portions of the EPA were made public by letter dated January 11, 2005 (Exhibit C17-8), except certain sections of Appendices 3, 5 and 9.

In its letter of January 23, 2004, the Commission advised BC Hydro regarding this CFT that “The Commission Panel will be concerned if such requirements are more stringent or less flexible than the minimums that are needed, thereby increasing costs for ratepayers by disqualifying otherwise worthwhile projects or by increasing bid prices” (Exhibit B-1, Appendix F, p. 6).

10.2 Views of the Participants

In Exhibit B-1, Appendix A, Schedule A, a document which preceded the CFT issue, BC Hydro states in Section 1.2 that the CFT "contract terms will be generally consistent with commercial and legal terms and conditions in long-term supply arrangements used by other utilities in procuring electrical capacity and energy, recognizing however the critical nature and timing of the need for new Vancouver Island supply". The onus was on BC Hydro to demonstrate that it produced appropriate EPA terms and conditions given its obligation to serve customers on Vancouver Island.

BC Hydro claims that "…[t]here is no evidence that CFT terms discouraged participation by bidders with projects meeting BC Hydro's needs", however, BC Hydro also acknowledges that a "…high reliability standard did render some alternative energy sources, such as wind, solar, and tidal, as being unable to compete" (BC Hydro Argument, pp. 26, 27). BC Hydro also claims that the various financial incentives provide ample protection against DPP performance risk (BC Hydro Argument, pp. 14, 15). With respect to contract term, BC Hydro claims that the characterization of the EPA as a 35-year contract is false due to certain terms in the extension period favourable, in their view, to the bidder, and that the issue of tenure extension is a "red herring" (BC Hydro Reply, p. 18).

No bidder, excepting Green Island, offered evidence that the terms and conditions were inappropriate. There is, however, some evidence that a few bidders exited the CFT, apparently finding the EPA terms too onerous (Exhibit B-12, GSXCCC IR 1.12.1; Exhibit B-16, BCUC IR 2.61.8). At least one of these bidders was a substantial corporation (Exhibit B-16, BCUC IR 2.61.8).

Green Island, in its responses to BCUC IRs 1.1 and 1.2, explained that its biomass project was hampered by the EPA restrictions in the operating range from 95-105 percent, in terms of allowance for third party sales, and that had Green Island been given an allowance for ambient conditions as afforded gas turbine plants, its operating range would have increased to perhaps 90-110 percent (Exhibit C9-18). Green Island claimed that its ability to sell power to third parties was hampered or devalued by a number of EPA terms. The 97 percent availability requirement of the EPA, in its view, provided a bias in favour of gas turbine plants (Exhibit C9-16, DPP IR 5.1).

10.3 Commission Panel Determination

The Commission Panel recognizes that this EPA is somewhat unique in that it arises out of a call for dependable capacity and is intended to offer a generation solution with an equivalent reliability to that of a transmission line.

The Commission Panel is encouraged by the flexibility that BC Hydro showed with respect to some terms and conditions of the EPA. As demonstrated in the summary of key changes (Exhibit B-1, Appendix M), BC Hydro worked with bidders and made significant changes to the EPA, with many changes in favour of bidders.

The Commission Panel also notes that, despite concerns raised with some terms and conditions, the EPA has been executed and the winning project is significantly lower cost than the VIGP benchmark.

The Commission Panel finds no evidence that the terms of the particular EPA in this proceeding, including risk allocation, are unreasonable, and finds that they meet the objectives specified in Schedule A in terms of accommodating as wide a range of technologies as practical. However, prior to executing future EPA's, BC Hydro is encouraged to give further consideration to whether its contract terms are consistent with those of other utilities.

Although the evidence in this proceeding does not confirm the executed EPA will result in a premium for customers, the Commission Panel is still concerned that in other circumstances ratepayers could bear an unjustifiable premium due to unduly stringent terms in the EPA. In reviewing terms and conditions for inclusion in future EPAs, BC Hydro should consider at a minimum provisions dealing with risk allocation, term and renewal, required availability, change-in-law, limits of liability, liquidated damages levels, and liability for emissions.

Prior to, or as part of, its next dependable capacity CFT, the Commission also expects BC Hydro to review with stakeholders the detailed procedures and policies it has adopted to determine the dependable capacity of different types of generation such as gas-fired, coal-fired, cogeneration, hydroelectric, wind and biomass generating units. If various technologies may be incapable of meeting the terms of a capacity CFT, the Commission will expect convincing evidence that CFT design objectives cannot reasonably accommodate such technologies.

In its October 29, 2004 Decision, the Commission suggested that if BC Hydro desires an efficient and effective regulatory process, it is incumbent upon BC Hydro to design its competitive processes so that there is a reasonable opportunity for the Commission to comment on the terms and conditions of EPAs prior to the awarding of contracts. The Commission Panel suggests that the REAP, ROR and IEP filings, and review processes may provide an appropriate forum for such a review.

One concern is how risks are allocated between the buyer and seller, including risks such as change in law, availability and reliability, Commercial Operation Date, construction and operation cost and risk, fuel price and supply risk, liabilities, and power price. In determining how risks should be allocated in the EPA, some important considerations may include: (a) who can best reduce or eliminate the risk; (b) who can best absorb or mitigate the risk; and (c) who would have borne the risk had the proponent done the project itself. BC Hydro appears to recognize this opportunity to improve the ratepayer position (T6: 1089; T8: 1736; Exhibit B-9, BCUC IR 1.17.1). However, BC Hydro offered little evidence as to how, or on what basis, it decided to apportion the most challenging risks, with the exception of an explanation regarding gas supply risk (Exhibit B-9, BCUC IR 1.17.1).

The Commission Panel has little evidence before it on this matter, but is concerned that it is not in the economic interests of ratepayers to apportion general change-in-law, and GHG and similar risks to a single purpose company/project such as DPP. The Commission Panel notes, for example, that some of BC Hydro’s contracts have contained change-in-law protection for bidders [Exhibit B-18, Gold River IR 1.5.32 (v)], but that the DPP EPA leaves change-in-law risk with the bidder (T7: 1477). At the same time, the Commission Panel also notes BC Hydro’s explanation for its approach to the change-in-law provision and its suggestion that the approach in the EPA was not exceptional, particularly in mature political and commercial jurisdictions [Exhibit B-18, Gold River IR 1.5.3.2(i)].

11.0 DUKE POINT POWER LIMITED PARTNERSHIP

11.1 Description of Tier 1 Outcome

Under the terms of BC Hydro's CFT, the portfolio with the lowest NPV was a proposed single 252 MW dispatchable gas-fired combined cycle power plant located at the site of BC Hydro's proposed VIGP near the Duke Point industrial area of Nanaimo, B.C. This winning bid is referred to as the "Tier 1" outcome.

The DPP plant will be owned by DPP, a single purpose entity formed for the purpose of bidding the project. DPP will also construct and operate the DPP plant. The General Partner will be Bastion Island Power Inc. ("BIPI") and this entity will manage the affairs of the Limited Partnership.

DPP is owned directly by three entities – Macquarie Essential Assets Partnership ("MEAP"), a group of private investors, and Pristine Power Inc. – collectively known as the Pristine Group. MEAP is managed by a wholly-owned subsidiary of Macquarie Bank Limited ("Macquarie"). MEAP owns 60 percent of the DPP plant. The private investors and Pristine Power will own the remaining partnership interests. Pristine Power originated the DPP bid and is the Asset Manager, in addition to having a direct ownership interest of 10 percent of the venture.

DPP has elected to purchase the VIGP assets from BC Hydro under the terms put forward in the CFT. DPP plans to commence construction of the plant in March 2005 and expects to achieve commercial operation by May 2007. The EPA between BC Hydro and DPP was fully executed on November 16, 2004.

The plant is comprised of the following major components (Exhibit C17-8):

- One "F" class gas-fired combustion turbine rated nominal 167 MW equipped with dry low NOx and low carbon monoxide combustors;
- A single 128 MW condensing steam turbine;
- A heat recovery steam generator with supplementary duct-firing capability and selective catalytic reduction to limit NOx emissions to 3.5 ppmv;
- A surface condenser, cooling water circuit and wet cooling tower;
- Outdoor sound attenuated enclosures for the combustion turbine and steam turbine;
- Electrical structures, switchgear and protective relaying;

- Auxiliaries for major and balance of plant equipment;
- Wastewater collection system;
- Sanitary sewage treatment unit;
- Fuel gas supply line from Terasen Gas main pipeline; and
- 138 kV connection to BC Hydro system.

11.2 Pricing Terms

Pricing terms are described in Appendix 3 of the EPA (Exhibit B-19). Under the EPA, DPP will be compensated through the following monthly payments:

- Capacity Charge Payment;
- Operations and Maintenance Cost Payment;
- Energy Charge Payment;
- Start-Up Payment; and
- Availability Adjustment (if applicable).

The monthly Capacity Charge Payment is $12,029.17/MW based on demonstrated capacity prorated for any hours during the month in which the Seller invokes Force Majeure. The monthly Operations and Maintenance Cost Payment is $2,573.63/MW based on demonstrated capacity, escalated at the rate of the Consumer Price Index during the term of the EPA. The Energy Charges Payment is $2.73/MW.h based on eligible energy, escalated at the Consumer Price Index during the term of the EPA. The Start-Up Payment is based on the number of hot, warm and cold starts in the month. The Start-Up Payment was not disclosed as part of the public record for this hearing but was provided in confidence to the Commission (Confidential Exhibit B-4). The Availability Adjustment is a penalty of $250/MW based for the extent to which the monthly availability factor is less than 97 percent.

11.3 Rate Impacts

BC Hydro included an analysis of the incremental rate impact of the DPP plant with its filing (CFT Report, Section 6.0, pp. 21, 22). The analysis indicates an incremental rate impact of 2.2 percent in F2008, declining to 1.7 percent in F2011. The rate impact analysis excludes the transfer value of the VIGP assets. For comparison, the incremental rate impact of the VIGP benchmark (i.e., excluding sunk costs) would be 2.3 percent in F2008, declining to 1.8 percent in F2011. Including sunk costs, the total rate impact of the VIGP benchmark would be 2.5 percent in F2008 declining to 2.0 percent in F2011.

11.4 Comparison with VIGP Benchmark

As bid, the DPP plant has a Net Portfolio Cost of $50 million lower than the VIGP benchmark. However, the DPP bid includes a $50 million payment for the existing VIGP assets. As suggested in the VIGP Decision (p. 82), the VIGP benchmark does not include sunk costs but only reflects the incremental costs to complete the plant (Exhibit B-9, BCUC IR 1.16.3). The DPP bid, on the other hand, includes a $50 million payment for the existing assets. Deducting this payment from DPP's bid, the incremental cost of the DPP plant is about $100 million lower than the incremental cost of the VIGP benchmark (Exhibit B-12, BCOAPO IR 1.10.2). The primary reason for the difference in NPV costs between the VIGP benchmark and the DPP plant is attributed to lower operations and maintenance charges and energy charges of the DPP bid (Exhibit B-12, GSXCCC et al. IR 1.19.1).

There was considerable discussion in the hearing and Argument regarding the application of the credit for transfer of the VIGP assets. However, all of the possible Tier 1 outcomes included the VIGP election. As a result, removal of the credit would not alter the Tier 1 outcome of the CFT. **The Commission Panel accepts BC Hydro's analysis that the winning Tier 1 bid has a lower cost than the incremental cost of the VIGP Benchmark.**

11.5 Comparison with Other Tenders

As part of the filing, BC Hydro provided a confidential copy of the populated QEM comparing the tenders and portfolios that were evaluated in the QEM. This filing included the calculation of the Net Tender Cost for all six accepted tenders and VIGP benchmark under both electricity price forecasts, and the calculation of the Net Portfolio Cost for the five portfolios consisting of projects or combinations of projects with a total capacity of between 150 and 300 MW. A confidential summary of the Net Tender Costs for each tender was also provided in BC Hydro's response to BCUC IR 2.72.1 (Confidential Exhibit B-15). These filings confirmed the selected Tier 1 project had the lowest NPV of the five portfolios considered in the QEM.

In response to an undertaking requested by Gold River (T9: 2133-2142), BC Hydro also provided a confidential analysis of the Tier 2 portfolio using the QEM (Confidential Exhibit B-103). This Tier 2 portfolio consists of the 75 MW Green Island Biomass Plant and a 47 MW peaking plant, totalling 122 MW of capacity, which was less than the Tier 1 threshold established in the CFT process. This filing shows that the Tier 2 portfolio has a lower NPV than the original five portfolios evaluated in the QEM. However, given the lower capacity provided by the Tier 2 portfolio, this analysis also shows that Tier 2 has the highest net cost of the six portfolios on an NPV/MW and NPV/MW.h basis.

11.6 Selection of the DPP Plant without Duct-Firing

An issue emerged during the hearing concerning the selection criterion in the QEM for the winning Tier 1 bid. Specifically, the Chair observed, and BC Hydro witnesses agreed, that among the possible Tier 1 outcomes, the DPP bid with duct-firing appeared to offer better value for customers than the DPP bid without duct-firing. This observation was based on comparing the Net Portfolio Cost per MW of capacity as calculated by the model. In contrast, the winning bid was selected on the basis of the lowest absolute NPV among portfolios totalling between 150 and 300 MW.

Views of BC Hydro and DPP

BC Hydro argued that the minimum portfolio size reflected its understanding of the VIGP Decision and the January 23, 2004 letter from the Commission. In the VIGP Decision, the Commission had calculated the shortfall in the winter of 2007/08 to be 116 MW, but it acknowledged that a 150 MW minimum acquisition provided an appropriate cushion for planning purposes. Events subsequent to the VIGP Decision confirmed that the gap is growing, not shrinking. Accordingly, BC Hydro established a minimum portfolio of 150 MW and a maximum portfolio size of 300 MW. BC Hydro argued that any portfolio beyond 300 MW needed to be confirmed in a larger resource planning exercise. At the same time, BC Hydro designed a process that would permit it to keep bids from smaller projects if no cost-effective project emerged that met the minimum portfolio size requirement.

BC Hydro also observed that as a result of the use of an absolute NPV selection criterion "…all other things being equal, the smaller portfolios, towards the smaller end of the allowable size range (150 MW) are favoured in the QEM" (Exhibit B-101, GSXCCC Supplemental IR 2.2.1). It is therefore no surprise that the smaller plant without duct-firing was selected by the QEM. This result is due in part to the removal of the Transmission Deferral Credit ("TDC") in response to the Commission's letter of January 23, 2004. The original QEM had included a TDC for capacity in excess of 150 MW. The removal of the TDC had the effect of disadvantaging larger projects (such as those using VIGP assets) relative to smaller projects, given the fact that the QEM focused on the least cost NPV.

With respect to the basis for comparing tenders, during cross-examination, Ms. Hemmingsen characterized various unit cost measures as being summary metrics that are incomplete in representing the values of various resources. She stated that:

> "…the standard evaluation methodology is cash-flow analysis and net present value cash-flow analysis. And that's what we do, and that's what we incorporated in the model. And once again, my understanding of the VIGP decision is that approach was endorsed, and there was some specific recommendations in the VIGP decision to proceed using that type of approach, albeit to simplify some of the elements of it. And that's what we attempted to do in the QEM model, and there's various trade-offs involved in making simplifications, but it goes back to our overall balance of, you know, focusing on a cost-effective outcome, making the model transparent and facilitating fairness and openness in the process…."
>
> (T8: 1656).

From a practical perspective, BC Hydro pointed out in Argument that the alternative Tier 1 outcome using a $/MW selection criterion would involve the same proponent and the same plant, with the only difference being the addition of duct-firing capability in the EPA. Furthermore, BC Hydro noted that:

> "[a] … critically important fact in analyzing these issues, and, under the circumstances, a fortuitous one, is that both of DPP's bids include duct firing capacity… The only difference between the two bids was that in one, the capacity was contracted to BC Hydro; in the other, it was left available to the merchant market…Because BC Hydro controls dispatch over the facility, the value of duct firing lies almost exclusively with BC Hydro…Thus, as DPP's testimony made clear, the additional output should be available on terms that are favourable to BC Hydro."
>
> (BC Hydro Argument, pp. 7, 8)

With respect to the Commission's authority to require, encourage, or otherwise comment on the desirability of including duct-firing in the DPP plant, BC Hydro argues that:

> "…the Commission cannot require DPP to sell the additional 28 *MW* to BC Hydro and should not try to do so. Under section 71 of the Act, the Commission may choose between two remedies if it believes action on its part is necessary to protect the public interest. First, it can disallow all or part of the EPA. Second, and alternatively, it can approve the EPA, but impose such noncontractual terms and conditions as are required to protect the public interest. What *the Commission cannot do is disallow* parts *of the EPA and substitute terms and conditions that it thinks might be more desirable in the contract…* BC Hydro acknowledges that the Commission could approve the EPA under section 71(3)(b) of the Act with conditions that would require BC Hydro to contract for the additional 28 *MW* of capacity from DPP before it is allowed to proceed with the EPA. But BC Hydro does not advocate that the Commission employ this authority. Rather, it believes that the EPA should be approved unconditionally and the decision of whether to buy the additional 28 *MW* of capacity from DPP should be left to BC Hydro."
>
> (BC Hydro Argument, p. 9)

In Argument, DPP confirmed "…the facility DPP will actually construct, includes such duct-firing capability (T10: 2210); but this added capacity is not under contract to BC Hydro and is not included within the Terms of the existing EPA". DPP also confirmed that "…the value of the duct firing capability of its plant is of little relative value to DPP". DPP also argued that the Commission could encourage BC Hydro to secure the additional 28 MWs of duct firing capacity under a separate EPA but that "…an explicit order requiring DPP to make the duct firing capability available to BC Hydro is unnecessary…[since this]…capacity will be inherently available simply because of the physical nature of the plant that will be constructed by DPP" (DPP Argument, pp. 23, 24).

View of Intervenors

No intervenors specifically challenged the minimum portfolio size established for a Tier 1 outcome. Rather, most of the evidence revolved around the comparison of Tier 1 outcomes with the alternative Tier 2 possibilities. Possible Tier 2 outcomes and their comparison with the Tier 1 and No Award alternatives are discussed in the section on cost-effectiveness below.

With respect to the DPP bid with duct-firing, most intervenors used this issue to call into question the entire QEM and to suggest that the Commission must reject the EPA as filed. However, none of the intervenors specifically argued in favour of the plant with duct-firing outcome. For example, GSXCCC et al. argued:

> "The EPA is not in the public interest, with or without the extra 28 MW being conveyed to BC Hydro. Accordingly, the Commission should disallow the whole of the EPA and should *not* attempt to exercise its authority in relation to the extra 28 MW of capacity."
>
> (GSXCCC et al. Argument, p. 14).

With respect to the general issue of using unit costs, Green Island argued that "…the only calculation of importance [in comparing bids] was the $/MW of capacity calculation" (Green Island Argument, p. 7). In contrast, the JIESC's evidence and Argument seemed to suggest that the more appropriate comparison is the unit cost of energy from the various alternatives.

Commission Panel Determination

The Commission Panel has accepted the 150 to 300 MW size limits used by BC Hydro in identifying possible Tier 1 outcomes in the CFT (Section 4.3.4). Within this large range of possible Tier 1 outcomes, however, the Commission Panel is not persuaded by BC Hydro that the final selection criterion for the winning Tier 1 outcome is a defensible one. The Commission's comments in the VIGP Decision and in its letter of January 23, 2004 were merely suggestions and contained no specific requirement to use the absolute NPV of portfolios as the final selection criterion. A simplified model need not be simplistic.

The use of an absolute NPV criterion is appropriate when projects and/or portfolios have equal capacity and/or energy benefits. Indeed, it should yield the same result as a unit cost test. A unit cost is defined simply as the Net Tender Cost NPV or Net Portfolio Cost NPV divided by the average annual capacity or energy provided by the portfolio. This is in contrast to a more accurate levelized cost calculation, which involves dividing the Net Tender Cost NPV or Net Portfolio Cost NPV by the discounted sum of annual capacity provided by the project or portfolio. Where projects provide constant annual capacity benefits, the simpler unit cost calculation will yield the same project ranking as a more accurate levelized cost calculation. In the case of a tender process, the levelized cost of bids can be compared to BC Hydro's avoided costs of energy or capacity.

In cases requiring comparison of projects or portfolios of different sizes, the Commission Panel believes a unit cost of capacity (or in some cases the more elaborate levelized cost of capacity) may provide a more useful basis for comparison. The use of a unit cost or levelized cost is not inconsistent with a simplified NPV model. All it involves is dividing the absolute NPV by the average annual capacity or, in the case of the levelized cost, the discounted sum of annual capacity.

The Commission Panel acknowledges that this problem may have partly been created by the Commission's suggestion, in its letter of January 23, 2004, that BC Hydro eliminate the proposed transmission deferral credit for portfolios above 150 MW. However, that change alone may not address the problem entirely. Given the lumpy nature of capacity additions and therefore deferral credits, it is likely that a unit cost comparison could still prove useful for comparing projects and portfolios of different sizes, even when a deferral credit is applied to them. This is particularly true in a simplified analysis where other bridging resources or system benefits may not be captured in the NPV comparison. The unit cost or levelized calculations can provide not only a useful basis for comparing individual projects or portfolios, but also comparing them with other system benchmarks.

