CALL FOR TENDERS FOR CAPACITY AND ASSOCIATED ENERGY SUPPLY ON VANCOUVER ISLAND ("CFT")

REPORT ON THE CFT PROCESS CONDUCTED BY BC HYDRO

November 19, 2004

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1. Background

BC Hydro has an obligation to serve its customers. BC Hydro takes this obligation to serve very seriously as electricity is an essential service and it meets that obligation by delivering a secure reliable power supply to all its customers at the lowest possible cost. “Not enough” is not an option and BC Hydro plans and operates its electricity system in a way that ensures there is, and will be, enough.

BC Hydro’s obligation to serve its customers means that it plans for new electricity resources in accordance with industry-based integrated system reliability standards. The British Columbia Utilities Commission (“Commission” or “BCUC”) has previously endorsed BC Hydro’s compliance with these standards and also believes that the economic consequences of load shedding, other than in exceptional circumstances, are not acceptable.

A solution to Vancouver Island’s capacity problems has been sought for over 10 years. Every plausible solution has been extensively studied. Through the CFT process, all those with their own ideas of how to provide a solution have been offered the opportunity to come forward and many responded. Reliable supply on Vancouver Island depends on proceeding with the project that has emerged as the winner in this process.

In the mid-1990’s, BC Hydro identified the critical supply issues facing Vancouver Island, in particular the capacity shortfall that is expected to occur primarily as a result of the ageing transmission system through which 80% of the Island’s electricity requirements are delivered. BC Hydro has consistently identified this as a regional supply problem for which new infrastructure is needed, whether in the form of on-Island generation, new transmission from the BC Mainland, or both. In particular, dependable capacity must be in place by 2007 to offset the fact that the high voltage direct current (HVDC) transmission system will no longer be able to reliably supply Vancouver Island from the mainland of the province. Addressing the Vancouver Island reliability problem included seeking proposals for new supply-side and demand-side resources in 1994, pursuant to government policy of the day. This process resulted in the development of the Island Cogeneration Plant (ICP), which became operational in 2002, and culminated in the Vancouver Island Generation Project (“VIGP”) for which BC Hydro was directed to apply to the Commission.

On March 12, 2003, Vancouver Island Energy Corporation (“VIEC”), a wholly owned subsidiary of BC Hydro, applied to the BCUC for a certificate of public convenience and necessity (“CPCN”) for VIGP comprised of a combined-cycle gas turbine (“CCGT”) plant located at Duke

Point near Nanaimo, a connection and upgrade to the existing on-Island electric transmission grid, a short on-Island gas supply pipeline, a water supply line from the existing reservoir at the Harmac pulp mill owned by Pope & Talbot Ltd., and a wastewater line to the existing treatment system. The facility was to be located on an industrial site acquired from Pope & Talbot Ltd. The VIGP plant design incorporated a General Electric 7FA gas turbine to produce 170 MW of electricity, a heat recovery steam generator to generate steam from the turbine exhaust gases, and a steam turbine to produce 95 MW of electricity. The plant was thus expected to generate 265 MW of dependable capacity and to dispatch up to 2,100 GWh of energy per year. Using direct duct firing, VIGP would have capacity of up to 295 MW.

On September 8, 2004, the Commission issued a decision denying VIEC's application on the basis that VIEC had not conclusively established that VIGP was the most cost-effective means of meeting the capacity constraints that BC Hydro foresaw on Vancouver Island (the "VIGP Decision"). The Commission agreed with BC Hydro's conclusion that it would be imprudent to continue to rely on this ageing transmission system even with continued expenditures to maintain and repair it. The Commission accepted that there will be a capacity shortfall on Vancouver Island commencing in the winter of 2007/08 and encouraged BC Hydro to proceed with a Call For Tenders (CFT) to formally elicit new generation projects and to closely follow the schedule set forth in Schedule A as filed in VIEC's Reply Argument on July 25, 2003 (attached as Appendix A to this report).