The Commission Panel believes that in the case of a capacity call, the unit or levelized cost of capacity, rather than the unit or levelized cost of energy, is a more relevant basis of comparing alternatives. In calculating the unit or levelized cost of capacity, the Commission Panel accepts the application of a credit for any energy margin produced by a project to offset its fixed costs, where applicable. Given the lumpy nature of capacity needs and investments, the Commission Panel also notes that the use of a minimum capacity threshold (in this case 150 MW) may be appropriate in defining the desired product and that unit or levelized costs only become relevant when this minimum threshold is met.

These determinations aside, the Commission Panel is not persuaded that in the context of this application, it should set aside the Tier 1 outcome, namely the DPP plant without duct-firing. The public interest must consider the consequences of setting aside the results of a competitive tender process, both in terms of the potential costs (and risks) associated with another process, as well as possible impact on the credibility given to future calls. In this particular case, the public interest can also be reconciled with the fact that the two projects are not mutually exclusive. Duct-firing represents an incremental capacity addition to the winning bid. The reason that the plant with duct-firing appears preferable is that this incremental capacity comes at a very low cost. It does not actually affect the unit or levelized cost of the base project. Acquiring the capacity of the plant without duct-firing does not preclude acquiring the incremental duct-firing capacity in the future and indeed is a prerequisite to capturing that capacity. DPP was not required to tender a project with duct-firing and had it not, the current project would still have been the preferred outcome, even if a unit or levelized cost comparison had been used as the basis for selection among the Tier 1 projects. Also important to the Commission Panel are the facts that the winning plant will include duct-firing, although it may not yet be contracted by BC Hydro, and that duct-firing will likely have no value to any other entity than BC Hydro. For these reasons, the Commission Panel believes that it would not be in the public interest to reject the EPA, as filed, or to attach conditions for the addition of duct-firing prior to approval. However, the Commission Panel strongly urges BC Hydro to bring forward an EPA for the residual capacity on terms comparable to those suggested in DPP's non-winning bid.

12.0 UNSUCCESSFUL BIDS

A total of 23 bidders registered initially in the CFT. Of these, 14 submitted pre-qualification applications, which were assessed against the Mandatory Criteria. Three bidders were disqualified from further participation due to failure to meet the Mandatory Criteria. Eleven bidders with 22 discrete projects successfully pre-qualified for the CFT. Six of the pre-qualified bidders submitted Tenders covering a total of ten discrete projects. Two Tenders (covering three projects) were rejected for non-compliance with the CFT requirements. One failed to deliver tender security by the prescribed deadline and the other submitted conditions that were considered material (T8: 1596). Of the remaining Tenders, two involved VIGP projects (with and without duct-firing). Of the remaining two bidders, a proposed a 47 MW gas-fired peaker plant (with and without dual fuel) and another Green Island's proposed a 75 MW biomass plant.

All six projects were evaluated using the Net Tender Spreadsheet in the QEM. Only five Tier 1 portfolios were evaluated using the Portfolio Spreadsheet in the QEM. The two smaller projects totalling 122 MW were not included in any Tier 1 portfolios because they could not be combined with any projects to yield a viable Tier 1 portfolio, defined in the CFT as a portfolio with a total capacity of 150 to 300 MW. The Commission received the confidential QEM results for all six projects and five portfolios evaluated by BC Hydro. In response to Information Requests from BCUC Staff and an undertaking requested by Gold River, the Commission also received an evaluation using the QEM of the 122 MW portfolio that did not meet the minimum 150 MW size threshold established in the CFT process. This portfolio formed part of the Tier 2 outcome that BC Hydro considered in the cost-effectiveness analysis performed for senior management.

<u>The Calpine Tender</u>

One of the disqualified tenders was a co-generation expansion project in Campbell River put forward by Calpine. Calpine submitted a bid that sought a right to terminate in 2029 (instead of the required term ending in 2031) if Calpine could not extend its leasehold terms. BC Hydro considered this a conditional bid and declined to waive this material non-compliant requirement (T6: 1128).

In a letter of comment to the Commission dated January 6, 2005 (Exhibit E-123), Calpine confirmed its ability to bring on-line its Campbell River Cogeneragtion Expansion project within the timeframe established by the VICFT. Calpine also indicated that it would not object to the Commission directing BC

Hydro to file, confidentially with the Commission, Calpine's bid. In response to a request from Green Island during the hearing, BC Hydro indicated that because the bid was non-compliant, it did not look at it and it sent it back to Calpine and so could not provide the pricing information, even if directed (T15: 3029).

In its evidence and Argument, Green Island put forward several alternative Tier 2 portfolios all incorporating its biomass plant. In one portfolio, it included Calpine's cogeneration project. Green Island argued that if the Commission Panel established that the Campbell River project was disqualified due to unduly stringent Mandatory Criteria, the Commission Panel should consider this project for inclusion in an approved portfolio (Exhibit C9-10, p. 2). In response to a request from Green Island during the oral phase of the proceeding (T15: 3031), the Commission Panel left the record open for an extra 48 hours to accommodate a filing of the specified information from Calpine; however, nothing was forthcoming.

BC Hydro argued that changing the minimum term from 10 years to 25 years "…reflected the need to have a simple and straightforward basis for comparison of bids by requiring them all to be for the same term" (BC Hydro Argument, p. 27). While testifying on behalf of BC Hydro, Mr. Soulsby argued that most bidders would have opted for a longer term to accommodate financing requirements and he also noted that none of the registered bidders had raised questions about the change in term, which occurred after the pre-qualification stage (T6: 1216).

With respect to the specifics of the Calpine Tender, BC Hydro argued that:

> "…it is a false premise to assume that if BC Hydro had accepted the bid, Calpine would somehow have been included within a winning portfolio. The evidence is to the contrary. While it is true that the bid was rejected because it contained a material condition (as acknowledged by Calpine), it would have been rejected in any event. The Independent Reviewer makes this clear in its fourth report where it indicates that the tender security accompanying the Calpine bid was inadequate."
>
> (BC Hydro Argument, p. 36)

Commission Panel Determination

During the Pre-hearing Conference, the Commission Panel indicated that:

> "…in the absence of evidence from developers, it may not be persuaded that the CFT is not satisfactory evidence that Duke Point is the most cost-effective resource for Vancouver Island at this time."
>
> (T2: 312)

Calpine was given an opportunity to participate in this proceeding and to challenge the CFT process or outcome and present information or file evidence in this regard. Calpine did not avail itself of that opportunity. The Commission Panel accepts BC Hydro's evidence that Calpine's bid would have been disqualified in any event due to inadequate tender security. This requirement in the CFT was not disputed by intervenors. In these circumstances, the Commission Panel does not consider that further consideration of the Calpine bid is warranted or appropriate.

The Commission Panel accepts BC Hydro's evidence that Calpine's bid would have been disqualified in any event due to lack of adequate tender security. This requirement in the CFT was not disputed by intervenors. In these circumstances, the Commission Panel does not consider that further consideration of the Calpine bid is warranted or appropriate. The Commission Panel accepts BC Hydro's evidence that there were only five possible Tier 1 outcomes, as defined in the terms of the CFT, and re-affirms that the DPP plant was the preferred Tier 1 outcome.

13.0 NON-GENERATION RESOURCE ADDITIONS

The Commission's letter of January 23, 2004 stated that cost-effective CFT portfolios with dependable capacities as low as 115 MW should be accepted before considering resource additions other than on-Island generation (Exhibit B-1, Appendix F, p. 3). Two such resource additions attracted significant attention in these proceedings. The focus of one of the resource additions, the NorskeCanada Demand Management Proposal ("NCDMP"), was on capacity displacement. The focus of the second resource addition, the 230 kV Vancouver Island Transmission Reinforcement Project ("VITRP"), was on the timing of transmission capacity replacement.

13.1 NorskeCanada Demand Management Proposal

NorskeCanada filed a NCDMP dated September 2, 2004 (Exhibit C2-3). BCTC evaluated the NCDMP and, in December 2004, issued a summary report entitled "Evaluation of NorskeCanada's Demand Management Proposal Dated September 2, 2004" (Exhibit A-43, the "Summary Report"). Many intervenors registered their interest in relying on this report (NorskeCanada Exhibit C2-5; BCOAPO Exhibit C3-9; Green Island Exhibit C9-12; JIESC Exhibit C19-14; GSXCCC et al. Exhibit C20-26; Shadybrook Farm Exhibit C33-7; McLennan Exhibit C36-11). BC Hydro, citing CFT rules, had not engaged in any discussion with NorskeCanada regarding the NCDMP (Exhibit B-12, BCOAPO IR 1.13.3; T9: 1958-1959; T7: 1366).

13.1.1 <u>BCTC Evaluation of the NCDMP</u>

In the Summary Report, BCTC identified the following significant technical and contractual characteristics of the NCDMP:

- Between 30 MW and 210 MW of demand management and load shifting or curtailment was available;
- There were specific contractual provisions for the duration and frequency that the NCDMP could be called upon annually; and
- A trial program of the NCDMP could be implemented as early as NorskeCanada's maintenance outage period in 2005.

In transmission system planning, “N-1 criteria” means that the transmission system must not experience general system instability, uncontrolled separation, cascading outages, or voltage collapse for the loss of any single element in the transmission system (referred to as a “single contingency”), or if it has sufficiently high probability, any single event that takes multiple elements out of service. BCTC observed that the contractual duration and frequency provisions of the NCDMP detracted from its usefulness as a planning tool for satisfying the N-1 criteria (Exhibit A-43, Summary Report, p. 4). NorskeCanada’s testimony was that the NCDMP was its interpretation of the requirements of the system, and there were areas of flexibility that could be explored in discussions with BC Hydro (T11: 2455).

13.1.2 Transmission Planning and Resource Adequacy Criteria

BCTC references transmission planning standards and specifically the N-1 criteria in a footnote on page 2 of the Summary Report. The WECC is a council that was formed due to international concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization. Its mandate includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 western states in the United States. The WECC has developed and published criteria that apply to transmission planning (WECC Reliability Criteria, dated April 2004) that have been previously endorsed by the Commission. The BCTC reference identifies allowable system responses to Category B (single contingency) events (WECC Reliability Criteria, Table 1, p. 24). NorskeCanada observes that the footnote to Category B of Table 1 allows for planned or controlled interruptions to electrical supplies to radial customers or local network customers in response to a first contingency under certain circumstances (NorskeCanada Argument, p. 7). BCTC confirmed that shedding or curtailing load in response to a severe contingency would not necessarily be perceived as a violation of North American Electricity Reliability Council (“NERC”) and WECC planning criteria (T10: 2285). BCTC stated that such responses to severe contingencies have been considered for just about every critical region of the system (T10: 2287).

The WECC Reliability Criteria also addresses the evaluation of dependable capacity on page 56. According to the standard, an annual testing is required to verify the gross and net dependable capacity. The standard also states that each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its region.

The Commission Panel expects BC Hydro to review with stakeholders the detailed procedures and policies it has adopted to determine the dependable capacity of various types of gas-fired, coal-fired, cogeneration, hydroelectric, wind and biomass generating units. The Commission Panel suggests the ROR filing and process may provide an appropriate forum for such a review. BC Hydro should also consider whether project-specific procedures are necessary or appropriate for assigning dependable capacity values to the foregoing classifications of generating units for system planning purposes. This information is to be submitted prior to the next EPA application, or in conjunction with the next REAP, ROR, or IEP filing.

The Commission continues to endorse the WECC Reliability Criteria, and specifically the adoption of the N-1 planning criteria. Although the WECC Reliability Criteria recognize controlled load shedding as an appropriate response to single contingency events, the Commission Panel does not consider this an appropriate response in the context of long-term planning for the Vancouver Island transmission system except for radial loads.

13.1.3 Status of the NCDMP in the CFT

Several intervenors suggest that the NCDMP should be part of an optimal solution (BCOAPO Argument, p. 23; JIESC Argument, p. 10; NorskeCanada Argument, p. 2; Green Island Argument, p. 4). BC Hydro submits that NorskeCanada should have formally withdrawn from the CFT process to free itself to pursue discussions regarding the NCDMP with BC Hydro (BC Hydro Reply, pp. 20, 21).

In its letter of January 23, 2004, the Commission stated that with respect to the scope of the CFT, "Load Management (Demand-Side Management) and load curtailment projects are not eligible" (Exhibit B-1, Appendix F, p. 3). **In the presence of a cost-effective outcome to the CFT process, the Commission Panel finds that the NCDMP does not constitute a viable option to accomplish the objectives of the CFT.**

However, the Commission Panel does view the NCDMP as a valuable and useful tool outside the CFT process. Controlled load curtailment in response to multiple contingencies or as a short-term operational measure is preferable to the alternative of a cascading system disturbance with uncontrolled characteristics. **Therefore, the Commission Panel encourages BC Hydro to actively pursue discussions with NorskeCanada with the objective of beginning a trial of load curtailment during the maintenance outage period of 2005.**

13.2 Vancouver Island Transmission Reinforcement Project

BCTC is proposing to install two new 230 kV circuits between the Mainland and Vancouver Island, utilizing roughly the same corridor as the existing 1L17 and 1L18 138 kV circuits. The VITRP is still in the definition phase, with the first circuit scheduled to enter service as early as October 2008, and the second circuit at least ten years later. Each 230 kV circuit will have a normal rating of 600 MW. The Commission Panel determined that transmission alternatives were not to be considered within the scope of this proceeding, and for the purpose of this proceeding accepted that the 230 kV project is the preferred next transmission-based capacity addition to Vancouver Island (T2: 309). The Commission Panel also determined that because the timing of the VITRP project is relevant to the economics of the comparison of Tier 1, Tier 2, and the No Award alternatives, the timing of the VITRP was within the scope of this hearing (T2: 310).

13.2.1 Timing of the VITRP

The definition phase of the project is scheduled to last until all approvals are obtained and ends with the Earliest Construction Start ("ECS") milestone. Based on a CPCN application for the project in June 2005, the ECS milestone is October 2006 (Exhibit C6-2, BCUC IR 1.2.2, Gantt Chart dated December 16, 2004, Revision 9, p. 2). The Commission Panel notes a significant advancement in the CPCN application date from the April 2004 draft Project Plan (Exhibit C6-2, BCUC IR 1.3.3, Gantt Chart FastR0.mpp, dated December 16, 2004).

The Project Risk Log was examined in some detail in testimony (Exhibit C6-2, BCUC IR 1.3.3; T10: 2338-2387). BCTC's evidence was that the project has progressed considerably from its state as reflected in the April 2004 draft Project Plan, and some risks had been eliminated. Few, if any, issues pose greater risk to the project than had been identified in the April 2004 draft Project Plan, however, there are several unresolved risk elements that could delay the project. Among these are the uncertainties associated with the outcome of public and First Nations consultation, permitting processes, and access to specialized construction equipment. Public and First Nations consultation has started, with some indication of local public opposition to the project in proximity to the existing right-of-way through the Tsawwassen area (T10: 2376). BCTC has opted into the *B.C. Environmental Assessment Act* process (T10: 2369-2370). A portion of the VITRP consists of underwater cable in U.S. territory. This triggers the need for either a new U.S. Presidential Permit or modification of the existing Permit in place for 1L17 and 1L18. In addition, specific studies must be performed for both the Canadian Environmental Assessment Act and the U.S. *National Environmental Policy Act* (T10: 2369-2372), and there may be a further requirement for approvals under those acts resulting from the studies. If approvals are necessary, there was no specific timeline provided for their acquisition. Specialized cable-laying ships are required for installation of this cable, and there appear to be very few such ships (T10: 2382-2383). Accessing appropriate ships may be difficult if the project does not meet pre-arranged windows when the equipment has been booked.

BCTC has a reasonably high level of confidence that the 230 kV project can be implemented by October 2008 but cannot guarantee this outcome (T10: 2288; BCTC Argument, p. 2). BC Hydro argues that the October 2008 implementation date is a "best efforts" target, and that prudent planning dictates that an implementation date of April 2009, or later, is appropriate (BC Hydro Argument, p. 10). This argument is also made by DPP (DPP Argument, p. 16).

The Commission Panel finds that notwithstanding the progress made on managing the risks identified in the April 2004 Project Risk Log, significant risks remain in implementing the VITRP in time to meet the 2008-2009 winter peak. Therefore, the Commission Panel finds it is prudent to base any planning and economic analysis on an in-service date for the VITRP of March 2009, or later.

Nevertheless, the Commission Panel expects BCTC to pursue the October 2008 implementation date for the VITRP and anticipates a CPCN application in June 2005 that compares the VITRP against other transmission reinforcements. The application should contain a detailed permitting and construction schedule (with critical path milestones identified monthly) and a description of a construction management process that establishes and monitors monthly milestones throughout the project construction phase.

14.0 THE COST-EFFECTIVENESS EVALUATION

14.1 Introduction

Following the selection of the Tier 1 outcome, BC Hydro conducted a cost-effectiveness evaluation comparing the Tier 1 outcome to the Tier 2 and No Award alternatives. The cost-effectiveness evaluation was conducted in accordance with Section 17 of the CFT (i.e., the privative clause), which was amended in response to the January 23, 2004 letter from the Commission. The privative clause permitted BC Hydro, at its discretion, to determine if the Tier 1 result was cost-effective relative to the Tier 2 and no CFT award alternatives. Tier 2 is the portfolio that arises from the exercise of Clause 17.3 of the CFT whereby BC Hydro could select tenders aggregating less than 150 MW of bid capacity if they had a lower Net Tender Cost per MW, adjusted for gas transportation costs and network upgrade cost. For the purposes of the cost-effectiveness evaluation, BC Hydro defined the Tier 2 portfolio as the two projects totalling 122 MW. The No Award option assumes that BC Hydro exercises the privative clause and cancels the entire CFT.

In addition to the direct costs of each portfolio, in the cost-effectiveness evaluation BC Hydro also considered costs associated with any backfill capacity and energy required to equalize the three portfolios, along with other benefits such as avoided losses and possible deferral of the second 230 kV cable to the Island currently planned in 2020. The cost and value of on-Island generation was derived from the QEM results. Other information used in the analysis included BC Hydro's estimates for the costs of the second 230 kV circuit, the cost of Mainland generation, the magnitude and value of any avoided losses as a result of on-Island generation, the cost of temporary generation (obtained from a quote provided by GE Canada), and the cost of NorskeCanada Demand Management (obtained from the proposal filed by NorskeCanada on September 2, 2004 in response to BCTC's Capital Plan).

14.2 Intent and Quality of the Cost-Effectiveness Evaluation

In the Pre-hearing Conference, the Commission Panel identified the cost-effectiveness evaluation as a key issue for this proceeding (T2: 313-314). During the oral hearing and in Argument, many intervenors placed considerable importance on the cost-effectiveness evaluation and challenged many of its assumptions and results.

The quality of the cost-effectiveness evaluation was called into question at several points in the hearing. For example, in responding to an Information Request from GSXCCC et al., BC Hydro discovered a calculation error (arising from a misplaced cell reference) under the High Gas/Low Electricity scenario which resulted in the under-estimation of Tier 1 cost by approximately $45 million (Exhibit B-12, GSXCCC et al. IR 1.25.3). The change increased the savings of the Tier 2 alternative from $32 million to $83 million and for the No Award alternative from $70 million to $123 million, relative to the Tier 1 alternative.

Throughout the hearing, BC Hydro frequently characterized the cost-effectiveness evaluation as simply a high-level check for senior management and that it was developed in only four days (T6: 1076). From the beginning, BC Hydro maintained that the cost-effectiveness evaluation should only become a key part of this hearing if it had been used to endorse a project, or sign an EPA with somebody other than the proponent that came out of the CFT process (T1: 32-33). In Argument, BC Hydro argues that Section 17.3 of the CFT was introduced after the process was initiated and that it grants BC Hydro the right but not the obligation to award one or more contracts totalling less than 150 MW where senior management concludes, in their discretion, that the so-called Tier 1 outcome is not cost-effective (BC Hydro Argument, p. 35).

In its Reply, DDP similarly characterizes the cost-effectiveness evaluation as "…simply additional 'due diligence' by senior management, to obtain an added measure of 'comfort' before committing to an EPA and bringing forward the CFT winning bidder as representative of the most cost-effective option to meet the capacity deficiency on Vancouver Island" (DPP Argument, pp. 12, 13).

Commission Panel Determination

The Commission Panel agrees with BC Hydro that the privative clause gives it the right but not the obligation to award one or more contracts totalling less than 150 MW where senior management concludes the so-called Tier 1 outcome is not cost-effective. However, the Commission Panel does not understand how senior management could reasonably have exercised that discretion without some sort of cost-effectiveness evaluation of the type filed in these proceedings. Given the privative clause, BC Hydro should have contemplated the need for a comparison of the Tier 1, Tier 2 and No Award alternatives at the end of the process as a necessary prerequisite for exercising or not exercising its discretion in accepting the Tier 1 outcome.

In addition to a general expectation that BC Hydro will review the quality of its analyses prior to future filings, the Commission Panel also expects that BC Hydro will present information in a more consistent format in its filings. For example, some assumptions and results were presented using fiscal years while others were provided for calendar years. In addition, BC Hydro utilized many different base years for presenting results during the proceeding. This created unnecessary confusion and effort for the Commission and intervenors reviewing and comparing the various filings.

14.3 Definition of Tier 2

In order to conduct the cost-effectiveness evaluation, BC Hydro needed to identify a Tier 2 outcome. According to the privative clause, BC Hydro could select tenders aggregating less than 150 MW of bid capacity if they had a lower Net Tender Cost per MW, adjusted for gas transportation costs and network upgrade cost. BC Hydro defined the Tier 2 portfolio as two projects totalling 122 MW. Through the course of the hearing, it became clear that these two projects were the Green Island Biomass Plant, totalling 75 MW, and EPCOR’s proposed Ladysmith peaking plant with 47 MW of capacity. In Argument, BC Hydro stated that its approach to defining Tier 2 was “…predicated on the assumption that proponents that could not or did not bid their projects into the CFT process cannot be reliably included in Tier 2” (BC Hydro Argument, p. 34). BC Hydro argued that alternative portfolios assembled by Green Island and others were really only hypothetical portfolios consisting of bids that were rejected for not meeting mandatory criteria (e.g. Calpine) or that did not take the form of generation on Vancouver Island, and therefore did not deserve serious consideration.