The Commission recognized that the results of the CFT would provide valuable information to BC Hydro to identify the most cost-effective resource addition for Vancouver Island. Furthermore, the Commission distinguished "most cost effective" from "least cost" on the basis that the former includes consideration of project characteristics such as reliability, dispatchability, timing and location as well as the electricity price while the latter considers only price.[1] The Commission said that: "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."[2]

BC Hydro thereupon embarked on a competitive and transparent CFT process focused on securing dependable capacity by May 2007. As encouraged by the Commission, an integral part of the CFT process adopted was the appointment of an independent reviewer ("IR")

[1] VIGP Decision, p.77.
[2] VIGP Decision, p.77.

charged with monitoring the development and implementation of the CFT and reporting on its fairness and impartiality. PricewaterhouseCoopers ("PwC") was retained to perform this role.

On October 31, 2003, BC Hydro issued the CFT (see Appendix B) in a form that conformed to the approach put forward in the hearing, incorporated the design comments of the IR, and reflected the suggestions received from the Commission in the VIGP Decision. The key elements incorporated into the CFT to reflect the Commission's comments as they relate to the CFT terms outlined in Schedule A are summarized in Table 1 below.

Table 1

Summary of VIGP Decision, BCUC Comments on
Draft BC Hydro CFT and BC Hydro Response

VIGP Decision Issue	BCUC Comments	BC Hydro Response per CFT
Dependable Capacity (Section 9.7)	Calculated VI shortfall at 116 MW but minimum capacity could be 150 MW	Reduced minimum portfolio size from 240 MW to 150 MW
Demand Side Management (Sections 3.3 and 9.7)	No contracted demand reductions should be added to dependable supply	CFT confined to on-Island generation; no DSM options
Evaluation Model (Sections 9.4 and 9.7)	Develop a simplified NPV model limited to on-Island generation costs	Developed a stand-alone NPV model for on-Island generation
Self-Bid Benchmark (Sections 9.4 and 9.7)	Set out the parameters for a CFT Benchmark	Exclude VIGP benchmark from evaluation; use it for comparison purposes upon EPA filing
Independent Reviewer (Section 9.3)	Encouraged BC Hydro to select an IR that would report to a Commissioner	BC Hydro retained PwC as the Independent Reviewer
Sale of VIGP (Section 9.8)	Encouraged BC Hydro to divest VIGP and GSX; willing to expedite approval of CPCN application for VIGP	Retained option for bidders to tender for acquisition of existing VIGP assets.

Consistent with the BCUC's comments, BC Hydro notified potential CFT bidders that it required 150 MW to 300 MW of dependable capacity comprising new on-Island generation using proven technology and capable of being in commercial operation by May 2007. The CFT permitted proponents to tender offers to supply BC Hydro's needs with any resources that met these criteria on a fixed price or gas tolled basis. The gas tolling option was offered on the basis that BC Hydro is in a strong position to cost effectively take on the responsibility for gas supply and effectively mitigate any exposures within its existing portfolio and gas procurement activities. The CFT also allowed proponents to include an offer to acquire BC Hydro's VIGP assets (the "VIGP Election"), consisting primarily of land, a steam turbine and current environmental and other permits necessary to construct a CCGT plant at the site, for a price of $50 million. The CFT appended the draft terms of the Electricity Purchase Agreement (EPA) that successful proponents would be required to sign.

Between October 31, 2003 and March 5, 2004, BC Hydro proceeded with a formal and transparent comment process that resulted in CFT revisions reflecting comments from potential bidders and extensive comments from the BCUC in a January 23, 2004 letter to BC Hydro. This period offered bidders several opportunities to provide comments on both the terms of the CFT as well as the principal agreements. BC Hydro's actions in receiving comments, providing responses and making changes to the CFT and associated agreements were carefully monitored by the IR at each step of the process.

The details of the CFT process employed are provided in the next section of this report.

2. CFT Process and Implementation

2.1 CFT Schedule

In conducting the Vancouver Island CFT, BC Hydro adhered to the following schedule:

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

2.2 Response to CFT Design and Issuance

By mid-November 2003, 23 bidders had registered to participate in the Vancouver Island CFT, including several proponents who made the VIGP Election. On November 23, 2003, a pre-qualification workshop was held for all registered bidders covering the general design and terms of the CFT and requirements for the pre-qualification phase.

During the pre-qualification workshop, registered bidders asked several questions about the CFT process. Responses to these queries were posted on the VICFT website on November 26. Among the questions, was the application of credits for the value of the VIGP development assets in the CFT evaluation process. As per the detailed response to Q&A #118, BC Hydro explained to bidders that the $50 million credit for a VIGP bid reflected the fair market value of

the development assets assuming they were utilized in a successful tender. Similarly, the $20 million credit (later reduced to $14 million) for the VIGP assets reflected the estimated salvage value of the assets assuming no VIGP plant was built. A summary of the credit valuation analysis is provided in Appendix C.

As shown in Appendix C, the steam turbine, land permitting/regulatory approvals and other agreements are valued at BC Hydro's carrying cost (excluding IDC) with no value attributed to the canceled gas turbine. Additionally, BC Hydro places a $18 million fee value on the considerable development work done to date. The $14 million credit for non-VIGP bids is based on the actual cost of the land plus an assumed 50% of the direct cost of the steam turbine.

2.3 Comments from Bidders and Interested Parties

As noted in the CFT schedule shown above, BC Hydro provided numerous opportunities (both verbal and written) for bidders and interested parties to provide comments on the CFT and the preliminary form agreements. On December 1, 2003, BC Hydro received written comments from registered bidders. BC Hydro posted responses to all bidder comments on December 15, 2003 on its website (http://bchydro.com/vicft). A forum for all VIGP intervenors, interested non-bidders and BCUC staff members was held in Nanaimo on December 19, 2003, followed by an evaluation workshop for bidders and BCUC staff on January 6, 2004. Bidders and non-bidders were provided another opportunity to provide comments on the CFT by January 9, 2004. On January 13, 2004, BC Hydro responded to the various comments by issuing a revised CFT and amended preliminary form agreements, all of which were provided to the BCUC along with the written comments/replies received from registered bidders (see Appendix D).

2.4 BCUC Involvement

From the outset of the CFT, BC Hydro encouraged the Commission's input to the CFT design process. On October 23, 2003, BC Hydro put its proposed CFT terms before the Commission in order to introduce as much regulatory certainty as possible and create an active and competitive bidding climate (see Appendix E). In its January 13, 2004 letter to the Commission BC Hydro put the final CFT terms to the Commission including the evaluation criteria and methodology, the related documents, and the CFT schedule (see Appendix D). In its January 23, 2004 response letter to BC Hydro, the BCUC provided non-binding comments on the form of the CFT (see Appendix F).

2.5 Suspension Period and Revised CFT

On January 30, 2004, BC Hydro suspended the CFT process in order to review the impact of the Commission's January 23 letter and to incorporate any required changes with minimal impact on the CFT schedule in a manner that was fair to all participants in the process.

On March 5, 2004, BC Hydro resumed the CFT process with the issuance of Addendum 10 (attached as Appendix G). The deadlines for submission of pre-qualification statements and tenders was extended by 5 to 6 weeks to correspond to the period during which the process was suspended to permit the preparation of a revised CFT in response to the BCUC's comments. Addendum 10 outlined several changes to the CFT (highlighted in Table 2 below) which responded to the comments provided by the Commission in its January 23rd letter.