In its evidence, Green Island identified the second Tier 2 project as an EPCOR project located in Ladysmith and put forward four alternative Tier 2 portfolios also incorporating this project:

- Green Island’s Gold River Power Project (75 MW) + Peaker Plant (47 MW) + Norkse Demand Management Program (130 MW);
- Green Island’s Gold River Project (75 MW) + Peaker Plant (47 MW);
- Green Island’s Gold River Project (75 MW) + Two Peaker Plants (94 MW); and
- Green Island’s Gold River Project (75 MW) + Peaker Plant (47 MW) + Calpine’s Cogen Expansion Project (48MW).

In reviewing the confidential cost information filed by BC Hydro, Commission staff also questioned BC Hydro regarding the definition of Tier 2. Specifically, staff asked BC Hydro to undertake to provide separate unit costs (i.e., Net Tender Cost / MW of bid capacity) for the 75 MW Green Island Project and the 47 MW peaking plant, after adjusting for firm gas transportation and network upgrade costs associated with each project. Confidential Exhibit B-96 confirms that on a $/MW basis, adjusting for network upgrades and firm gas tolls, the cost of Green Island's Gold River project alone is lower than the cost of the peaking plant, and by extension the cost of the two projects combined.

Commission Panel Determination

At T3: 453, the Chair confirmed that for the purposes of the cost-effectiveness evaluation, the Tier 2 portfolio is defined as the two projects totalling 122 megawatts, as outlined in Appendix J of the CFT. As noted in other parts of this Decision, the Panel sees no need for further consideration of Calpine's bid and a second hypothetical peaking plant that was not bid into the CFT. The only difference between Green Island's Portfolio 2A and 2B is the addition of NorskeCanada's Demand Management Program. BC Hydro's Tier 2 definition is essentially the same as Green Island's portfolio 2A with the addition of temporary generators to meet any remaining capacity deficits beyond 2008 until the 230 kV line is in service. The treatment of backfill capacity and energy in the evaluation is discussed further below.

The Commission Panel observes that BC Hydro's actual definition of Tier 2 appears to be inconsistent with its description of the Tier 2 portfolio as the "tenders aggregating to less than 150 MW of bid capacity on the basis of the lowest-cost Net Tender Cost per MW, adjusted for gas transportation costs and network upgrade costs" (Exhibit B-1, p. 13). According to Confidential Exhibit B-96, the Gold River project alone (totalling 75 MW) may have been lower cost on a $/MW basis, than the Gold River project and peaking plant combined. However, based on all of the evidence, the Commission Panel does not believe this fact is material with respect to the comparison of Tier 1 and Tier 2 given the additional backfill capacity that would be required in the absence of the peaking plant.

14.4 Capacity and Energy Backfill

In order to compare the three possible CFT outcomes, BC Hydro equalized the energy and capacity added to the system in each portfolio. To meet reliability criteria on Vancouver Island, BC Hydro added additional capacity resources to each portfolio to cover any deficiency between forecast demand and on-Island generating capacity between the de-rating of the HVDC Line and an expected in-service date of the next 230 kV cable in April 2009 (F2010). In all portfolios, any deficit between demand and on-Island generation is first met with NorskeCanada's Demand Management Proposal, based on costs in NorskeCanada's proposal, and then, if necessary, temporary TM2500 generators (i.e., distillate-fired mobile generators). The costs of the temporary generation were developed based on information provided by GE Canada. These contingency measures were selected based on their relative reliability and cost certainty characteristics compared to other potential contingency supply options identified by BC Hydro (Exhibit B-9, BCUC IR 1.40.2).

No attempt was made to equalize energy benefits of the portfolios prior to 2009. However, BC Hydro argues that in 2009 (F2010) the provincial system starts to become energy critical (Exhibit B-9, BCUC IR 1.37.1). BC Hydro therefore added additional energy to the Tier 2 and No Award portfolios beginning in 2009 to equalize the energy benefits provided in these portfolios with those in the Tier 1 outcome. Although the magnitude of the system energy deficit does not exceed 1,800 GW.h (the average expected output of the DPP plant) until F2013, BC Hydro used a simplifying assumption and assumed a constant backfill of 600 GW.h per year in the Tier 2 alternative, and 1,800 GW.h per year in the No Award alternative. In both Tier 2 and No Award, BC Hydro assumed the energy backfill was to come from new Mainland generation, primarily from future IPP calls. In the base case, BC Hydro assumed a backfill cost equal to 100 percent of the Tier 1 project on Vancouver Island (i.e., the DPP plant), excluding firm gas tolls, since those are unique to gas-fired generation located on the Island. BC Hydro also conducted a sensitivity analysis assuming the cost of Mainland generation was 90 percent of the cost used in the base case.

The cost of Mainland generation reflects the levelized capital and operating costs of the DPP plant (excluding firm gas tolls) under expected dispatch. This produced a cost of $62/MW.h ($2004) (Confidential Exhibit B-10, BCUC IR 1.41.1). Recent calls have resulted in projects with costs in the order of $55/MWh, but BC Hydro noted that these were projects with limited dependable capacity (Confidential Exhibit B-10, BCUC IR 1.15.3). BC Hydro argued that the $62/MW.h was a more realistic estimate of the cost of firm energy comparable to that provided by the DPP plant. The 90 percent Mainland generation cost scenario evaluated by BC Hydro in the sensitivity analysis is closer to the $55/MW.h for non-firm energy obtained in recent calls. In all portfolios, the value of Mainland generation was estimated using the same two electricity price forecasts used to estimate the value of energy from CFT projects in the QEM (i.e., the average of EIA-Full and EIA-Partial electricity forecasts).

During the hearing, many intervenors questioned the cost and value assumptions for Mainland generation. For example, the JIESC argued that:

> "…what BC Hydro did in the Cost Effectiveness Analysis was to purport to backfill the energy supply but failed to do so in an appropriate or reasonable way and in a way that is comparable to the net energy margin applied to the DPP EPA. What BC Hydro should have done is credit the "No Award" option with a similar margin to that credited to the Tier 1 Option, $172 million, instead it used zero."
>
> (JIESC Argument, p. 34)

The JIESC prepared comparisons of Tier 1 with the Tier 2 and No Award outcomes with an additional credit of $115 million and $172 million respectively, for the energy margin on backfill. In Reply, BC Hydro argued that the JIESC's "recalculation of the energy margin is flawed because it credits Tier 2 and the No Award with energy margins already taken into account in the breakdown of Appendix J, Attachment A presented in response to BCUC IR 2.46.6" and "[t]o add in a separate Energy Margin is double counting" (BC Hydro Reply, p. 27).

In its confidential response to BCUC IR 2.73.1, BC Hydro provided a comparison of the unit cost of Tier 1 vs. Tier 2 (i.e., the NPV of each portfolio divided by the average annual capacity provided by the portfolio) excluding any backfill for Mainland energy. This comparison confirmed that Tier 1 was less costly on a unit cost basis than Tier 2, even without considering the backfill energy used to equalize system energy benefits. In its response, BC Hydro also provided an alternative analysis of Tier 1, Tier 2 and No Award alternatives that did not attempt to equalize the system energy provided by each portfolio in F2010 and beyond, but did equalize the capacity provided to the system in these years. BC Hydro considered two alternative forms of back-fill capacity: 1) a 480 MW hydroelectric capacity project in the interior of B.C.; and 2) 47MW peaking plants based on actual pricing obtained from the CFT (excluding firm gas transportation tolls). The analysis showed that Tier 1 had a lower NPV than the Tier 2 and No Award alternatives using peaking plants for backfill capacity, with the magnitude of savings increasing as the in-service date of the next AC Cable is delayed. Tier 1 was also less costly than the Tier 2 alternative using the hydro project for backfill capacity. Tier 1 was more costly than the No Award scenario under the hydro backfill option. However, this analysis did not include any costs associated with additional interior to Lower Mainland transmission.

Commission Panel Determination

The Commission Panel agrees in principle with equalizing the capacity and energy benefits to aid comparison among the three outcomes. Much of the controversy surrounding the backfill energy seems to have arisen from the different approaches used in the QEM and cost-effectiveness evaluation. This confusion is unfortunate and could have been avoided if BC Hydro had used a more consistent approach in the QEM and cost-effectiveness evaluation.

The Commission Panel agrees with BC Hydro that the JIESC calculation represents potential double counting. This is because the "energy margin" for Tier 1 and Tier 2 that is calculated in the QEM and referred to at various points during the hearing, represents the difference between the operating costs of on-Island generation (i.e., excluding any capital costs) and the market value of energy. In both Tier 1 and Tier 2, the energy margin is a positive value that is then credited against the fixed costs of the portfolios. In the case of backfill energy, BC Hydro uses a single levelized cost of Mainland energy, which includes both capital and operating costs.

With respect to the energy backfill, there are two principle issues of concern to the Commission Panel. The first is the actual amount of backfill energy applied to the alternative portfolios. The second is the cost of Mainland energy assumed by BC Hydro.

With respect to the first issue, the Commission Panel notes that BC Hydro used system energy requirements to justify the backfill. However, according to BCUC IR 1.15.3, BC Hydro used the actual expected generation from the DPP plant for F2010 and beyond in calculating the cost of backfill energy. According to BCUC IR 1.37.3, the magnitude of the system energy deficit beginning in 2009 is only 407 GW.h, which is more than 1,000 GW.h less than the expected production from the DPP plant. System energy needs do not exceed expected DPP production from the DPP plant until 2012 (F2013). The Commission Panel appreciates BC Hydro's desire to simplify the analysis, but using the actual system energy deficit between 2009 and 2012 would lower the cost of backfill energy in the No Award outcome by nearly $40 million and the value of Mainland energy would be nearly $26 million lower (under BC Hydro's levelized cost and value assumptions), a net reduction of about $13 million in the cost of the No Award outcome. This change would have a much smaller effect on the higher-cost Tier 2 outcome because the magnitude of backfill energy included the Tier 2 is already much smaller than the No Award scenario.

In terms of the cost of Mainland generation, the Commission Panel agrees with BC Hydro that the cost of firm energy required by the system is likely higher than the value of electricity estimated using the average of the EIA-Full and EIA-Partial forecasts. The Commission Panel is not convinced the 25 percent premium implicit in BC Hydro's analysis is entirely justified, particularly given that BC Hydro is likely to rely on a mix of firm and non-firm purchases in order to manage electricity costs and no evidence was provided regarding the timing or cost of future system capacity requirements. However, the Commission Panel estimates that a premium of 18 percent or more is all that is required to make the cost of the Tier 1 portfolio lower than the No Award alternative. The Commission Panel notes that the alternative capacity analysis also confirmed the lower cost of Tier 1 using Mainland peaking plants for backfill. Under the hydro capacity backfill, Tier 1 was still less costly than Tier 2, but not the No Award alternative. However, the Commission Panel acknowledges the uncertainty with respect to the likely source of capacity, and the additional transmission costs associated with capacity in the interior (which is required to deliver the additional hydro capacity), which were not included in the analysis. The Commission Panel accepts that there is some value to the system from capacity beyond 2009 and is comfortable that the value is likely in excess of this minimum threshold to make the expected cost of Tier 1 the lowest of the three outcomes under BC Hydro's base case assumptions.

14.5 Expected Cost of Tier 1 vs. Tier 2 vs. No Award

As outlined in Exhibit B-1, Appendix J, BC Hydro estimated the expected cost of the Tier 1, Tier 2 and No Award under a set of base case assumptions. The base case assumed:

- CFT costs and electricity prices as calculated in the QEM;
- Cost of NorskeCanda Demand Management as outlined in NorskeCanada's Demand Management Proposal;
- Cost of Temporary Generators obtained from a quote provided by GE Canada;
- April 2009 (F2010) in-service date for 230 kV cable;
- 261 MW peak load deficit in F2008; and
- A cost of comparable Mainland generation of \$62/MWh (\$2003) (essentially the DPP plant without firm gas tolls).

The net present value costs of each outcome for the base case are summarized below. These are derived from more detailed results provided in BC Hydro's Confidential Response to BCUC IR 1.14.3. The table summarizes the incremental cost of Tier 2 and No Award relative to the Tier 1 outcome. In addition, the table illustrates the relative cost of each portfolio excluding the credit for sale or salvage of VIGP assets.

The Tier 1 outcome represents a NPV savings of $51 million relative to the No Award scenario and a savings of $86 million relative to the Tier 2 outcome, including the incremental cashflows associated with the transfer/salvage of the VIGP assets.

Expected Cost ($2003) of Tier 1 vs. Tier 2 vs. No Award Outcomes
(Aggregated Results from Confidential Response to BCUC 1.14.3)

	Tier 1	Tier 2	No Award
Bridging Supply	5	45	105
CFT (before VIGP Credit)	1,187	481	0
VIGP Credit	-43	-12	-12
System Impacts			
AC Cable Phase 1	122	122	122
Avoided Losses	-41	-14	0
AC 2nd Cable Deferral Credit	-22	-11	0
Cost of Mainland Generation	0	667	997
Value of Energy (Non-Firm)	-849	-833	-802
Total Cashflows	359	445	410
Premium (savings) Relative to Tier 1	0	86	51
Total Cashflows Excluding VIGP	402	457	422
Premium (savings) Relative to Tier 1	0	55	20

In Argument, BC Hydro also points out that, under the electricity price forecasts it used, the above analysis assumes that Duke Point plant recovers only 62.5 percent of its capital cost (BC Hydro Argument, p. 38).

In its response to BCUC IR 2.73.1 (Confidential Exhibit B-15), BC Hydro also provided an alternative comparison of the Tier 1, Tier 2 and No Award alternatives that did not attempt to equalize the system energy provided by each portfolio in F2010 and beyond, but did equalize the capacity provided to the system in these years. BC Hydro considered two alternative forms of back-fill capacity. As discussed in the previous section, this analysis did not differ directionally from the results shown above.

The JIESC and NorskeCanada argue that Tier 1 is clearly less cost-effective than No Award. Both suggest that the NorskeCanada Demand Management proposal, coupled with other unspecified resources, could offer a lower cost solution. These conclusions are reached without the full benefit of the confidential numbers filed with the Commission, and in both cases the proponents of these analyses made assumptions that the Commission Panel has determined are not appropriate. For example, the JIESC analysis applies an additional energy margin credit to the No Award outcome. The Commission Panel agrees with the BC Hydro that this represents potential double counting and attributes no value to system capacity beyond 2010.

Green Island and Gold River argue that Tier 2 is the most cost-effective resource. In response to Information Requests from BCUC Staff and an undertaking requested by Gold River, the Commission also received a confidential comparative evaluation of the 122 MW portfolio that did not meet the minimum 150 MW size threshold established in the CFT process. This portfolio formed part of the Tier 2 outcome that BC Hydro considered in the cost-effectiveness analysis performed for senior management. Green Island also conducted its own analysis of Tier 2 vs. Tier 1 alternatives. Neither the response to the Gold River undertaking nor the Green Island analysis includes sufficient backfill capacity on Vancouver Island to allow direct comparison with the above results.

In Argument, BC Hydro suggests the alternative portfolios put forward by Green Island fail to incorporate two important elements:

> "First, none of the portfolios contained in GIE's evidence provide enough capacity to meet the forecast capacity shortfall. The highest capacity its portfolio provides is Portfolio 2A, which offers 252 MW for two years, which is not sufficient to meet the forecast capacity shortfall in F2008 (the other three proposed portfolios have capacity of 122 MW, 169 MW and 170 MW, respectively). Second, it is inappropriate to compare the QEM-generated NPV of portfolios that have different capacity in the context of cost-effectiveness analysis. In that analysis, the additional capacity the 252 MW Tier 1 portfolio provides over the 122 MW Tier 2 portfolio has value not only in assisting BC Hydro in meeting the load deficit, but also has capacity value to the Island and to the system as a whole. BC Hydro submits that system benefits provided by Tier 1 can be properly evaluated via equalization of energy and capacity (Appendix J of the CFI Report), or capacity only (BCUC IR 2.73.1), for the duration of the Term."
>
> (BC Hydro Argument, pp. 38, 39)

CEC challenged the application of a credit for the sale or salvage of VIGP assets until determination of the disposition of those assets.

Most other intervenors simply challenged the specific assumptions selected for the base case. For example, many intervenors suggested that the magnitude of the supply deficit assumed for Vancouver Island was too high and also that BC Hydro should have used the earliest in-service date for the 230 kV cable.

Commission Panel Determination

The Commission Panel accepts the need to establish a defensible base case for the purposes of conducting the cost-effectiveness evaluation. In establishing the base case, it is not appropriate to use either the most favourable or the most unfavourable assumptions. Rather, the analysis must reflect a reasonable expected case. Risks can then be assessed with sensitivity analyses around the base case.

In these circumstances, the Commission Panel believes that the use of a F2010 in-service date is a reasonable assumption for the base case given an earliest in-service date of F2009 and the uncertainty associated with meeting the earliest in-service date. The evidence in the proceeding suggests that the supply deficit in F2008 is more likely to be 280 MW rather than the 262 MW originally assumed in the CFT. However, the difference relative to the original base case is not significant and, as noted in the sensitivity analysis below, merely serves to reinforce the conclusions in this analysis.

The expected cost estimates for temporary generation filed confidentially with the Commission are reasonable, particularly given the uncertainty in these costs (Confidential Exhibits B-10, BCUC IR 1.15.5; B-93; B-94). The costs associated with the NorskeCanada Demand Management option are consistent with the evidence filed by NorskeCanada, although no formal agreement has actually been reached between NorskeCanada and BC Hydro with respect to these costs. The CFT costs reflect the costs in the relevant tenders and the other adjustment accepted by the Commission Panel in the QEM. The value of electricity reflects the average of the two electricity price forecasts used in the QEM and accepted by the Commission Panel. The cost of Mainland generation used for backfill reflects the comparable cost of a new combined-cycle gas turbine on the Mainland, without gas tolls. This cost is not out of line with recent energy calls, particularly considering those calls provided limited capacity, which will also be required by the system beyond 2010.

The Commission Panel accepts there is some question regarding the appropriate treatment of the sale/salvage value of VIGP assets in the cost-effectiveness evaluation, but notes that eliminating this credit does not materially alter the ranking of the three outcomes.

14.6 Quantitative Sensitivity Analysis

BC Hydro performed a quantitative sensitivity analysis to test the robustness of the cost-effectiveness evaluation (Exhibit B-1, Appendix J). Specifically, BC Hydro examined the impact of the following uncertainties: 1) the timing of the in-service of the 230 kV transmission circuit; 2) the forecasted load deficit on Vancouver Island; 3) the gas/electricity price forecast; and 4) the cost of Mainland generation. No sensitivity analysis was conducted for gas tolls, one of the other main uncertainties identified by intervenors in the hearing (BCOAPO IR 1.20.5a).

With respect to the timing of the next 230 kV cable, BC Hydro evaluated the effect of in-service dates from F2009 (i.e., October 2008) to F2014. The base case analysis used an earliest in-service date of F2010 (i.e., March 2009). With respect to the load forecast, BC Hydro evaluated a high (350 MW) and low (150 MW) scenarios, in addition to the 261 MW capacity deficit assumed in the base case analysis for F2008. For electricity and generation prices, BC Hydro considered two alternatives to the base case scenario, which assumed Mainland generation costs are essentially the same as the DPP plant, excluding gas tolls (referred to by BC Hydro as the “Vancouver Island 250 MW combined-cycle gas turbine” or Vancouver Island 250 MW combined-cycle gas turbine Mainland price scenario). In one sensitivity analysis, BC Hydro assumed Mainland generation costs are 10 percent lower than the base case assumption. In another scenario, which BC Hydro characterized as an extreme stress test, it assumed the same plant as for Mainland generation as in the base case scenario, but used a high gas price forecast and low electricity price forecast.

A summary of the results of various sensitivity analyses relative to the base case is provided below. In general, the cost-effectiveness of the Tier 1 alternative declines if the size of the deficit on Vancouver Island is lower, the in-service date of the 230 kV cable is earlier, and the costs of Mainland generation are lower. However, the cost-effectiveness of the Tier 1 alternative increases rapidly under equally likely assumptions that the assumed size of the deficit on Vancouver Island is higher, the in-service date of the 230 kV cable is later, and the costs of Mainland generation are higher.

Summary of Quantitative Sensitivity Analyses
(Premium (savings) Relative to Tier 1)
(from Exhibit B-1, Appendix J, unless otherwise noted)

	Tier 1	Tier 2	No Award
Base Case NPV (BCUC 1.14.3)	0	86	51
F2009 AC Cable In-Service (BCUC 2.46.4)	0	64	15
F2011 AC Cable In-Service	0	106	90
90% Mainland Generation Cost	0	21	(47)
High Gas / Low Electricity (GSXCCC 1.25.3)	0	(50)	(87)
150 MW Load Deficit	0	53	2
350 MW Load Deficit	0	116	87

Note: All results reflect incremental impact of changes in individual assumptions relative to base case.

In Confidential Exhibit B-99, BC Hydro filed updated estimates of the cost-effectiveness analysis using the December 2004 Load Forecast, which suggested a capacity deficit of 280 MW in F2008, compared with the 261 MW deficit assumed in the Appendix J of Exhibit B-1. According to this supplemental analysis, the premium of Tier 2 over Tier 1 would increase to $ 91 million, while the premium for the No Award alternative would increase to $61 million.

BC Hydro argues that the sensitivity analysis confirmed the robustness of the Tier 1 outcome. Likewise, DPP argues “The evidence clearly confirms that the results of the CFT were tested in a variety of ways as part of the cost-effectiveness analysis; and were sustained as being reasonable across a broad variety of sensitivities” (DPP Reply, p. 13).

Intervenors consistently argue that more weight should be placed on those scenarios in which the Tier 1 outcome was less cost-effective than the Tier 2 or No Award outcomes. None seems to place much weight on any of the scenarios that would favour the Tier 1 outcome. Given the confidential nature of the detailed results, none of the intervenors could effectively conduct alternative sensitivity analyses for the full range of input assumptions.

Commission Panel Determination

The Commission Panel agrees with BC Hydro that the Tier 1 outcome is robust under the full range of uncertainties. The Commission Panel does not accept that the preferred solution must be the least costly solution under every possible scenario. The Panel has accepted the expected case put forward by BC Hydro and notes that there is an equal, if not higher probability, that events could unfold in ways that favour Tier 1 even more than suggested in the expected value analysis. In particular, the Commission Panel believes that given permitting uncertainties alone, there is an equal, if not higher probability that the in-service date of the 230 kV line could be delayed beyond F2010. There is also evidence that the magnitude of the supply deficit will likely be higher than the base case amount assumed by BC Hydro (280 MW vs. 261 MW), which further increases the cost-effectiveness of Tier 1 relative to the Tier 2 and No Award scenarios. The Commission Panel also accepts that the price forecasts used in the QEM and by extension the cost-effectiveness evaluation are conservative in that they put an equal probability on the partial recovery scenario. The Commission Panel agrees with BC Hydro that the High Gas/Low Electricity Price scenario has a very low probability relative to other potential outcomes.

14.7 Qualitative Considerations

There were other differences between the Tier 1, Tier 2 and No Award portfolios that were not addressed in the quantitative cost-effectiveness evaluation conducted by BC Hydro. BC Hydro identified several qualitative considerations that it felt were most relevant to the comparison of the three outcomes (Exhibit B-1, Appendix J). These included reliability, permitting risk, cost certainty, and competitive tendering.

In BCUC IR 1.15.1, BC Hydro points out that it did not include a consistent standard for certainty and reliability (Exhibit B-9). For example, the No Award scenario incorporates a lower standard of reliability in terms of availability and timing, and less cost certainty. The Tier 2 and, especially the No Award scenarios rely more on temporary generators than the Tier 1 alternative. BC Hydro argues that there may be significant permitting risks associated with such generators (e.g. operating restrictions and in-service length). BC Hydro notes that the cost certainty related to the temporary generators and demand management proposal are preliminary and not as firm or legally binding as the CFT bids. Finally, BC Hydro notes that the Tier 1 portfolio is the outcome of a competitive tendering and selection process.

In Argument, DPP characterized the bridging measures in the Tier 2 and No Award alternatives as “band aid” solutions and argued that “the overwhelming evidence in these proceedings confirms that such "band-aid" solutions are not adequate or appropriate measures to meet the forecast capacity deficiency” (DPP Argument, p. 3).

Many intervenors downplayed these qualitative considerations and none provided evidence that refuted them.

Commission Panel Determination

The Commission Panel places considerable importance on maintaining reliable service to the residents of Vancouver Island. The Commission Panel accepts BC Hydro’s arguments that the Tier 2 and No Award scenarios have lower reliability and less cost certainty than the winning Tier 1 outcome. The Commission Panel notes that under the base case scenario considered by BC Hydro, the Tier 1 outcome is already more cost-effective than the Tier 2 or No Award alternatives, even without taking into consideration the additional reliability and cost certainty provided by Tier 1. However, the Commission Panel finds that these qualitative benefits help to reinforce this conclusion and more than offset much smaller uncertainties in the cost-effectiveness of Tier 1.

14.8 Planning Timeframe

Many intervenors attempted to characterize the CFT result as an inappropriately long-term solution to a short-term problem. For example, in Argument, BCOAPO characterizes the CFT as “…a large square peg, that BC Hydro is seeking to insert into the round hole of Vancouver Island’s electrical capacity requirements” (p. 2). Specifically, BCOAPO suggest that the DPP plant is a long-term solution for a short-term problem of a deficiency between the zero-rating of part of the transmission system linking the island to the Mainland and the planned addition of a new 230 kV cable. After the installation of the new 230 kV cable, the plant would be redundant. The JIESC similarly characterizes the EPA as a very expensive long-term solution to a short-term problem (JIESC Argument, p. 2). CEC suggests BC Hydro has inappropriately blended a short-term need for on-Island capacity and a long-term need for system generation.

In Reply, BC Hydro refers to the evidence of Ms. Van Ruyven and Mr. Mansour that "…on-Island generation would provide significant reliability and capacity benefits leading to a more reliable system even after the transmission line is built" (BC Hydro Reply, pp. 21, 22). In Ms. Van Ruyven's Direct Testimony she also notes that the proposed solution is consistent with BC Hydro's long-run objectives of delivering reliable cost-effective supply (Exhibit B-35, p. 3).

Similarly, DPP argues:

> "The CFT was looking for a product which would provide part of the long-term solution to Vancouver Island's capacity requirements. To suggest that the DPP plant was only intended to serve a short-term, bridging requirement is simply not correct…DPP would also observe that an internal inconsistency exists in advocating a position which seeks to characterize the pending capacity situation on Vancouver Island as only "short-term", while at the same time supporting any generation option. Unless DPP is woefully misinformed, any generation option involves long-life assets, which would have long-term implications. Furthermore, to assert that the CFT was only intended to address a short-term issue flies in the face of the Commission's determination, made in the context of the VIGP Decision, that the appropriate next resource addition should be "on-Island" generation."
>
> (DPP Reply, p. 2)

Commission Panel Determination

The Commission Panel accepts BC Hydro's and DPP's submissions that Vancouver Island has a long-term supply problem requiring both generation and transmission solutions. The Commission Panel accepts the conclusion of the VIGP Decision that the next logical resource addition is on-Island generation. Although the CFT was driven initially by a near-term capacity deficit on the Island, the longer-term benefits to the Island and system were considered in the VIGP Decision.

The Commission Panel accepts that any generation option would involve long-life assets with long-term implications. Given the finding of the VIGP Decision that the CFT should be for on-Island generation, it is unreasonable and unrealistic at this point to suggest that a long-term solution was not or should not have been the purpose and intent of the CFT.

14.9 Rate Impacts

In Response to BCOAPO IR 1.18.1 (Exhibit B-20), BC Hydro conducted an analysis of the relative rate impacts of the Tier 1, Tier 2 and No Award Outcomes, assuming a F2010 in-service date for the 230 kV cable. The analysis is summarized below. The analysis does not reflect the potential cash flow arising from the disposal of the VIGP assets, which would occur in 2006.

	First Year Rate Impact (F2008)	Levelized Cost (Real $2002 @6%)	Levelized Cost Premium (Savings) Relative to Tier 1 Outcome
Tier 1 (Selected Tender)	2.18%	$65.6/MWh	0%
Tier 2	1.64%	$66.3/MW.h	1%
No Award	3.28%	$63.9/MW.h	-3%

The Commission Panel notes that the first-year rate impact does not provide a meaningful indication of the rate impact of each alternative over the life of the project. The levelized cost of the alternatives provides a more meaningful comparison of possible rate impacts over the life of the project, all things being equal. In this regard, the No Award would appear to have a lower levelized cost than Tier 1. However, the Commission Panel also notes this does not reflect the possible incremental cashflows associated with the DPP transfer agreement in 2006. The Commission Panel also notes the uncertainty in cost estimates relative to the small differences among the three options under the expected value assumptions used for this analysis. Finally, the rate impacts do not reflect qualitative factors such as differences in cost certainty and reliability. With respect to these considerations, the Commission Panel believes that the Tier 1 outcome is superior to the Tier 2 or No Award outcomes and that could also justify a small premium for Tier 1 if, in fact, there is any.

15.0 COMMISSION DECISION

The Commission Panel accepts the EPA with Duke Point Power, as set out in Confidential Exhibit B-4 and amended by Exhibit B-73, as filed by BC Hydro pursuant to section 71 of the Utilities Commission Act, subject to BC Hydro purchasing gas transportation from TGVI and filing a long-term firm gas transportation service agreement ("TSA") with TGVI for service to the Duke Point Power plant and ICP within 45 days of the February 17, 2005 Order. Given the urgency of the supply situation on Vancouver Island, the acceptance of the EPA for filing as an energy supply contract is further subject to the following directions:

(i) within 10 days of the February 17, 2005 Order, BC Hydro is to provide written notice to the Commission of its intention to proceed with the EPA; and

(ii) within 45 days of the February 17, 2005 Order, BC Hydro is to notify the Commission if it has been unable to reach an agreement on the terms of a TSA with TGVI; and

(iii) in the event of failure to reach an agreement on the terms of a TSA with TGVI, or in the event a filed TSA is not acceptable to the Commission and the Commission does not approve the terms of a filed TSA, either wholly or in part, BC Hydro is to apply to the Commission for further direction.

The Commission Panel has not made any Decision regarding the disposition of the $50 million payment from DPP under the VIGP Transfer Agreement, and has therefore ordered BC Hydro to carry forward this payment in a designated deferral account. This designated deferral account is to be separate from the designated account approved by Commission Order No. G-54-04. The application for disposition of both deferral accounts is to be made concurrently.

The Commission Panel acknowledges some deficiencies within the CFT process conducted by BC Hydro but finds no compelling evidence that the outcome of the competitive bidding process is not in the public interest and should therefore be overturned, particularly in light of the imminent capacity shortfall on Vancouver Island commencing in the winter of 2007/08 with the zero rating of the HVDC line. The Commission Panel notes that all of the non-winning bidders in the CFT will have an opportunity to participate again in future calls for system energy and capacity. In coming to its determination that electricity supply from the Duke Point Power project is in the public interest, the Commission Panel also considered several natural gas price forecasts and has concluded that it is likely that gas prices will drive market power prices in the Pacific region of North America for most if not all of the term of the contract with DPP.

In arriving at its Decision, the Commission Panel accepts the results of the QEM, which identified the DPP facility without duct firing as the winning Tier 1 bid. The Commission Panel acknowledges that DPP's duct firing capacity represents a very low cost source of incremental capacity, but sees no compelling reason to reject the EPA as filed given duct firing is an incremental addition to the plant, DPP plans to install the duct firing capacity, and the duct firing capacity will have little value to anyone else but BC Hydro. The Commission Panel encourages BC Hydro to secure and file an EPA for the plant's incremental duct firing capacity as soon as possible.

The Commission Panel accepts the conclusions of the broader cost-effectiveness evaluation, which confirmed the Tier 1 outcome is preferable to the Tier 2 and No Award alternatives. The Commission Panel acknowledges that there are a small number of scenarios in which Tier 1 is more costly than Tier 2 or No Award but accepts that those scenarios are less likely. These results must also be weighed against qualitative considerations such as the relative reliability of alternatives and certainty over their costs. The Commission Panel appreciates the efforts of local citizens to make their views of the project known to the Commission. However, concerns related to certain siting matters had already been considered and addressed in relation to a proposed gas-fired generation plant at Duke Point in the context of the previous extensive proceeding and the Commission's Decision on VIEC's VIGP Application. The Commission Panel also notes that the VIGP has already received an EAC, which will be transferred to the DPP facility as part of the VIGP Transfer Agreement. In this Decision, the Commission Panel is therefore concerned about BC Hydro's ability to ensure reliable service to all of the end-use customers on Vancouver Island.

Finally, the Commission Panel notes that the evaluation process and cost-effectiveness thresholds that formed the subject of this proceeding are unique to the Vancouver Island CFT. The Commission Panel expects that the deficiencies identified in this Decision will be addressed within future resource calls. These future calls should be informed by upcoming regulatory processes associated with the filing and consideration of the REAP, the ROR and the IEP.

As stated in the Commission's October 29, 2004 Decision on BC Hydro's 2004-05 and 2005-06 Revenue Requirements, this Commission Panel recognizes that the appropriate regulatory review of an executed EPA awarded following a competitive process needs to be determined with consideration given to transaction costs and the need for the parties to the contract to proceed as efficiently and expeditiously as possible (October 29,2004 Decision, pp. 119, 120). In most circumstances, the competitive process should be sufficient to establish that the awarded contract was the most cost-effective bid. In that proceeding, IPPs had expressed the view that it is essential that they learn as early as possible where there is significant regulatory concern with respect to any contracts they are entering into with BC Hydro.

In its October 29, 2004 Decision, the Commission suggested that if BC Hydro desires an efficient and effective regulatory process, it is incumbent upon BC Hydro to design its competitive processes so that there is a reasonable opportunity for the Commission to comment on the terms and conditions of EPAs prior to the awarding of contracts.

The Commission Panel also expects BC Hydro to review with stakeholders the detailed procedures and policies it has adopted to determine the dependable capacity of various types of gas-fired, coal-fired, cogeneration, hydroelectric, wind and biomass generating units. The Commission Panel suggests the ROR filing and review process may provide an appropriate forum for such a review. BC Hydro should also consider whether project-specific procedures are necessary or appropriate for assigning dependable capacity values to the foregoing classifications of generating units for system planning purposes. This information is to be submitted prior to the next EPA application, or in conjunction with the next REAP, ROR, or IEP filing.

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER E-1-05

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

and

A Filing by British Columbia Hydro and Power Authority
Call for Tenders for Capacity on Vancouver Island
Review of Electricity Purchase Agreement

BEFORE: R.H. Hobbs, Chair
L.A. Boychuk, Commissioner February 17, 2005

O R D E R

WHEREAS:

A. On November 19, 2004, British Columbia Hydro and Power Authority ("BC Hydro") submitted to the British Columbia Utilities Commission ("Commission") the Electricity Purchase Agreement ("EPA") and Vancouver Island Generation Project Transfer Agreement ("VIGP Transfer Agreement") with Duke Point Power Limited Partnership ("Duke Point Power") and a Report on the BC Hydro Call for Tenders on Vancouver Island ("CFT") Process ("the CFT Report"); and

B. Pursuant to Order No. G-99-04, on November 29 and 30, 2004, the Commission Panel held a Procedural Conference regarding an effective and efficient regulatory process for the review of BC Hydro's EPA filing and CFT Report; and

C. At the Pre-hearing Conference on November 30, 2004, the Commission Panel made determinations regarding the scope of the proceeding and directed that a Public Hearing, and a Town Hall Meeting in Nanaimo, would take place. Order No. G-106-04 established the Regulatory Agenda for the proceeding; and

D. Pursuant to Letter No. L-62-04, on December 17, 2004 the Commission Panel held a Pre-hearing Conference to consider an application by BC Hydro seeking relief with respect to responding to certain Information Requests. Commission Letter No. L-63-04 set out the Commission Panel's determinations with regard to the application for relief; and

E. Pursuant to Order No. G-106-04, on December 22, 2004 the Commission Panel held a Pre-hearing Conference to address matters that were identified in Letter No. L-64-04, including applications related to reasonable apprehension of bias, the scope of the proceeding and the disclosure of confidential information. The Pre-hearing Conference also considered revisions to the Regulatory Timetable; and

F. At the December 22, 2004 Pre-hearing Conference, Commissioner Birch recused himself from the proceeding; and

.../2

G. Following the December 22, 2004 Pre-hearing Conference, the Commission Panel issued Order No. G-119-04 which included revisions to the Regulatory Agenda established by Order No. G-106-04; and

H. Pursuant to Order No. G-119-04, the Town Hall Meeting took place on January 15, 2005 in Nanaimo, B.C.; and

I. Further pursuant to Order No. G-119-04, the Public Hearing took place from January 17 to January 28, 2005 in Vancouver, B.C.; and

J. Written Final Arguments and Reply Argument were completed by February 7, 2005. An oral argument phase was held on February 10, 2005 so counsel could respond to specific issues arising from the written argument process identified by the Commission Panel; and

K. The Commission Panel has considered the EPA, the VIGP Transfer Agreement, the Report on the BC Hydro CFT Process, the written evidence filed prior to and during the hearing, the Letters of Comment, and the written and oral arguments submitted by the parties.

NOW THEREFORE the Commission orders as follows:

1. For reasons to follow, the EPA is accepted as filed as an energy supply contract pursuant to Section 71 of the Utilities Commission Act, subject to the following conditions:

   (a) that BC Hydro purchase firm gas transportation service from Terasen Gas (Vancouver Island) Inc. ("TGVI") to serve Duke Point Power's proposed power plant at Duke Point near Nanaimo, British Columbia ("Duke Point Power Plant"); and

   (b) within 45 days of the date of this Order, that BC Hydro enter into, and facilitate the filing with the Commission of, a long-term firm gas transportation service agreement ("TSA") with TGVI to serve both the Duke Point Power Plant and the Island Cogeneration Plant at Elk Falls, near Campbell River, British Columbia.

2. The acceptance of the EPA for filing as an energy supply contract is further subject to the following directions:

   (a) within 10 days of the date of this Order, BC Hydro is to provide written notice to the Commission of its intention to proceed with the EPA; and

   (b) within 45 days of the date of this Order, BC Hydro is to notify the Commission if it has been unable to reach an agreement on the terms of a TSA with TGVI; and

   (c) in the event of a failure to reach an agreement on the terms of a TSA with TGVI within 45 days of the date of this Order, or in the event a filed TSA is not acceptable to the Commission and the Commission does not approve the terms of a filed TSA, either wholly or in part, BC Hydro is to apply to the Commission for further directions; and

.../3

(d) BC Hydro is to carry forward in a designated deferral account the $50 million payment received from Duke Point Power under the VIGP Transfer Agreement together with any carrying charges associated with that payment until BC Hydro has made an application providing for the manner of the disposition of the payment and the Commission has made a determination thereon. This designated account is to be separate from the designated account approved by Commission Order No. G-54-04. The application for disposition is to be made concurrently with the application contemplated by Commission Order No. G-54-04; and

(e) BC Hydro is to comply with any other directions in the reasons to follow.

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of February 2005.

BY ORDER

Robert H. Hobbs
Chair

APPEARANCES

G.A. FULTON P. MILLER	Commission Counsel
C.W. SANDERSON, Q,C, H. CANE J.C. KLEEFELD	British Columbia Hydro and Power Authority
L. KEOUGH	Duke Point Power Partnership Limited
A. CARPENTER	British Columbia Transmission Corporation
C. JOHNSON	Terasen Gas (Vancouver Island) Inc.
G. STAPLE	Westcoast Energy Inc.
R. B. WALLACE	Joint Industry Electricity Steering Committee
C. BOIS	Norske Skog Canada Ltd.
D. NEWLANDS	Elk Valley Coal
F. J. WEISBERG	Green Island Energy
D. LEWIS, Mayor	Village of Gold River
D. CRAIG	Commercial Energy Consumers of British Columbia
J. QUAIL. D. GATHERCOLE	“BCOAPO” B.C. Old Age Pensioners' Organization Council Of Senior Citizens Organizations Of B.C. End Legislated Poverty Society Federated Anti-Poverty Groups Of B.C. Senior Citizens' Association Of B.C. West End Seniors' Network
W. J. ANDREWS	GSX Concerned Citizens Coalition B.C. Sustainable Energy Association Society Promoting Environmentnal Conservation
R. MCKECHNIE	Himself
R. YOUNG	Gabriola Ratepayers' Associations
K. STEEVES	Himself

APPEARANCES
(continued)

J.B. WILLISTON E. CHENG R.W. RERIE P.W. NAKONDESNY	Commission Staff
TRENT BERRY ELROY SWITLISHOFF JOHN HUNTER	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 Hydro and Power Authority
Call for Tenders for Capacity on Vancouver Island
Review of Electricity Purchase Agreement

EXHIBIT LIST

Exhibit No.	Description
Commission Documents	
A-1	Order No. G-99-04 and Commission letter dated November 10, 2004 establishing a Procedural Conference to hear submissions from Participants to determine the type of regulatory process for the review of BC Hydro's Section 71 Application
A-2	Letter dated November 24, 2004 to BC Hydro and Registered Intervenors providing information that may assist participants at the Procedural Conference
A-3	BCUC Information Request No. 1 on the Call for Tenders Report to British Columbia Hydro and Power Authority
A-4	BCUC Information Request No. 1 on BC Hydro's Call for Tenders Report to British Columbia Transmission Corporation
A-5	Re-Issued BCUC Information Request No. 1 on the Call for Tenders Report and the review of the Electricity Purchase Agreement to British Columbia Hydro and Power Authority
A-6	Re-Issued BCUC Information Request No. 1 on BC Hydro's Call for Tenders and the review of the Electricity Purchase Agreement Report to British Columbia Transmission Corporation
A-7	Letter dated December 3, 2004 and Order No. G-106-04 issuing the Notice of Pre-hearing Conference, Public Hearing and Town Hall Meeting
A-8	Letter dated December 6, 2004 to British Columbia Hydro and Power Authority and Registered Intervenors confirming that the filing date for Information Requests as set out in Order No. G-106-04 (Exhibit A-7) has not changed
A-9	Letter and Information Request No. 2 to BC Hydro dated December 8, 2004

Exhibit No.	Description
A-10	**CONFIDENTIAL** – Letter and Information Request No. 3 dated December 8, 2004 to BC Hydro (Confidential, for Panel and BCUC Staff, not for posting)
A-11	**CONFIDENTIAL** – Letter dated December 10, 2004 to BC Hydro regarding Information Request No. 3 - Exhibit A-10 (Confidential, for Panel and BCUC Staff, not for posting)
A-12	Letter No. L-62-04 dated December 15, 2004 establishing a Pre-hearing Conference to hear submissions on BC Hydro's December 14, 2004 Letter identifying Information Requests that are outside the scope of the proceeding or that BC Hydro intends to decline to respond (Exhibit B-8)
A-13	Letter No. L-63-04 dated December 20, 2004 approving BC Hydro's application for relief of the information requests identified in Schedule A to Exhibit B-8
A-14	Letter No. L-64-04 dated December 20, 2004 issuing the Agenda for Pre-hearing Conference No. 2 regarding Exhibit B-8
A-15	Commission Staff position on relief sought by BC Hydro in Exhibit B-8
A-16	Order No. G-119-04 and Commission Letter dated December 24, 2004 establishing a Revised Regulatory Agenda and setting out a number of Commission Determinations resulting from the Pre-hearing Conference of December 22, 2004
A-17	Letter No. L-1-05 dated January 5, 2005 regarding the Georgia Straight Crossing Concerned Citizens' Coalition Application for Admission of Evidence from the Vancouver Island Generation Project Proceeding (Exhibit C20-12)
A-18	E-mail dated January 6, 2005 from Commission Counsel granting an extension to midnight January 6, 2005 to Màiri McLennan to file Intervenor Evidence
A-19	Letter dated January 6, 2005 issuing Reasons for Decision for Order No. G-119-04 (Exhibit A-16)
A-20	Letter dated January 6, 2005 and Order No. G-1-05 regarding Duke Point Power's December 28, 2004 application for two Orders
A-21	Letter dated January 6, 2005 approving an extension of the filing of Intervenor Evidence to midnight January 6, 2004
A-22	Letter dated January 7, 2005 providing Participants with information on the public hearing process

Exhibit No.	Description
A-23	Letter dated January 10, 2005 requesting participants to advise the Commission whether they intend to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
A-24	Letter dated January 11, 2005 requesting comments from participants on the procedural matters raised in BC Hydro's January 10, 2005 letter (Exhibit B-40)
A-25	Letter dated January 11, 2005 denying GSXCC-BCSEA request to order BC Hydro to provide details regarding the peak load of 2250 MW in advance of the hearing
A-26	Letter dated January 11, 2005 adopting the three headings set forth in BC Hydro's January 10, 2005 response (Exhibit B-41) to JIESC's letter of January 7, 2004 (Exhibit C19-3)
A-27	Letter and Information Request dated January 11, 2005 to Green Island Energy Ltd.
A-28	Letter and Information Request dated January 11, 2005 to Duke Point Power Limited Partnership
A-29	Letter and Information Request No. 1 dated January 11, 2005 to the Georgia Straight Crossing Concerned Citizens' Coalition
A-30	Letter and Information Request No. 1 dated January 11, 2005 to NorskeCanada Ltd.
A-31	Letter and Information Request No. 1 dated January 11, 2005 to Sea Breeze Power Corp.
A-32	Letter and Information Request No. 1 dated January 11, 2005 to the Joint Industry Electricity Steering Committee
A-33	Letter and Information Request No. 1 dated January 11, 2005 to the Commercial Energy Consumers
A-34	Letter dated January 12, 2005 requesting BCTC to provide a witness panel for cross-examination of its December 23, 2004 Evaluation of the NorskeCanada Demand Management proposal
A-35	Letter No. L-2-05 dated January 12, 2005 to Vanport Sterilizers Inc. regarding request for Reconsideration of Commission Order No. G-119-04

Exhibit No.	Description
A-36	Letter No. L-3-05 dated January 12, 2005 and Reasons for Decision regarding the December 16, 2004 Joint Industry Electricity Steering Committee reconsideration application
A-37	Letter dated January 12, 2005 clarifying the status of the compact disc that Willis Energy Services Ltd. filed on January 7, 2005 (Exhibit C9-13)
A-38	Letter dated January 13, 2005 regarding participant comments on procedural matters and the proposed time line for witness panels attached as a schedule to this letter
A-39	Pages from Terasen Gas (Vancouver Island) Inc. Argument dated December 21, 2004
A-40	Part 4 - Fuel Supply Certainty Guidelines Issued January 6, 2004 (Revised June 30, 2004)
A-41	**CONFIDENTIAL** – BCUC staff questions for Panel 2 (Confidential, for Panel and BCUC Staff, not for posting)
A-42	Table – Appendix E: Rated Outputs and Efficiencies of GE CCGTS
A-43	British Columbia Transmission Corporation December 23, 2004 letter filing its evaluation of the NorskeCanada Demand Management proposal in response to Commission directive on page 34 of the Commission's November 19, 2004 Decision into BCTC's Capital Plan Application
A-44	BC Hydro Information – Questions & Answers on the following topics: • Interconnection and Cost Allocation • Use of Generation Shedding to Avoid Cut-Plane Upgrades • Transmission system Upgrade for Capacity Projects North of Dunsmuir • Cut Plane D Capacity Deficiency for 2007/08 Only • VIGP Facilities Agreement and Interconnection Agreement
A-45	Letter No. L-8-05 dated January 27, 2005 issuing Reasons for Decision regarding the GSX Concerned Citizens Coalition, B.C., Sustainable Energy Association and Society Promoting Environmental Conservation (collectively "GSXCCC et al.") January 14, 2005 application for reconsideration of certain decisions made by the Commission Panel regarding the conduct of the proceedings

Exhibit No.	**Description**
Applicant Documents	
B-1	Call for Tenders for Capacity and Associated Energy Supply on Vancouver Island - Report on the Call for Tenders Process conducted by BC Hydro dated November 19, 2004
B-2	Letter dated November 25, 2004 filing the Duke Point Project Milestone Schedule in response to Commission's letter dated November 24, 2004 (Exhibit A-2)
B-3	Facsimile dated November 28, 2004 providing a list of Information Requests BC Hydro believes should be considered within the scope of the Call for Tenders Review
B-4	**CONFIDENTIAL** – Electricity Purchase Agreement (Capacity and Associated Energy) Vancouver Island and VIGP Transfer Agreement, filing dated November 19, 2004 (Confidential, for Panel and BCUC Staff, not for posting)
B-5	**CONFIDENTIAL** – Letter dated December 2, 2004 filing the Evaluation Models and Input Data (Confidential, for Panel and BCUC Staff, not for posting – CD Disk)
B-6	Letter dated December 3, 2004 enclosing redacted Electricity Purchase Agreement
B-7	Letter dated December 6, 2004 regarding the established process for reconsideration applications
B-8	Letter dated December 14, 2004 identifying Information Requests that are outside the scope of the proceeding or that BC Hydro intends to decline to respond
B-9	BC Hydro response dated December 17, 2004 to BCUC Information Request No. 1
B-10	**CONFIDENTIAL** – Response dated December 17, 2004 to BCUC Confidential Information Request No. 1 (Confidential, for Panel and BCUC Staff, not for posting)
B-11	Letter dated December 20, 2004 from BC Hydro Counsel (Lawson Lundell) requesting confirmation whether the BCOAPO and the JIESC will be proceeding with their reconsideration applications

Exhibit No.	Description
B-12	Responses dated December 20, 2004 to Information Requests from The BC Old Age Pensioners Organization *et al*., Green Island Energy, the GSX Concerned Citizens Coalition and the Joint Industry Electricity Steering Committee
B-13	Letter dated December 21, 2004 to Mr. William Andrews, Counsel for the GSX Concerned Citizens Coalition regarding the Commission's confidentiality ruling on Exhibit B-8
B-14	Letter dated December 21, 2004 outlining BC Hydro's approach for responding to outstanding Information Requests
B-15	**CONFIDENTIAL** – December 20, 2004 filing of responses to BCUC Information Request No. 2 (Exhibit A-9) (Confidential, for Panel and BCUC Staff, not for posting)
B-16	Response dated December 20, 2004 to BCUC Information Request No. 2 and updates issued December 23, 2004
B-17	**CONFIDENTIAL** – December 23, 2004 filing of responses to outstanding BCUC Confidential Information Requests (Confidential, for Panel and BCUC Staff, not for posting)
B-18	Responses dated December 22, 2004 to Information Requests from Erik Andersen, BC Sustainable Energy Association, Gabriola Island Ratepayers and Residents Association; John Hill, Bob McKechnie, Màiri McLennan, Sea Breeze Power Corp, Keith Steeves and the Village of Gold River
B-19	E-mail dated December 29, 2004 attaching Appendix 3 to the Electricity Purchase Agreement as per Commission Order No. G-119-04
B-20	Response issued December 23, 2004 to Information Requests from BCOAPO, Green Island Energy, GSX Concerned Citizens Coalition and JIESC
B-21	Response issued December 23, 2004 to Information Requests from BC Sustainable Energy Association, Village of Gold River, Bob McKechnie, Màiri McLennan and Sea Breeze Pacific Regional Transmission System Inc.
B-22	Letter dated January 4, 2005 regarding reconsideration application by the JIESC
B-23	Letter dated January 4, 2005 responding to the two letters of December 24, 2004 from the JIESC

Exhibit No.	Description
B-24	**CONFIDENTIAL** - Response issued December 23, 2004 to Re-issued Commission Information Request No. 1.24.7 (Confidential, for Panel and BCUC Staff, not for posting)
B-25	Letter dated January 4, 2005 responding to Weisberg Law Corporation's letters of December 24, and 30, 2004
B-26	Letter dated January 4, 2005 to William J. Andrews, counsel for the GSX Concerned Citizens Coalition, regarding his letters of December 23, 29 and 30, 2004
B-27	Letter dated January 5, 2005 regarding Mr. Andrews correspondence of December 28, 2004 relating to VIGP evidence
B-28	Letter dated January 5, 2005 to William J. Andrews replying to his letter of January 4, 2005
B-29	Response issued December 17, 2004 to Re-issued Commission Information Request No. 1.14.3, 1.14.4 and 1.20.1
B-30	Revised responses dated January 5, 2005 to GSX Concerned Citizens Coalition Information Requests No. 1.16.2, 1.22.3.1 and 1.22.3.2
B-31	Second revised response issued January 6, 2005 to GSX Concerned Citizens Coalition Information Request No. 1.22.3.2
B-32	Letter dated January 5, 2005 with comments on various Intervenor requests for extension to the filing deadline for Intervenor evidence
B-33	Letter dated January 6, 2005 regarding the JIESC's Information Request No. 2
B-34	Letter dated January 6, 2005 responding to Màiri McLennan's letter of January 3, 2005
B-35	Letter and direct evidence dated January 6, 2005
B-35A	Resume of Kenneth H. Tiedemann
B-36	Revised responses dated January 7, 2005 to Gold River Information Request Nos. 1.1.11 and 1.1.17

Exhibit No.	Description
B-37	**CONFIDENTIAL** – Revised response issued January 6, 2005 to Commission Information Request No. 2.70.1, 2.73.1 and 2.73.2 (Confidential, for Panel and BCUC Staff, not for posting) WITHDRAWN - 2.70.1 withdrawn by letter dated January 12, 2005 (Exhibit B-50)
B-38	Letter dated January 10, 2005 addressing Mr. Andrews' letter of January 8, 2005 (Exhibit C20-22)
B-39	Letter dated January 10, 2005 regarding Calpine's letter of January 6, 2005 (Exhibit E-123)
B-40	Letter dated January 10, 2005 regarding Commission letter dated January 7, 2005 (Exhibit A-22) and requesting that the Commission consider additional steps in this proceeding
B-41	Letter dated January 10, 2005 regarding the JIESC's revised letter of January 7, 2005 (Exhibit C19-13)
B-42	Letter dated January 11, 2005 regarding the BCOAPO et al.'s letter dated January 10, 2005 (Exhibit C3-6)
B-43	Information Request No. 1 to the JIESC dated January 11, 2005
B-44	Information Request No. 1 to Green Island Energy Ltd. dated January 11, 2005
B-45	Information Request No. 1 to the Commercial Energy Consumers of BC dated January 11, 2005
B-46	Information Request No. 1 to the GSX Concerned Citizens Coalition and the BC Sustainable Energy Association dated January 11, 2005
B-47	Letter dated January 11, 2005 regarding two letters of the same date from the BC Old Age Pensioners Organization et al.
B-48	Revised Response dated January 11, 2005 to Commission Information Request 2.55.1
B-49	Response dated January 12, 2005 to Intervenor submissions on process issues

Exhibit No.	**Description**
B-50	Letter dated January 12, 2005 regarding responses to Commission Information Request 1.33.2, 1.41.1 and 2.76.1, and confidential response to Information Request 2.70.1
B-51	**CONFIDENTIAL** – Response issued January 12, 2005 to Commission Information Request No. 2.70.1 (Confidential, for Panel and BCUC Staff, not for posting)
B-52	Letter dated January 13, 2005 regarding the evidence of NorskeCanada
B-53	Letter dated January 14, 2005 requesting admission of evidence from the VIGP proceeding
B-54	Letter dated January 14, 2005 providing evidence prepared in response to Exhibit A-13, responding to the JIESC Information Request No. 2.9.0 and advisement that the Direct Testimony of Mr. Steven Eckert will replace Mr. Lowry on BC Hydro Panel 2
B-54A	1-Page "Amendment to Direct Testimony of Steve Eckert - Question 9 - responsibility for responses to Information Requests"
B-55	Letter and revised responses dated January 16, 2005 to Information Requests to BCOAPO 1.22.2(a), Gold River 1.2.11 and 1.2.13, Sea Breeze 1.6.0 and JIESC 1.5.0(a), 17.0 (c), 1.7.0 (b)(v) and the opening statement of Bev Van Ruyven
B-56	Letter to R. Brian Wallace, Bull Housser & Tupper dated January 17, 2005 regarding advance notice of witness evidence
	CONFIDENTIAL –Attachment (not for posting)
B-57	Letter to William J. Andrews dated January 17, 2005 regarding advance notice of witness evidence
	CONFIDENTIAL –Attachment (not for posting)
B-58	Letter to Weisberg Law Corporation dated January 17, 2005 regarding advance notice of witness evidence
	CONFIDENTIAL –Attachment (not for posting)
B-59	Letter to Màiri McLennan dated January 17, 2005 regarding advance notice of witness evidence
	CONFIDENTIAL –Attachment (not for posting)

Exhibit No.	Description
B-60	Vancouver Island Call For Tenders – Bidder's Tender Workshop slides dated July 7, 2004
B-61	Document entitled: BC Hydro - Info – Q&As – Treatment of VIGP Asset Price versus Salvage Value – dated November 26, 2003
B-62	Data Tables – JIESC Supplementary Information Request 2.10.0(a) and 2.10.0(b)
B-63	Undertaking – Transcript Reference: Volume 7: Pages 1406, 1407
B-64	Undertaking – Transcript Reference: Volume 6: Pages 1245, 1250
B-65	Undertaking – Transcript Reference: Volume 7: Page 1424
B-66	Letter dated January 19, 2005 responding to Mr. Andrews letter of January 14, 2005 seeking Reconsideration of certain orders
B-67	Letter dated January 7, 2005 filing a Revised Electric Load Forecast, 2004/05 to 2024/25.
B-68	Document entitled "Vancouver Island Daily Peak – January 1, 200t through January 15, 2005"
B-69	Document entitled "VI CFT Tender Phase Completeness and Conformity Procedure"
B-70	Revised Response dated January 20, 2005 to Green Island Energy Ltd. Information Request No. 1.11.2 dated December 8, 2004
B-71	Revised Response dated January 20, 2005 to GSX Concerned Citizens Coalition Information Request No. 1.28.1 dated December 8, 2004
B-72	Response to Undertaking dated January 18, 2005 to GSX Concerned Citizens Coalition (Transcript Reference: Volume 7, Pages 1621, 1622)
B-73	Electricity Purchase Agreement and VIGP Transfer Agreement – Amending Agreement No. 1 dated January 20, 2005 between Duke Point Power Limited Partnership and British Columbia Hydro and Power Authority
B-74	Response to Undertaking dated January 20, 2005 to the Joint Industry Electricity Steering Committee (Transcript Reference: Page 1949)
B-75	Response to Undertaking dated January 20, 2005 to GSX Concerned Citizens Coalition (Transcript Reference: Volume 9, Page 2077)

Exhibit No.	**Description**
B-76	Response to Undertaking dated January 20, 2005 to GSX Concerned Citizens Coalition (Transcript Reference: Volume 9, Page 2045)
B-77	Response to Undertaking dated January 20, 2005 to GSX Concerned Citizens Coalition (Transcript Reference: Volume 9, Page 2061)
B-78	Response to Undertaking dated January 17, 2005 to the Joint Industry Electricity Steering Committee (Transcript Reference: Volume 6, Page 1237)
B-79	Response to Undertaking dated January 18, 2005 to The BC Old Age Pensioners Organization *et al*. and Chairman Hobbs (Transcript Reference: Page 1596)
B-79A	**CONFIDENTIAL** – Table outlining the progression of bidders and projects through the various phases of CFT, Response to Undertaking dated January 18, 2005 to Chairman Hobbs (Transcript Reference: page 1596) (Confidential, for Panel and BCUC Staff, not for posting)
B-80	Response to Undertaking dated January 18, 2005 to GSX Concerned Citizens Coalition (Transcript Reference: Volume 7, Pages 1616-1619)
B-81	Response to Undertaking dated January 20, 2005 to Mr. Trent Berry, BCUC Consultant (Transcript Reference: Volume 8, Pages 1659-1663)
B-81A	Graphs – Market Heat Rate for Select Forecasts: Reproduction of Fulton Figure 1 – Figure 1b
B-81B	Graphs – Market Heat Rate for Select Forecasts: Reproduction of Fulton Figure 1 – Figure 1c
B-82	Table 1 - January 2005 NYMEX Natural Gas, Source: Bloomberg
B-83	The Electricity Market Module of the National Energy Modeling System – Model Documentation Report dated March 2004
B-84	Article from “The Desk” – Annual End of Year Issue December 2004
B-85	Table of outstanding BC Hydro Information Requests
B-86	Response to NorskeCanada Information Request at Volume 7, Pages 1356-1358
B-87	Response to Green Island Energy Information Request at Volume 7, Page 1460
B-88	Response to Gold River Information Request at Volume 7, Page 1510
B-88A	Revised response to Information Request at Volume 7, Page 1510

Exhibit No.	Description
B-89	Response to NorskeCanada Information Request at Volume 9, Page 1996
B-90	Response to GSX Concerned Citizens Coalition Information Request at Volume 9, Page 2068
B-91	Response to Commission Information Request at Volume 9, Pages 2155-2156
B-92	Response to Màiri McLennan's outstanding Information Requests
B-93	**CONFIDENTIAL** – Response to question regarding Fuel Assumptions for temporary generators (Confidential, for Panel and BCUC Staff, not for posting)
B-94	**CONFIDENTIAL** – Response to Information Request at Volume 9, Page 2156, Lines 23 to 26 (Confidential, for Panel and BCUC Staff, not for posting)
B-95	**CONFIDENTIAL** – Response to Information Request regarding Network upgrade costs (Confidential, for Panel and BCUC Staff, not for posting)
B-96	**CONFIDENTIAL** – Response to Information Request regarding definition of Tier 2 Issue (Confidential, for Panel and BCUC Staff, not for posting)
B-97	Letter dated January 25, 2005 attaching rebuttal evidence and advising that BC Hydro will be calling such evidence and asking that it be circulated to the hearing panel
B-97A	Correction table to Page 8 of Mr. Pickel's evidence
B-98	Response to Information Request at Volume 10, Pages 2203-2205
B-99	Revised attachment A to Appendix J of Exhibit B-1 based on December load forecast
B-99A	**CONFIDENTIAL** – Spreadsheets used to produce Exhibit B-99 (Confidential CD Rom for Panel and BCUC Staff, not for posting)
B-100	Response to Information Request at Volume 10, Pages 2203-2205, Items 40 and 41 on Exhibit B-85
B-100A	**CONFIDENTIAL** – Updated response to Information Request 1.14.2.3 (Confidential, for Panel and BCUC Staff, not for posting)
B-101	Updated Response to Commission Information Request 1.14.7.2
B-102	**CONFIDENTIAL** – Updated Responses to Commission Information Request Nos. 1.15.5 and 2.73.1

Exhibit No.	**Description**
B-103	**CONFIDENTIAL** - Responses to requests of Mayor Lewis – Transcript Reference: Volume 9: Pages 2133-2142
B-104	Responses to GSX Concerned Citizens Coalition Undertakings - Reference: Exhibit C20-14, Exhibit B-57 and Andrews letter dated January 24, 2005
B-105	Letter dated November 18, 2004 from Mary Hemmingsen to Yakout Mansour
B-106	Undertaking – Transcript Reference: Volume 15: Pages 3113, 3160-3162
B-107	Undertaking – Transcript Reference: Volume 15: Page 3134
B-108	Undertaking – Transcript Reference: Volume 15: Page 3196

Intervenor Documents

C1-1	**STEEVES, KEITH** – Notice of Intervention dated November 12, 2004
C1-2	Information Requests – Round 1 dated December 7, 2004
C1-3	Letter and evidence submission dated December 24, 2004
C2-1	**NORKSECANADA LTD.** – Notice of Intervention dated November 15, 2004 from Dennis Fitzgerald
C2-2	Letter from Miller Thompson LLP dated December 21, 2004 regarding their retention as counsel by NorskeCanada Ltd.
C2-3	Letter from Miller Thompson LLP dated December 21, 2004, filing as part of NorskeCanada's Evidence their Demand Management Proposal dated September 2, 2004
C2-4	Letter from Miller Thompson LLP dated January 5, 2005 regarding the Phase 1 reconsideration process
C2-5	Letter dated January 11, 2005 regarding the intent of NorskeCanada to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal and that its witness panel will be prepared to answer questions regarding the Evaluation Report
C2-6	Letter dated January 12, 2005 commenting on the procedural process

Exhibit No.	Description
C2-7	Letter dated January 13, 2005 informing the Commission that the witness panel for NorskeCanada will be Mr. Robert H. Lindstrom and Mr. Dennis Fitzgerald and requesting that the NorskeCanada panel be scheduled to follow the BCTC panel
C2-8	Letter dated January 14, 2005 confirming NorskeCanada evidence is NorskeCanada Demand Management Proposal
C2-9	Letter and response dated January 17, 2005 to GSX Concerned Citizens Coalition Information Request
C2-10	Letter and response dated January 17, 2005 to Commission Information Request No. 1
C2-11	Letter and responses dated January 17, 2005 to Duke Point Power Limited Partnership Information Request
C2-12	Letter dated January 20, 2005 regarding response to GSX Concerned Citizens Coalition request for review and reconsideration of certain decisions
C2-13	Document entitled "Exploring Vancouver Island's Energy Future: *A Workshop with Be Hydro & Rocky Mountain Institute (Final report dated September 29, 2003, Prepared by the Rocky Mountain Institute, Joel N. Swisher, PhD, PE, Project Manager)*
C2-14	Letter dated January 20, 2005 filing the opening statement of Mr. Robert Lindstrom, Vice President, Strategy, NorskeCanada
C3-1	**BC OLD AGE PENSIONERS ORGANIZATION *ET AL*.** – Notice of Intervention dated November 15, 2004 from the British Columbia Public Interest Advocacy Centre on behalf of its clients
C3-2	Letter dated December 3, 2004 commenting on the following issues raised at the Procedural Conference: • Confidentiality • the principal issue defined by the Commission • in-camera review with BC Hydro and Duke Point
C3-3	Information Requests – Round 1 dated December 7, 2004
C3-4	Letter dated December 15, 2004 requesting that the Confidentiality issue ruled on by the Commission on November 30, 2004 be placed on the Agenda for the December 17, 2004 Pre-hearing Conference established to review Exhibit B-8

Exhibit No.	Description
C3-5	Letter dated December 21, 2004 responding to BC Hydro Counsel's letter of December 20, 2004 (Exhibit B-11)
C3-6	Letter dated January 10, 2005 regarding BC Hydro's non-compliance with Commission Order No. G-119-04 and BCOAPO et al. Information Requests
C3-7	Letter dated January 10, 2005 withdrawing the first Order requested regarding Part 1 and continuing to seek the second Order (Exhibit C3-6)
C3-8	Letter dated January 11, 2005 replying to BC Hydro's letter of the same date regarding the BCOAPO et al. application for an Order for Information Request responses
C3-9	E-mail dated January 11, 2005 regarding the intent of BCOAPO et al. to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
C3-10	Letter dated January 11, 2005 in response to Exhibit B-40 concerning BC Hydro's procedural proposals in this matter
C3-11	Letter dated January 12, 2005 regarding BC Hydro's evidentiary panels
C3-12	Table entitled "BC Hydro CFT Projects"
C4-1	**BC CITIZENS FOR PUBLIC POWER SOCIETY** – Notice of Intervention dated November 17, 2004 from Mark Veerkamp
C5-1	**VILLAGE OF GOLD RIVER** – Notice of Intervention dated November 17, 2004 from Mayor David Lewis
C5-2	Submission commenting on the Vancouver Island Call for Tenders review process from Mayor David Lewis
C5-3	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C5-4	Two letters dated December 21, 2004 regarding Gold River's attendance at the Pre-Hearing Conference of December 22, 2004 and comments
C5-5	E-mail dated December 24, 2004 with concerns regarding the December 22, 2004 meeting held in Vancouver
C5-6	Letter and written evidence dated January 6, 2005

Exhibit No.	Description
C5-7	E-mail dated January 4, 2005 regarding panel determinations relative to BC Hydro's objections to Gold River Information Request No. 1
C5-8	Letter dated January 11, 2005 regarding the BC Hydro letter dated January 10, 2005 providing direction on procedural process (Exhibit B-40)
C5-9	Letter dated January 12, 2005 with comments on Exhibit E-140
C5-10	Panel Opening Statement dated January 26, 2005 of David Lewis, Mayor, Village of Gold River
C6-1	**BRITISH COLUMBIA TRANSMISSION CORPORATION** – Notice of Intervention dated November 17, 2004 from Cameron Lusztig
C6-2	Response dated December 17, 2004 to Commission Information Request No. 1 to British Columbia Transmission Corporation
C6-3	Letter to BCUC dated December 29, 2004 in response to Duke Point Power Limited Partnership's letter of December 28, 2004
C6-4	Letter dated January 13, 2005 responding to Commission letter dated January 12, 2005 requesting that BCTC provide a witness panel (Exhibit A-34)
C6-5	Letter and response dated January 17, 2005 to GSX Concerned Citizens Coalition/BC Sustainable Energy Association Information Request
C6-6	Letter and response dated January 17, 2005 to Duke Point Power Limited Partnership Information Request
C6-7	Response to Information Request at Volume 10, Page 2398
C6-8	Response to Information Request at Volume 10, Page 2400
C6-9	Response to Information Request at Volume 10, Page 2402
C7-1	**PARR, JIM** – Notice of Intervention dated November 18, 2004
C8-1	**ELLIOTT ENERGY SERVICES LTD.** – Notice of Intervention dated November 19, 2004 from John Elliott

Exhibit No.	**Description**
C9-1	**GREEN ISLAND ENERGY LTD.** – Notice of Intervention dated November 19, 2004 from Sean Ebnet
C9-2	Letter dated November 26, 2004 from Weisberg Law Corporation regarding their retention as counsel for Green Island Energy and a Submission listing the Principal Issues Green Island Energy would like the Commission to examine during the review
C9-3	Term Sheet dated November 18, 2004
C9-4	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C9-5	Letter dated December 16, 2004 responding to BC Hydro's December 14, 2004 letter (Exhibit B-8)
C9-6	Letter dated December 24, 2004 from Weisberg Law Corporation requesting that BC Hydro provide Appendix 3 with additional information disclosed as directed by the Commission, that they provide copies of all Response to Information Requests to which confidentiality no longer applies, and expressing concerns regarding BC Hydro's Response to Green Island Energy Ltd. Information Requests No. 1.13.1 and 1.13.2
C9-7	Letter to BCUC dated December 30, 2004 from Weisberg Law Corporation regarding the Duke Point Power Limited Partnership letter dated December 28, 2004
C9-8	Letter dated December 31, 2004 regarding clarification by BC Hydro to responses to certain Green Island Energy Ltd. Information Requests
C9-9	Letter dated January 4, 2004 (5) regarding the Phase 1 reconsideration process for the JIESC reconsideration application
C9-10	Evidence of Green Island Energy Ltd. dated January 6, 2005
C9-11	Letter dated January 11, 2005 responding to Mr. Sanderson's letter to the Commission dated January 10, 2005
C9-12	E-mail dated January 11, 2005 regarding the intent of Green Island Energy Ltd. to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal

Exhibit No.	Description
C9-13	**CONFIDENTIAL** – Compact Disc filed on January 7, 2005 by Willis Energy Services Ltd. on behalf of Green Island Energy (Confidential, for Panel and BCUC Staff, not for posting)
C9-14	Letter dated January 13, 2004 (5) regarding the price information for the Green Island Energy Ltd. bid in the Call For Tenders
	CONFIDENTIAL – Price Information Form (Confidential, for Panel and BCUC Staff, not for posting)
C9-15	Letter dated January 17, 2005 regarding response to Duke Point Power Limited Partnership Information Request
C9-16	Response dated January 17, 2005 to Duke Point Power Limited Partnership Information Request
C9-17	Letter and response dated January 17, 2005 to BC Hydro Information Request No. 1
C9-18	Letter and response dated January 17, 2005 to Commission Information Request No. 1
C9-19	Letter dated January 17, 2005 regarding back up information referenced in BCUC Information Request No. 1.3
	CONFIDENTIAL – Appendix A - back up to BCUC IR 1.3 (Confidential, for Panel and BCUC Staff, not for posting)
C9-20	Response to Undertaking at Volume 11, Page 6 - Tables reflecting amendment of firm gas transportation adder
C10-1	**WESTCOAST ENERGY INC.** – Notice of Intervention dated November 23, 2004 from Greg Staple
C11-1	**RAINBOTH, ANN** – Notice of Intervention dated November 23, 2004
C12-1	**ENCO POWER COMPANY** – Notice of Intervention dated November 24, 2004 from Charles E. Martin
C13-1	**HILL, JOHN A.** – Notice of Intervention dated November 24, 2004
C13-2	Letter of Comment dated November 28, 2004

Exhibit No.	Description
C13-3	Information Request No. 1 dated December 8, 2004
C13-4	Letter dated January 4, 2005 regarding the reconsideration process for the JIESC reconsideration application
C13-5	Evidence of John A Hill dated January 6, 2005
C13-6	Letter dated January 25, 2005 regarding C20-35
C14-1	**WILLIAMS GAS PIPELINE COMPANY** – Notice of Intervention dated November 23, 2004 from Steven W. Snarr
C14-2	Intervenor Withdrawal Request dated December 10, 2004
C15-1	**GRIGNON, PAUL** – Notice of Intervention dated November 24, 2004
C16-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BC SEA)** – Notice of Intervention dated November 24, 2004 from Guy Dauncey
C16-2	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C16-3	Letter dated December 20, 2004 advising that it would be joining its intervention with the GSX Concerned Citizens Coalition
C16-4	Letter dated December 14, 2004 regarding joining the GSX Concerned Citizens Coalition intervention, and the BC Sustainable Energy Association's purpose and concerns in this process
C17-1	**DUKE POINT POWER LIMITED**– Notice of Intervention dated November 25, 2004 from Loyola Keough
C17-2	Letter dated December 28, 2004 seeking two additional Orders and to confirm that the Commission intends that BC Hydro provide a witness to speak to the Evidence on record in response to Information Requests
C17-3	Letter dated January 3, 2005 providing comments in regard to the JIESC reconsideration application
C17-4	Letter dated January 3, 2005 responding to points raised in the British Columbia Transmission Corporation letter dated December 29, 2004 and the Green Island Energy Ltd. letter of December 30, 2004

Exhibit No.	Description
C17-5	Letter dated January 4, 2005 responding to the JIESC letter of December 28, 2004
C17-6	Letter and evidence dated January 6, 2005
C17-7	Letter dated January 11, 2005 regarding procedural matters
C17-8	Letter dated January 11, 2005 regarding the disclosure of confidential sections of the Electricity Purchase Agreement Appendix 3
C17-9	Letter and Information Request dated January 11, 2005 to British Columbia Transmission Corporation
C17-10	Letter and Information Request dated January 11, 2005 to Green Island Energy Ltd.
C17-11	Letter and Information Request dated January 11, 2005 to NorskeCanada
C17-12	Letter and response dated January 17, 2005 to GSX Concerned Citizens Coalition Information Request
C17-13	Letter and response dated January 17, 2005 to Commission Information Request
C17-14	Letter dated January 19, 2005 advising that the witness panel for Duke Point Power Limited Partnership will be Jeffry Myers, Harvie Campbell and Ken Spinner
C17-15	Letter dated January 19, 2005 responding to the request for Reconsideration filed on behalf of the GSX Concerned Citizens Coalition
C17-16	VIGP Hearing Day 5 – June 20, 2003 – Response to Undertaking Volume 5, Transcript Reference Pages 1031-1035
C17-17	British Columbia Utilities Commission Staff Information Request No. 1.21.2 dated 21 March 2003 - Vancouver Island Energy Response Issued April 14, 2003 - Vancouver Island Energy Corporation Application to the British Columbia Utilities Commission for a Certificate of Public Convenience & Necessity for the Vancouver Island Generation Project
C17-18	Appendix A from the Commission’s Reasons for Decision on the British Columbia Transmission Corporation’s Transmission System Capital Plan
C17-19	BCTC Letter dated December 20, 2004 filing responses to the Commission's questions provided in the its November 19,2004 Reasons for Decision (pages 27-28) on BCTC's Capital Plan Application

Exhibit No.	Description
C17-20	Response to Undertakings at Volume 10, Page 2231; Volume 10, Pages 2235; Volume 10, Page 2235-2236
C18-1	**TERASEN GAS (VANCOUVER ISLAND) INC.** – Notice of Intervention dated November 25, 2004
C18-2	Letter dated November 25, 2004 filing the LNG Project Milestone Schedule in response to Commission's letter dated November 24, 2004 (Exhibit A-2)
C19-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE** – Notice of Intervention dated November 26, 2004 from R. Brian Wallace, Bull Housser & Tupper
C19-2	Letter dated December 2, 2004 commenting on issues arising out of the November 29, 2004 Procedural Conference
C19-3	Information Request No. 1 dated December 8, 2004 to British Columbia Transmission Corporation
C19-4	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C19-5	Letter dated December 16, 2004 requesting the Commission to reconsider and rescind the November 30, 2004 ruling regarding some of the significant terms of the Electricity Purchase Agreement
C19-6	Letter dated December 21, 2004 responding to BC Hydro Counsel's letter of December 20, 2004 (Exhibit B-11)
C19-7	Letter to BC Hydro dated December 24, 2004 requesting a copy of Appendix 3 of the Electricity Purchase Agreement and copies of all Information Requests which should no longer be held confidential as per the Commission's Decision
C19-8	Letter to BC Hydro dated December 24, 2004 regarding the Joint Industry Electricity Steering Committee Information Request No. 1.1.0(1)
C19-9	Letter dated January 3, 2005 responding to the Duke Point Limited Partnership letter dated December 28, 2004
C19-10	Information Request No. 2 dated January 3, 2005
C19-11	Letter dated January 6, 2005 regarding evidence from S. Fulton and L. Guenther

Exhibit No.	Description
C19-12	Letter dated January 6 regarding the JIESC Submissions on Review and Variation of Scope Decision
C19-13	Letter dated January 6, 2005 and revision to same dated January 7, 2004 (5) regarding BC Hydro's failure to provide required information
C19-14	Letter dated January 11, 2005 regarding the intent of the JIESC to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
C19-15	Letter dated January 12, 2005 regarding procedural matters and the submissions of BCPIAC and Green Island Energy
C19-16	Letter dated January 14, 2005 requesting VIGP Hearing Record be incorporated into this Hearing
C19-17	Four Pages of Spreadsheet
C19-18	Graph entitled "QEM Model Heat Rates"
C19-19	Responses dated January 16, 2005 to BC Hydro and Commission Information Requests
C19-20	Witness Aid dated January 18, 2005 prepared for the JIESC entitled "Summary Table - Cost Effectiveness Analysis- Appendix J to CFT Report (Ex. 81)
C19-21	Excerpt from the 2004 Integrated Electricity Plan entitled "Summary of Available Resource Options"
C19-22	Letter dated January 19, 2005 responding to the GSX Concerned Citizens Coalition request for reconsideration of certain decisions
C19-23	JIESC Witness Aid entitled "Cost of Duke Point Power Generation"
C19-24	Letter dated January 19, 2005 filing supplementary evidence of Sheldon Fulton
C19-25	Opening statement dated January 2005 of Lloyd G. Guenther on behalf of the Joint Industry Electricity Steering Committee
C19-26	Excerpt from article entitled "The Western Energy Market : Inherent Risks and Market Solutions" by J. D. Roark with sidebar information by F. H. Pickel, PH.D.

Exhibit No.	**Description**
C19-27	Prepared Testimony dated March 3, 2003 of Dr. Frederick H. Pickel before the (USA) Federal Energy Regulatory Commission
C20-1	**GSX CONCERNED CITIZENS COALITION** – Notice of Intervention dated November 25, 2004 from William J. Andrews
C20-2	Letter dated December 2, 2004 requesting clarification regarding the four matters addressed in the Panel's November 30, 2004 decision: 1. public disclosure of the Electricity Purchase Agreement (EPA) and the VIGP Transfer Agreement (VTA), 2. B.C. Hydro's compliance with the Call for Tenders (CFT) not being an issue in the review, 3. the meaning of "next resource addition," and 4. the meaning of "accepted."
C20-3	Letter dated December 3, 2004 providing additional information in support of the December 2, 2004 request for clarification (Exhibit C20-2)
C20-4	Letter dated December 6, 2004 commenting on BC Hydro's December 6, 2004 letter responding to the GSX's December 2, 2004 request for clarification regarding the four matters addressed in the Panel's November 30, 2004 decision
C20-5	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C20-6	Letter dated December 14, 2004 commenting on BC Hydro's December 14, 2004 letter (Exhibit B-8)
C20-7	Letter dated December 15, 2004 requesting BC Hydro provide a table specifying the grounds for each challenged Information Request and requesting the Intervenor Evidence deadline be amended if BC Hydro does not respond to all Information Requests submitted
C20-8	Letter dated December 20, 2004 updating information provided in Exhibit C20-1 and advising that the BC Sustainable Energy Association (BC Sea) has joined its intervention with the GSX Concerned Citizens Coalition
C20-9	Letter dated December 20, 2004 concerning the procedure for the Commission's determination of BC Hydro's request for confidentiality of the Redacted portions of the Electricity Purchase Agreement

Exhibit No.	Description
C20-10	Package of print-outs from Internet websites, including a table of contents, which identifies the items
C20-11	Letter dated December 23, 2004 from William J. Andrews on behalf of the GSX Concerned Citizens Coalition and the BC Sustainable Energy Association regarding BC Hydro’s response to GSC Concerned Citizens Coalition Information Request No. 1.22.3.1 and No. 1.22.3.2
C20-12	Letter dated December 28, 2004 regarding load forecast evidence from the Vancouver Island Energy Corporation
C20-13	Letter dated December 29, 2004 requesting an Order requiring BC Hydro to answer GSXCCC Information Request Nos. 1.22.3.1, 1.22.3.2 and 1.16.2
C20-14	Information Request No. 2 dated December 30, 2004 from William J. Andrews on behalf of the GSX Concerned Citizens Coalition and the BC Sustainable Energy Association
C20-15	Letter dated January 4, 2005 requesting extension of the deadline for GSX Concerned Citizens Coalition and BC Sustainable Energy Association to file Intervenor evidence
C20-16	Letter dated January 4, 2005 regarding the JIESC’s December 16, 2004 application for reconsideration
C20-17	Letter dated January 4, 2005 responding to BC Hydro's response to the GSX Concerned Citizens Coalition and the BC Sustainable Energy Association’s letters of December 23, 29 and 30, 2004
C20-18	Letter dated January 5, 2005 regarding the application for an Order (Exhibit C20-13) and the application for filing extension (Exhibit C20-15)
C20-19	Letter dated January 6, 2005 withdrawing application for an Order
C20-20	Letter dated January 6, 2005 providing the resumé and evidence of Dr. Mark Jaccard
C20-21	Evidence and Resume of Mr. Steve Miller dated January 6, 2005
C20-22	Letter dated January 8, 2005 regarding January 6, 2005 decision letter (Exhibit A-21)
C20-23	Information Request to NorskeCanada dated January 10, 2005
C20-24	Information Request to Duke Point Power Limited Partnership dated January 10, 2005

Exhibit No.	Description
C20-25	Information Request to British Columbia Transmission Corporation dated January 10, 2005
C20-26	Letter dated January 11, 2005 regarding the intent of GSX Concerned Citizens Coalition to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
C20-27	Letter dated January 12, 2005 advising that the Society Promoting Environmental Conservation has joined its intervention with the GSX Concerned Citizens Coalition and BC Sustainable Energy Association (BC Sea)
C20-28	Letter dated January 12, 2005 regarding procedural matters
C20-29	Letter dated January 14, 2005 request for reconsideration on behalf of the GSX Concerned Citizens Coalition
C20-30	Letter dated January 14, 2005 requesting admission of evidence from the VIGP proceeding
C20-31	Response dated January 17, 2005 to BC Hydro Information Request No. 1
C20-32	Response dated January 17, 2005 to Commission Information Request No. 1
C20-33	Vancouver Island Energy Corporation Revised Response dated June 12, 2003 to British Columbia Utilities Commission Staff Information Request No. 2.26.6 dated May 2, 2003 filed in the Commission proceeding on the Vancouver Island Energy Corporation Application for a Certificate of Public Convenience and Necessity for the Vancouver Island Generation Project
C20-34	Letter dated January 21, 2005 replying to submission from counsel for BC Hydro (Exhibit B-66) and counsel for Duke Point Power (Exhibit C17-15)
C20-35	Letter dated January 23, 2005 making application for an order that the Commission Panel disqualify itself from this proceeding
C20-36	"Consistency of Population and Employment Forecasts in the BC Hydro December 2004 Load Forecast, Steve Miller and Associates, January 24, 2005"
C20-37	"Revised Load and Supply Gap Forecast, Steve Miller and Associates, January 24, 2005"

Exhibit No.	**Description**
C21-1	**ELK VALLEY COAL CORPORATION** – Notice of Intervention dated November 26, 2004 from J.D.V. Newlands
C22-1	**MCKECHNIE, BOB** – Notice of Intervention dated November 25, 2004
C22-2	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C22-3	Letter dated December 17, 2004 providing Mr. McKechnie's comments for the Pre-hearing Conference on Exhibit B-8
C22-4	E-mail dated December 22, 2004 regarding Mr. McKechnie's submission to the Pre-hearing Conference of December 22, 2004
C22-5	Letter dated January 4, 2004 (5) regarding the reconsideration issues
C22-6	Letter dated January 6, 2005 regarding inability to submit evidence
C22-7	Letter dated January 19, 2005 commenting on the direction of the Commission's hearing process
C22-8	Letter dated January 25, 2005 regarding Exhibit C20-35
C23-1	**SEA BREEZE POWER CORP.** – Notice of Intervention dated November 25, 2004 from Tony Duggleby
C23-2	Letter dated December 1, 2004 filing documents in support of Mr. Duggleby's oral presentation at the November 29, 2004 Procedural Conference
C23-3	Information Request No. 1 dated December 8, 2004
C23-4	Letter dated December 17, 2004 commenting on BC Hydro's December 14, 2004 letter (Exhibit B-8)
C23-5	Letter dated January 4, 2005 regarding the reconsideration application
C23-6	Evidence dated January 6, 2005 from Sea Breeze Pacific Regional Transmission System Inc.
C23-7	Letter and evidence dated January 17, 2004 (2005)

Exhibit No.	Description
C24-1	**HOWE SOUND PULP AND PAPER LIMITED PARTNERSHIP** – Notice of Intervention dated November 23, 2004 from Pierre G. Lamarche
C25-1	**POST CARBON INSTITUTE** – Notice of Intervention dated November 26, 2004 from Julian Darley
C26-1	**HAGUE, JOHN** – Notice of Intervention dated November 26, 2004
C26-2	E-mail dated December 6, 2004 commenting on the Commission's proposed public hearing process
C26-3	E-mail dated December 14, 2004 commenting on the Call for Tenders process
C26-4	E-mail dated January 11, 2005 regarding quote from Dr. Mark Jaccard
C26-5	E-mail dated January 15, 2005 with comments on Town Hall Meeting evidence
C26-6	Letter dated January 19, 2005 agreeing with Mr. McKechnie and providing further comment on Bill Andrews' Reconsideration Motion (Exhibit C20-29)
C26-7	E-mail dated January 22, 2005 forwarding a Letter of Comment dated January 18, 2005 from Adrian Carr, Leader of the Green Party of BC (Exhibit E-273)
C26-8	Letter dated January 25, 2005 regarding Exhibit C20-35
C26-9	E-mail dated January 27, 2005 commenting on Commission Letter No. L-8-05
C27-1	**CONSTANTINE, TEXAS JOE** – Notice of Intervention dated November 25, 2004
C27-2	Withdrawal of Intervention dated December 10, 2004
C28-1	**HUNTER, M., MLA NANAIMO** – Notice of Intervention dated November 26, 2004
C29-1	**GROOT, KEES DR.** – Notice of Intervention dated November 26, 2004

Exhibit No.	Description
C30-1	**GABRIOLA ISLAND RATEPAYERS AND RESIDENTS ASSOCIATION** – Notice of Intervention dated November 25, 2004 from J. Randy Young, President
C30-2	Information Requests – Round 1 dated December 7, 2004
C30-3	Letter dated December 19, 2004 commenting on the December 17, 2004 Pre-hearing Conference on Exhibit B-8
C30-4	Letter dated December 24, 2004 regarding filing of written evidence after public meeting of January 14, 2004
C30-5	Letter dated December 19, 2004 supporting the JIESC reconsideration application
C30-6	Letter dated January 6, 2005 regarding written evidence
C30-7	E-mail dated January 11, 2005 with comments from Randy Young, President of the Gabriola Island Ratepayers and Residents Association
C30-8	Written Arguments dated January 16, 2005
C30-9	Letter dated January 19, 2005 providing written comments addressing the cost/benefit of the Duke Point Power Plant to the ratepayers of Gabriola Island and other rural residents
C30-10	Email dated January 19, 2005 regarding missed cross-examination opportunities and oral final argument procedures
C31-1	**REGIONAL DISTRICT OF MOUNT WADDINGTON** – Notice of Intervention dated November 26, 2004 from Bill Shephard, Chair
C31-2	Briefing Note dated November 29, 2004
C32-1	**COMMERCIAL ENERGY CONSUMERS** – Notice of Intervention dated November 26, 2004 from Penny Cochrane, Willis Energy Services Ltd.
C32-2	Letter dated January 4, 2005 supporting the JIESC's reconsideration application
C32-3	Letter and evidence dated January 6, 2005 from the Commercial Energy Consumers of BC
C32-4	Letter dated January 12, 2005 commenting on procedural matters

Exhibit No.	**Description**
C32-5	Letter and responses dated January 18, 2005 to Commission Information Request No. 1
C32-6	Letter and responses dated January 18, 2005 to BC Hydro Information Request No. 1
C32-7	Letter dated January 19, 2005 supporting the GSXCCC et. al request for a reconsideration of the limitation set on intervenors regarding their cross-examination of the applicant's witnesses and others in these proceedings
C32-8	Commercial Energy Consumers' Addendum to Testimony
C33-1	**SHADYBROOK FARM** – Notice of Intervention dated November 28, 2004 from Steve Miller
C33-2	E-mail dated December 14, 2004 providing comments on BC Hydro's December 14, 2004 letter (Exhibit B-8)
C33-3	Letter dated December 15, 2004 requesting the deadline for Intervenor Evidence be amended
C33-4	E-mail dated December 17, 2004 commenting on BC Hydro's December 14, 2004 letter (Exhibit B-8)
C33-5	Letter of Comment dated December 17, 2004 regarding BC Hydro's request for relief from the obligation of answering many of the Information Requests posed by BCUC staff and Intervenors
C33-6	E-mail dated December 21, 2004 regarding the Pre-Hearing Conference on December 22, 2004
C33-7	E-mail dated January 11, 2005 regarding the intent of Shadybrook Farm to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
C33-8	Letter dated January 12, 2005 regarding procedural issues
C33-9	Letter dated January 19, 2005 endorsing the GSXCCC et. al request for a reconsideration of the limitation set on intervenors regarding their cross-examination of the applicant's witnesses and others in these proceedings

Exhibit No.	**Description**
C34-1	**SOCIETY PROMOTING ENVIRONMENTAL CONSERVATION** – Notice of Intervention dated November 26, 2004 from Norman Abbey
C34-2	Letter dated January 10, 2005 advising that they are joining with the GSX Concerned Citizens Coalition and will be represented by the same counsel
C35-1	**ERKILETIAN, JIM** – Notice of Intervention received November 29, 2004
C36-1	**MCLENNAN, MÀIRI** – Notice of Intervention dated November 25, 2004
C36-2	Information Request No. 1 dated December 8, 2004 to British Columbia Hydro and Power Authority
C36-3	Letter dated December 17, 2004 commenting on the Pre-hearing Conference process regarding Exhibit B-8 (BC Hydro's December 14, 2004 letter)
C36-4	Letter dated December 22, 2004 regarding EPA Review Process and Pre-Hearing Conference of December 22, 2004
C36-5	Letter dated January 3, 2005 requesting clarification from BC Hydro regarding their response to Intervenor's Information Request No. 1 (attached second Information Request referenced in letter is Exhibit C36-6)
C36-6	Information Request No. 2 dated January 3, 2005
C36-7	Letter dated January 4, 2005 supporting the application made on behalf of the JIESC for reconsideration
C36-8	Letter dated January 5, 2005 requesting extension for filing
C36-9	Letter dated January 5, 2005 expressing concerns regarding the review process
C36-10	Letter and evidence dated January 6, 2005 from Màiri McLennan
C36-11	Letter dated January 11, 2005 regarding the intent of Màiri McLennan to rely on the British Columbia Transmission Corporation December 23, 2004 filing of its Evaluation of the NorskeCanada Demand Management proposal
C36-12	Letter dated January 12, 2005 regarding procedural issues
C36-13	Letter and submission dated January 19, 2005

Exhibit No.	Description
C36-14	Letter dated January 19, 2005 to Mr. Chris Sanderson, BC Hydro Counsel, regarding Information Request Supplementary Responses
C36-15	Letter dated January 25, 2005 regarding Exhibit C20-35
C37-1	**ANDERSEN, ERIK** – Notice of Intervention dated November 26, 2004
C37-2	E-mail dated December 6, 2004 requesting assistance in locating additional information and reports regarding BC Hydro
C37-3	E-mail dated December 22, 2004 regarding Mr. Andersen’s written evidence
C37-4	E-mail dated January 12, 2005 regarding final argument by this Intervenor
C37-5	E-mail dated January 20, 2005 replying to John Hague’s comments on Bill Andrews' Reconsideration Motion (Exhibit C20-29)
C37-6	E-mail dated January 22, 2005 regarding time limiting of witnesses
C37-7	E-mail dated January 24, 2005 joining in support of an action of Mr. Andrews (Exhibit C20-35)
C37-8	Letter dated January 24, 2005 regarding Exhibit No. C20-35
C38-1	**MALCOLMSON, SHEILA, GABRIOLA ISLAND LOCAL TRUSTEE** – Notice of Intervention dated November 26, 2004
C38-2	Letter dated January 25, 2005 regarding Exhibit No. C20-35
C39-1	**VANPORT STERILIZERS INC.** – Notice of Intervention dated December 8, 2004 from Richard Tennant
C39-2	Letter dated December 17, 2004 commenting on BC Hydro’s December 14, 2004 letter (Exhibit B-8)
C39-3	Letter dated December 22, 2004 requesting that the Commission order BC Hydro to formally acknowledge their exhibit and to respond to their Information Request
C39-4	Letter dated January 7, 2005 appealing Commission Order No. G-119-04
C39-5	Letter dated January 21, 2005 regarding reply to Exhibit A-35 for reconsideration of Commission Order No. G-119-04

Exhibit No.	Description
Interested Party Documents	
D-1	Letter dated November 20, 2004 from N. Moysa requesting Interested Party status
D-2	Letter dated November 23, 2004 from Carol and Stewart Boyce requesting Interested Party status
D-3	E-mail dated November 23, 2004 from Emily Carrington requesting Interested Party status
D-4	E-mail dated November 22, 2004 from Roger McLaughlin, Ministry of Energy and Mines requesting Interested Party status
D-4A	Email dated November 26, 2004 responding to Mr. Mike Hunter’s (MLA Nanaimo) e-mail dated November 26, 2004 (Exhibit C28-1)
D-5	Web Registration dated November 24, 2004 from Ben Hyman requesting Interested Party status
D-6	E-mail dated November 24, 2004 from Terrence R. Hanna requesting Interested Party status
D-7	E-mail dated November 23, 2004 from Albert J. Reed, P.Eng., BASc, MASc, M.Eng. requesting Interested Party status
D-8	E-mail dated November 25, 2004 from Howard Stiff requesting Interested Party status
D-9	Letter received November 26, 2005 from Brenda Jager requesting Interested Party status
D-10	Web Registration dated November 26, 2004 from Susanne Shaw requesting Interested Party status
D-11	Letter received November 29, 2004 from Christy Wilson requesting Interested Party status
D-12	E-mail dated November 26, 2004 from Diane Brown requesting Interested Party status
D-13	E-mail dated November 26, 2004 from Nicki Westarp requesting Interested Party status
D-14	E-mail dated November 26, 2004 from John Volkovskis requesting Interested Party status

Exhibit No.	Description
D-15	E-mail dated November 26, 2004 from Glenn Harris requesting Interested Party status
D-16	E-mail dated November 26, 2004 from Judith Graham requesting Interested Party status
D-17	E-mail dated November 26, 2004 from Neal Brown requesting Interested Party status
D-18	E-mail dated November 26, 2004 from Jack and Joanne Schick requesting Interested Party status
D-19	E-mail dated November 25, 2004 from Robert and Mary Jane Derksen requesting Interested Party status
D-20	Web Registration received December 20, 2004 from Kristin Miller, Positive Energy Quilters requesting Interested Party status
D-21	Letter dated December 16, 2004 from Betsy Nuse requesting Interested Party status
D-22	Web Registration received December 22, 2004 from Don Skerik requesting Interested Party status
D-23	Web Registration received January 10, 2005 from Miriam Trevis requesting Interested Party status
D-24	Web Registration received January 10, 2005 from Cori Lynn Carlson, Greater Nanaimo Chamber of Commerce, requesting Interested Party status
D-25	Web Registration received January 12, 2005 from Geza Vamos requesting Interested Party status

Exhibit No.	Description

Letters of Comment

E-1 Form Letter of Comment #1 from the following:

- Victor Villeneuve
- Barbara LeBrasseur
- Jurgen Goering

E-2 Form Letter of Comment #2 received from the following:

- John and Betty Frame
- L. Pruthman
- K. Kozlowski
- Michelle Mcculloch
- Marguerite Frame
- Mildred Hofmann
- M. Stevens
- Valerie Varn
- Union Bay Resident
- Gordon Hodges
- Diane Frame
- Jeri-Lynn Davies
- Sharon Gussey
- Colleen Robson
- Donald Robson
- C. Sellers
- Rob Watt

E-3 Form Letter of Comment #3 received from the following:

- K. Lange
- Brian Pitt
- A. Guss
- McPherson
- Gord Guss
- Richard Calen
- K.M. Young
- S. Rose
- Pat Buzet

E-4 Form Letter of Comment #4 received from the following:

- Ted Pinlait
- Jim Penilott
- Chelsey Penilott
- Trudy Annand
- Ina Thornton
- Bryce Mann
- Brendan Mann
- Tim Wood
- Chantal Smith
- Kyla Marie
- Bill Coyne
- Terry Reeve
- Monica Prosser
- Wily Tochinski

E-5 Letter of Comment dated November 9, 2004 from Arlene Fehr

E-6 Letter of Comment dated November 9, 2004 from Trudy Annand

Exhibit No.	Description
E-7	Letter of Comment received November 12, 2004 from Kathy Peace
E-8	Letter of Comment received November 15, 2004 from John Rozen, The Ridge Neighbourhood Pub
E-9	Letter of Comment dated November 15, 2004 from Wayne Bergquist
E-10	Letter of Comment received November 15, 2004 from a Gold River Resident
E-11	Letter of Comment dated November 19, 2004 from Valerie Walsh
E-12	Letter of Comment dated November 19, 2004 from the Royal Canadian Legion (Branch 270) Gold River
E-13	Letter of Comment dated November 6, 2004 from Mary Rose Letter of Comment dated November 25, 2004 from Mary Rose
E-14	Letter of Comment dated November 17, 2004 from Kristin Miller Letter of Comment No. 2 dated January 10, 2005 and CD from Kristin Miller – note that as the CD is a Powerpoint Presentation from The Positive Energy Quilts and cannot be posted to our website, a copy will be made available for viewing in the Resource Room at the Hearing
E-15	Letter of Comment received November 19, 2004 from John Ebell
E-16	Form Letter of Comment received November 15, 2004 from the following: • Kelly Ballard • Craig Anderson
E-17	Letter of Comment received November 10, 2004 from Brian D. Tutty
E-18	Letter of Comment received November 15, 2004 from Alison M. Pringle
E-19	Letter of Comment received November 15, 2004 from Robert Cooper
E-20	Letter of Comment dated November 16, 2004 from Ian Cuthbert
E-21	Letter of Comment dated November 19, 2004 from Liz Fox
E-22	Letter of Comment dated November 21, 2004 from Elizabeth Lorenz
E-23	Letter of Comment dated November 22, 2004 from Valerie Hennell
E-24	Letter of Comment dated November 22, 2004 from Trish Moon

Exhibit No.	Description
E-25	Letter of Comment dated November 22, 2004 from Terrence R. Hanna
E-26	Letter of Comment dated November 23, 2004 from the Nanaimo Citizen's Organizing Committee (Cathy Booler)
E-27	Letter of Comment dated November 23, 2004 from the Georgia Strait Alliance (Christianne Wilhelmson)
E-28	Letter of Comment dated November 23, 2004 from Hans Kratz, Chair, Parksville/Qualicum KAIROS
E-29	Letter of Comment dated November 23, 2004 from Ken Capon
E-30	Letter of Comment dated November 23, 3004 from Johan de Vaal, P. Eng.
E-31	Letter of Comment dated November 23, 2004 from Jack Moss Letter of Comment dated December 17, 2004 from Jack Moss
E-32	Letter of Comment dated November 23, 2004 from Jacinthe B. Eastick
E-33	Letter of Comment dated November 23, 2004 from Muriel Boulton
E-34	Letter of Comment dated November 23, 2004 from Donalda
E-35	Letter of Comment dated November 23, 2004 from Brenda Purcell
E-36	Letter of Comment dated November 23, 2004 from John Gambrill
E-37	Letter of Comment dated November 23, 2004 from Dianne Ackerman
E-38	Letter of Comment dated November 23, 2004 from Chris Bowers
E-39	Letter of Comment dated November 23, 2004 from Wayne Schneider
E-40	Letter of Comment dated November 23, 2004 from Joan Greaves
E-41	Letter of Comment dated November 23, 2004 from Hans van Kessel
E-42	Letter of Comment dated November 23, 2004 from Oscar Reeves
E-43	Letter of Comment dated November 23, 2004 from Earl St. Denis, Ph.D. P.Eng., Pearse Western Consultants Ltd.
E-44	Letter of Comment dated November 23, 2004 from Emily Carrington
E-45	Letter of Comment dated November 23, 2004 from Fred Apstein

Exhibit No.	Description
E-46	Letter of Comment dated November 22, 2004 from A.D. Fisher
	Letter of Comment dated December 16, 2004 from A.D. Fisher regarding BC Hydro’s December 14, 2004 letter (Exhibit B-8)
E-47	Letter of Comment dated November 24, 2004 from Pamela Ponic, Ph.D (C)
E-48	Letter of Comment dated November 24, 2004 from Dawn & Joe Burnett
E-49	Letter of Comment dated November 24, 2004 from Paul Grignon
E-50	Letter of Comment dated November 16, 2004 from Kathy Peace
E-51	Letter of Comment dated November 23, 2004 from Alan Wilson, Editor, WaveLength Magazine
E-52	Letters of Comment dated November 23 and 25, 2004 from Ben Hyman
E-53	Letter of Comment dated November 23, 2004 from Lynette Van Der Schoot
E-54	Letter of Comment dated November 23, 2004 from Darlene Mace
E-55	Letter of Comment dated November 23, 2004 from Bob Bossin
E-56	Letter of Comment dated November 24, 2004 from Ian Talbot
E-57	Letter of Comment dated November 24, 2004 from Patricia Knowles
E-58	Letter of Comment dated November 24, 2004 from John McKay
E-59	Letter of Comment dated November 23, 2004 from Roger Middleton
E-60	Letter of Comment dated November 23, 2004 from Susan Sharp and George A. (Tony) Sharp
E-61	Letter of Comment dated November 23, 2004 from Jennifer Nash
E-62	Letter of Comment dated November 25, 2004 from François Cormier
E-63	Letter of Comment dated November 25, 2004 from Geoff Yendole
E-64	E-mail dated November 30, 2004 from Art Lee supporting the proposed project
E-65	Letter of Comment dated November 28, 2004 from Mary Gillis

Exhibit No.	Description
E-66	Letter of Comment dated November 30, 2004 from Sue Wheeler
E-67	Letter of Comment dated December 1, 2004 from Janice Lee Power
E-68	November 29, 2004 response to Arlene Fehr from Premier Gordon Campbell
E-69	November 29, 2004 response to Kathy Pearce from Premier Gordon Campbell
E-70	Letter of Comment dated November 26, 2004 from Janice Johnson and Z. Dmytruk
E-71	Letter of Comment dated November 25, 2004 from Constance Neaga Letter of Comment#2 dated November 26, 2004 from Constance Neaga
E-72	Letter of Comment dated November 25, 2004 from Odette Laramee
E-73	Letter of Comment dated November 25, 2004 from Tim Gambrill
E-74	Letter of Comment dated November 25, 2004 from Linnet Kartar
E-75	Letter of Comment dated November 26, 2004 from Terry, Bob and Jeremy Tolmie
E-76	Letter of Comment dated November 25, 2004 from Shirley Petersen
E-77	Letter of Comment dated November 26, 2004 from Judith Roux
	Letter of Comment No. 2 dated January 14, 2005 from Judith Roux
E-78	Letter of Comment dated December 13, 2004 from Tamara Cowan & Kevin Smith
E-79	Letter of Comment dated November 26, 2004 from Jacquie Howardson
E-80-	Letter of Comment dated November 26, 2004 from Kim LeDuc
E-81	Letter of Comment dated November 26, 2004 from Susan McManus
E-82	Letter of Comment dated November 22, 2004 from Rick Scott
E-83	Letter of Comment received November 26, 2004 from Maya Carson
E-84	Letter of Comment dated November 25, 2004 from Randy Ravel
E-85	Letter of Comment dated November 20, 2004 from Dr. G.F. Hartman

Exhibit No.	Description
E-86	Letter of Comment received November 25, 2004 from Ann and Peter Kloosterboer
E-87	Form Letter of Comment dated November 9, 2004 from the following:

- Lee Smith
- Phin Last
- Alex Gineth
- Marion Last
- Angela Smith
- Roslyn Yateman
- Kodi Hutchinson
- Miranda Last
- Chris Hutchinson
- Gold River Resident

E-88 Form Letter of Comment dated November 24, 2004 from the following:

- Joanne Martel
- John Pepau
- Shaina Pepau
- Merissa Pepau
- Branden Pepau
- Cheryl Riddell
- Doug Knowliss
- Julie Wilson
- Reily Wilson
- Melissa Wilson
- Grant Foster
- Larry Rose
- Nicole Baron
- Robert Baron
- Corrie Baron
- Emily Woodruff
- Patricia McDougall
- Jane M. Lum
- William Coyne
- Janet Coyne
- Carol Young
- Phillip Loni
- Anita Rose
- Bonnie Wheatley
- D. Goernert
- Sandra Rose
- Barrie McLennan
- Todd Gedlaman
- Grace Walker
- Brooke White
- Pat Cruickshank
- Bonnie Beggs
- Joanne White
- John Rozek
- Larry Rose
- Harry Curts
- Lori Wilson
- Alex Gueth
- Tim Woods
- Brendan Mann
- Bryce Mann
- Patrick Baron
- Laura Baron
- V. Cruickshank
- Donna Gedlaman
- Judy McLean
- William Woodruff
- Allan Woodruff
- Sharon Chomeczko
- Logan Rose
- Taylor Rose
- Carli Rose
- Sydni Rose
- T. Robertson
- Craig Steeds
- Debbie Steeds
- Erika Rumpel
- Laura Ramirez
- Kathy Peace
- E. Townsend

Exhibit No.	Description
	• Herman White • Linda Hooper • Chris Kuhn • Vivi Rumpel • Lesley White • Amber Lewis
E-89	Letter of Comment received December 8, 2004 from Jesse Hohert
E-90	Letter of Comment received December 6, 2004 from John G. Smith
E-91	Letter of Comment dated December 6, 2004 from Ria Bos
E-92	Letter of Comment dated December 10, 2004 from Marion Waters
E-93	December 10, 2004 response to Craig Anderson from the Honourable Richard Neufeld
E-94	Letter of Comment dated December 9, 2004 from Mayor Lynn D. Nash, District of Campbell River
E-95	Petition entitled "Duke Point Power: A Public Petition for a Procedural Conference in Nanaimo" received December 20, 2004
E-96	Letter of Comment dated December 9, 2004 from Mayor Gerry Furney, Town of Port McNeill
	Letter of Comment No. 2 dated January 5, 2005 from Mayor Gerry Furney, Town of Port McNeill
	Letter of Comment No. 3 dated March 24, 2004 to Pristine Power Inc. from Mayor Gerry Furney, Town of Port McNeill
E-97	Letter of Comment dated December 29, 2004 from John Volkovskis
	Letter of Comment No. 2 dated December 29, 2004 from John Volkovskis
	Letter of Comment No. 3 dated December 30, 2004 from John Volkovskis
	Letter of Comment No. 4 dated January 13, 2004 from John Volkovskis
E-98	Letter of Comment dated December 19, 2004 from Kathleen Woodley
E-99	Letter of Comment dated December 31, 2004 from Jorden Leighton
E-100	Letter of Comment dated January 1, 2005 from Hendrik de Pagter and Jennifer Sagar
E-101	Letter of Comment dated January 1, 2005 from John Alton

Exhibit No.	**Description**
E-102	Letter of Comment dated January 1, 2005 from Eileen deVerteuil
E-103	Letter of Comment dated January 2, 2005 from Michael Mundhenk
E-104	Letter of Comment dated January 2, 2005 from John Scull
E-105	Letter of Comment dated January 2, 2005 from Lee Larkin
E-106	Letter of Comment dated January 2, 2005 from Alan Merson
E-107	Letter of Comment dated January 3, 2005 from Frances Hill
E-108	Letter of Comment dated January 3, 2005 from Glenn Buchanan
E-109	Letter of Comment dated January 3, 2005 from Jennifer Nash
E-110	Letter of Comment dated January 3, 2005 from John Bowers
E-111	Letter of Comment dated January 3, 2005 from Ray Myrtle
E-112	Letter of Comment dated January 3, 2005 from Beth Dunlop
E-113	Letter of Comment dated January 4, 2005 from A concerned citizen, Roo
E-114	Letter of Comment dated January 4, 2005 from Michael Crouteau
E-115	Letter of Comment dated January 4, 2005 from Susan Gage
E-116	Letter of Comment dated January 5, 2005 from Marcia Stewart
E-117	Letter of Comment dated January 5, 2005 Tania Harrington
E-118	Letter of Comment dated January 5, 2005 Richard Zwolinski
E-119	Letter of Comment dated December 31, 2004 from Peter Spurr
E-120	Letter of Comment dated January 5, 2005 from Donan R. Doyle
E-121	Letter of Comment dated January 5, 2005 from Fasma Lacroix
E-122	Letter of Comment dated January 5, 2005 from EPCOR
	Letter of Comment No. 2 dated January 12, 2005 from EPCOR
E-123	Letter of Comment dated January 6, 2005 from CALPINE
E-124	Letter of Comment dated January 5, 2005 from Arno Schortinghuis

Exhibit No.	Description
E-125	Letter of Comment dated January 7, 2005 from Sherri Hohert
E-126	Letter of Comment dated January 6, 2005 from Christy Gain
E-127	Letter of Comment dated January 6, 2005 from Bo Filter
E-128	Letter of Comment dated January 5, 2005 from Garry Davey
E-129	Letter of Comment dated January 5, 2005 from Suzanne Murray
E-130	Letter of Comment dated January 5, 2005 from Kelly Aitken
E-131	Letter of Comment dated January 7, 2005 from Scott Pederson
E-132	Letter of Comment dated January 7, 2005 from Chris Bowers
E-133	Letter of Comment dated January 4, 2005 from Sharon Rogalsky
E-134	Letter of Comment dated January 7, 2005 from Rev. John Guy
E-135	Letter of Comment dated January 7, 2005 from Brooke Watson
E-136	Letter of Comment dated January 10, 2005 from Elvira Aloka Caduff
E-137	Letter of Comment dated January 9, 2005 from TW Heidrick
E-138	Letter of Comment dated January 4, 2005 from Earl St. Denis
E-139	Letter of Comment dated January 3, 2005 from Marilyn Horsdal
E-140	Letter of Comment dated December 29, 2004 from Gary Korpan, Mayor - City of Nanaimo
E-141	Letter of Comment dated January 6, 2005 from Bill Alexander
E-142	Letter of Comment dated January 8, 2005 from Don and Pam Munroe
E-143	Letter of Comment dated January 8, 2005 from Ray Grigg
E-144	Letter of Comment dated January 8, 2005 from Bill Wheeler
E-145	Letter of Comment dated January 8, 2005 from Roger Colwill
E-146	Letter of Comment dated January 9, 2005 from Jan Engstrom
E-147	Letter of Comment dated January 9, 2005 from Fred Bevis

Exhibit No.	Description
E-148	Letter of Comment dated January 9, 2005 from Pamela Gambrill
E-149	Letter of Comment dated January 9, 2005 from Geordie Peace
E-150	Letter of Comment dated January 9, 2005 from Donna Dixon
E-151	Letter of Comment dated January 10, 2005 from Chris Hilliar
E-152	Letter of Comment dated January 8, 2005 from Bill McCaugherty
E-153	Letter of Comment dated January 8, 2005 from Annabelle Cameron
E-154	Letter of Comment dated January 4, 2005 from John G. Smith and Susan M. Smith
E-155	Letter of Comment dated January 10, 2005 from Margaret Fear
E-156	Letter of Comment dated January 5, 2005 from Richard and Barbara Porter
E-157	Letter of Comment dated January 6, 2005 from W. Bruce Cooper and Lois M. Cooper
E-158	Letter of Comment dated January 7, 2005 from Jean Lamond
E-159	Letter of Comment dated January 7, 2005 from Katherine McDonnell
E-160	Letter of Comment dated January 6, 2005 from Virginia Newman
E-161	Letter of Comment dated January 10, 2005 from Faye Mogensen
	Letter of Comment No. 2 dated January 7, 2005 from Faye E Mogensen
E-162	Letter of Comment dated January 9, 2005 from Antoinette Spoor
E-163	Letter of Comment dated January 9, 2005 from Lynn Daniel
E-164	Letter of Comment dated January 10, 2005 from Robyn Quaintance
E-165	Letter of Comment dated January 10, 2005 from Anne Wilson
E-166	Letter of Comment dated January 10, 2005 from Andrew Cameron
E-167	Letter of Comment dated January 10, 2005 from Phil Folkard
E-168	Letter of Comment dated January 10, 2005 from Roz Powell
E-169	Letter of Comment dated January 10, 2005 from Jayson Biggins

Exhibit No.	Description
E-170	Letter of Comment dated January 10, 2005 from Anna Purcell
E-171	Letter of Comment dated January 10, 2005 from Drew Cooper, Pacific Sport-Vancouver Island
E-172	Letter of Comment dated January 10, 2005 from Ken Mac Aulay
E-173	Letter of Comment dated January 10, 2005 from Liz Fox
E-174	Letter of Comment dated January 10, 2005 from Karen Carlyle
E-175	Letter of Comment dated January 10, 2005 from Bernice Levitz Packford
E-176	Letter of Comment dated January 10, 2005 from Pat Tiedemann
E-177	Letter of Comment dated January 10, 2005 from Laura Moore
E-178	Letter of Comment dated January 10, 2005 from Tsiporah Grignon
E-179	Letter of Comment dated January 10, 2005 from Patty Rangel
E-180	Letter of Comment dated January 10, 2005 from Geoff Senichenko
E-181	Letter of Comment dated January 10, 2005 from D.A. Yamaguchi
E-182	Letter of Comment dated January 10, 2005 from Mary-June Pettyfer
E-183	Letter of Comment dated January 11, 2005 from Richard Cabell
E-184	Letter of Comment dated January 11,2005 from Bijan K. Basak
E-185	E-mail Letter of Comment dated January 11, 2005 from Patricia Ludwick
	Letter of Comment No. 2 dated January 11, 2005 from Patricia Ludwick
E-186	Letter of Comment dated January 11, 2005 from Drew Allan
E-187	Letter of Comment dated January 11, 2005 from Matthew Craig
E-188	Letter of Comment dated January 11, 2005 from Moni Murray, Nanaimo International Hostel
E-189	Letter of Comment dated January 11, 2005 Bob and Joy Newall
E-190	Letter of Comment dated January 11, 2005 from Patrick and Jane Fawkes
E-191	Letter of Comment dated January 11, 2005 from W.K. Potter

Exhibit No.	Description
E-192	Letter of Comment dated January 14, 2005 from Katherine Muncaster
E-193	Letter of Comment dated January 11, 2005 from Jorden Leighton
E-194	Letter of Comment dated January 11, 2005 from Bob Landell, Avalon Mechanical Consultants Ltd.
E-195	Letter of Comment dated January 5, 2005 from Blaise Salmon
E-196	Letter of Comment dated January 9, 2005 from Elvira Aloka Caduff
E-197	Letter of Comment dated January 11, 2005 from Ron D Brown
	Letter of Comment No. 2 dated January 13, 2005 from Ron Brown
E-198	Letter of Comment dated January 11, 2005 from Jenny Farkas, Councillor, City of Duncan
E-199	Letter of Comment dated January 11, 2005 from Penelope J. Bahr
E-200	Letter of Comment dated January 11, 2005 from Don Cavers
E-201	Letter of Comment dated January 11, 2005 from Jack and Joanne Schick
E-202	Letter of Comment dated January 11, 2005 from Calli O'Brien
E-203	Letter of Comment dated January 11, 2005 from Kees Schaddelee
E-204	Letter of Comment dated January 11, 2005 from Stuart Denholm
E-205	Letter of Comment dated January 11, 2005 from David Kidd
E-206	Letter of Comment dated January 12, 2005 from Don Goodeve
E-207	Letter of Comment dated January 12, 2005 from Dave Pennington
E-208	Letter of Comment dated January 12, 2005 from Sheila Norgate
E-209	Letter of Comment dated January 12, 2005 from Ellen Rainwalker
E-210	Letter of Comment dated January 11, 2005 Jennifer Jan Elsey
E-211	Letter of Comment dated January 12, 2005 Gail Hourigan
E-212	Letter of Comment dated January 13, 2005 Rachel McMillen
E-213	Letter of Comment dated January 12, 2005 Tina J. Taylor

Exhibit No.	Description
E-214	Letter of Comment dated January 12, 2005 Darcy Johnson
E-215	Letter of Comment dated January 12, 2005 Marilyn S. Weland
E-216	Letter of Comment dated January 12, 2005 from Penelope J. Bahr
E-217	Letter of Comment dated January 13, 2005 P. Grout
E-218	Letter of Comment dated January 13, 2005 Nic Rivers
E-219	Letter of Comment dated January 13, 2005 Nadia L.R. Engelstoff
E-220	Letter of Comment dated January 4, 2005 Frank Ney
E-221	Letter of Comment dated January 6, 2006 (5) from Patrick Tiernan
E-222	Letter of Comment dated January 11, 2005 from Ruth McLeod
E-223	Letter of Comment dated January 10, 2005 from Beth Gibson
E-224	Letter of Comment dated January 10,2 005 from Brian Thacker
E-225	Letter of Comment dated January 10, 2005 from Rick Thurmeier
E-226	Letter of Comment dated January 9, 2005 from a Vancouver Island Resident
E-227	Letter of Comment dated January 7, 2005 from Edward D. MacKenzie and Jean K. MacKenzie
E-228	Letter of Comment dated January 9, 2005 from Bill Heidrick
E-229	Letter of Comment dated January 13, 2005 from V. Dartnell and H. Lawson
E-230	Letter of Comment dated January 13, 2005 from Charlie Wilson
E-231	Letter of Comment dated January 13, 2005 Margaret W. Dyke
E-232	Letter of Comment dated January 13, 2005 from Susan South
E-233	Letter of Comment dated January 6, 2005 from Laura Barker
E-234	Letter of Comment dated January 13, 2005 from Carol and Stewart Boyce
E-235	Letter of Comment dated January 13, 2005 from Regina Wende
E-236	Letter of Comment dated January 13, 2005 from Darryl Receveur

Exhibit No.	Description
E-237	Letter of Comment dated January 13, 2005 from Chris Mott
E-238	Letter of Comment dated January 14, 2005 from Steve Filipovic
E-239	Letter of Comment dated January 14, 2005 from Margaret Johnson
E-240	Letter of Comment dated January 14, 2005 from Sue Solomon
E-241	Written presentation of Ms. Ruth Chase from the January 15, 2005 Town Hall Meeting
E-242	Written presentation of Ms. Sheila Malcolmson from the January 15, 2005 Town Hall Meeting
E-243	Written presentation of Mr. Ian Gartshore from the January 15, 2005 Town Hall Meeting
E-244	Written presentation of Ms. Kristin Miller and slide presentation CD from the January 15, 2005 Town Hall Meeting
E-245	Written presentation of Mr. Norman Abbey from the January 15, 2005 Town Hall Meeting
E-246	Written presentation of Mr. Doug Catley from the January 15, 2005 Town Hall Meeting
E-247	Written presentation of Anthony D. Fisher from the January 15, 2005 Town Hall Meeting
E-248	Graph presentation Entitled “The General Depletion Picture, Oil and Gas Liquids, 2004 Scenario” submitted by William Pearce at the January 15, 2005 Town Hall Meeting
E-249	Written presentation of Jim Erkiletian and words of songs from the January 15, 2005 Town Hall Meeting
E-250	Book “Stormy Weather – 101 Solutions to Global Climate Change”, authored by Guy Dauncey with Patrick Maza from the January 15, 2005 Town Hall Meeting
E-251	Written presentation of Mr. Steve Earle from the January 15, 2005 Town Hall Meeting
E-252	Written presentation of Donnie Richmond-Groot from the January 15, 2005 Town Hall Meeting

Exhibit No.	Description
E-253	Written presentation of Mr. Kees Groot from the January 15, 2005 Town Hall Meeting
E-254	Speaking Notes from Darleen Mace presented at the January 15, 2005 Town Hall Meeting
E-255	Petition from Gold River in support of the Green River Energy Proposal presented at the January 15, 2005 Town Hall Meeting
E-256	Written presentation of Ms. Suzanne Gregory from the January 15, 2005 Town Hall Meeting
E-257	Written presentation of Mr. Iain Cuthbert from the January 15, 2005 Town Hall Meeting
E-258	Written submission of Barbara Jane Godson from the January 15, 2005 Town Hall Meeting
E-259	Written submission of Jim Mitchell from the January 15, 2005 Town Hall Meeting
E-260	Written submission of Mr. John Ebell from the January 15, 2005 Town Hall Meeting
E-261	Written submission of District of Campbell River, as submitted by Morgan Ostler at the January 15, 2005 Town Hall Meeting
E-262	Written Submission of Cedar Women’s Institute and Resolution from the January 15, 2005 Town Hall Meeting
E-263	Written submission of Ms. Linnet Kartar from the January 15, 2005 Town Hall Meeting
E-264	Written submission of Dyane Brown from the January 15, 2005 Town Hall Meeting
E-265	Written submission of Alexandra Hodson from the January 15, 2005 Town Hall Meeting
E-266	Written submission of Howard Stiff from the January 15, 2005 Town Hall Meeting
E-267	Written submission of Vulcan International Thermal Services Inc. and Kenneth MacAulay, as presented by Sean Cullum at the January 15, 2005 Town Hall Meeting

Exhibit No.	Description
E-268	Written presentation of Mr. Gordon Bell from the January 15, 2005 Town Hall Meeting
E-269	Written submission of Ms. Tina Taylor from the January 15, 2005 Town Hall Meeting
E-270	Written submission of Ms. Jacquie Howardson from the January 15, 2005 Town Hall Meeting
E-271	Cards of Comment (13) submitted on January 15, 2005 at the Town Hall Meeting
E-272	Letters of Comment (15) received on January 17, 2005 from the following: Janina Stajic; Sonja Young; Mary Rose; Linda Prowse; Guy Oliver; Peter Johnston; Terry Dyck; Rachel Forbes; Jim Pine; Natalie Cuthbert; Freya Keddie; Don Brown; Monika Murray; Heather Ferguson and Marty Rosa; Peter Ferlow
E-273	Letters of Comment (7) received on January 18, 2005 from the following: Allen Darling; Adriane Carr-Leader of Green Party of BC; Natalie Cuthbert; Joan Baird; Walt Jones; Joan Greaves; Jonathan Berry and Erika
E-274	Letters of Comment (7) received January 19, 2005 from the following: Meghan Haraba; Sue Solomon; Dana Plett; Faith Takishita & Anthony Robertson; Julie Raddysh; John & Tawny Capon; Kristin Miller
E-275	Letter from Office of the Premier received January 19, 2005 responding to Letters of Comment from: Kees Schaddelee; Emily Carrington; Monika Murray; Janice Lee Power; Steven Earle; Don Goodeve; Antoinette Spoor; Lynn Daniel; Jorden Leighton; Brian Grosseth; Arno Schortinghuis; Marcia Stewart; Penelope J. Bahr; Drew Cooper; Liz Fox; Katherine Muncaster; Terry Dyck; Kathie Woodley; Richard and Barbara Porter; Allie Wilson; Dana Plett; John Volkovskis

Exhibit No.	Description

E-276 Letters from Office of the Premier received January 19, 2005 responding to Letters of Comment from the following:

- Sonya Young
- Pamela Gambrill
- Valerie Walsh
- B. Champion
- Kristin Miller

E-277 Response dated January 18, 2005 from John Volkovskis to the Premier

E-278 Letters of Comment received January 21, 2005 from the following:

- Noel Lewis-Watts
- Geza Vamos
- Kristin Miller

E-279 Letter from Office of the Premier received January 21, 2005 responding to Letter of Comment from Faith Takishita and Anthony Robertson

E-280 Letters of Comment received January 21, 2005 from the following:

- William A. Pearce, Q.C.
- Natalie Cuthbert
- Mary Gray
- Audrey E. Graham
- Mayor Harry Most, District of Port Hardy
- Arnold Ranneris, Society of Friends, Peace and Social Concerns Committee
- Meghan Hanrahan (Duplicate – See Exhibit E-274)
- Sue Solomon (Duplicate – See Exhibit E-274)
- Dana Plett (Duplicate – See Exhibit E-274)

E-281 Letters of Comment received January 24, 2005 from the following:

R.T. Wellman; Chris Bullock

Exhibit No.	Description
E-282	Letters of Comment received January 25, 2005 from the following: Wayne Keil; Bill Coyne; Joyce Beaton; Jane Good; Sandie Rose; Barbara Ann McKenney; Donald E. McKenney; Doug Wilson; Terry Muress; Suzanne Trevis; Miriam Trevis; Marion Last; Craig Anderson; Chris White-Councillor, Village of Gold River; Shane Laviolette; Joanne Folkins; Janet Coyne; Barbara Brinkman; Laura Wagstaff; Owen Green; Aleck Spracklin; Coleen Zimmer; John Rozek; Paul Laviolette; Fran Croteau; John McPherson
E-283	Letters of Comment received January 26, 2005 from the following: Alan and Pat Cruickshank; Dawn and Joe Burnett; M. H. Hatch; Amy Newman; William A. Pearce, QC; Group of BC Hydro retirees (note: two pages of a letter from this group were received by regular mail, however, it appears that there should have been a page 3, which did not get included in the mailing); Coben Christianson; Laurie Broadhurst; H.A.C. Stickland
E-284	Letters of Comment received January 28, 2005 from the following: Jan Slakov; Gil Parker
E-285	Letters from Office of the Premier received January 28, 2005 responding to Letters of Comment from the following: R.T. Wellman; Tasma Lacroix; John G. Smith and Susan M. Smith