Table 2

Summary of BCUC January 23rd comments and BC Hydro response as per CFT Addendum 10

Issue	BCUC Comment	BC Hydro Response per CFT Addendum
Scope of the CFT	Encourages BC Hydro to seek approval for projects with an aggregate capacity of at least 150 MW as long as each project is cost-effective, and the aggregate capacity is required to meet Vancouver Island and system load requirements. If the dependable capacity does not exceed 115 MW, then the Commission encourages BC Hydro to accept a cost-effective portfolio with dependable capacity as low as 115 MW before considering other resource additions than on-Island generation	Amended privative clause allowing BC Hydro to select individual Tenders below 150 MW if minimum portfolio size not met or portfolio is not cost-effective
Transmission Deferral Credit	Should not expect Commission Panel to accept the transmission deferral credit	Transmission deferral credit deleted
Staged Addition of Capacity Resources	Portfolio approach with no staging can reasonably be anticipated to be acceptable	QEM unchanged i.e. does not allow staged capacity additions
Sale of VIGP Assets	The CFT design as related to the VIGP assets may not be inconsistent with the VIGP decision; however, the treatment of, and value determination of, the VIGP sunk costs will need to be justified in any application for approval of the project(s) selected by the CFT.	Assigned $50 million credit for portfolios with VIGP assets, representing its fair market value; and the $20 million credit for other portfolios, representing VIGP asset salvage value (later reduced to $14 million).
Gas and Electricity Prices	Should not assume that the Commission Panel will accept that equal weight should be assigned to the results for each of the 5 gas/electricity price scenarios	Removed the 5 price scenarios and adopted one gas price forecast (EIA Reference Case) and 2 corresponding electricity price forecasts
Gas Transportation Costs	Questioned why a bidder should not be able to choose a tolling option for the gas commodity without transportation	Added the "partial tolling/commodity only" option where bidder responsible for providing gas transportation
Electrical Network Upgrade Costs	Accepts in principle that portfolio analysis should include network upgrade costs on VI and that each bidder is treated fairly	Relied on BCTC to provide reasonable costs with fair allocation
Other CFT Issues	Will be concerned if mandatory requirements, information revisions or discretionary judgements are more stringent or less flexible than the minimums that are needed	Amended CFT to provide more flexibility - allowed split bids - relief for failure to obtain permits or achieve 97% availability - fuel supply certainty relaxed
Project(s) Review	Suggested that the time allowed for a BCUC hearing relating to the section 71 application be extended by 30 days	EPA amended to allow for a minimum 90-day period for a BCUC hearing

The summary effect of the VIGP decision and changes to the CFT design in response to the Commission's comments resulted in a Quantitative Evaluation Methodology that favoured projects aggregating at the minimum portfolio size (150 MW) relative to those aggregating at the maximum portfolio size (300 MW).

2.6 Pre-Qualification Submissions

On March 29, 2004, BC Hydro received 14 pre-qualification submissions from registered bidders. As prescribed in the CFT, BC Hydro's Submission Evaluation Committee (SEC) assessed the pre-qualification submissions against financial and technical "Mandatory Criteria" as defined in the CFT. Each bidder was required to demonstrate financial creditworthiness and development experience. Each project was required to provide dependable capacity of at least 25 MW and have commercial operation scheduled by May 1, 2007. The assessment of the Mandatory Criteria was conducted by BC Hydro in conjunction with third party advisors (KPMG and R.W. Beck) with continual oversight by the independent reviewer.

On April 29, 2004, BC Hydro announced that 11 bidders had pre-qualified for the CFT with 22 projects, largely based on natural gas technology, including 6 VIGP projects. A hydroelectric project and a wood waste project were also pre-qualified. The large number of pre-qualified bidders and projects suggested that the CFT was proving to be a competitive process and would yield numerous viable portfolios. Three of the bidders providing pre-qualification submissions were disqualified from further CFT participation due to a failure to meet the Mandatory Criteria. The projects proposed by the disqualified bidders were a coal plant at Campbell River, a wind farm at Knob Hill, and a biomass/coal plant at Beaver Cove. The IR reviewed and confirmed the basis for disqualification.

2.7 Tender Phase

During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities.

On August 13, 2004, BC Hydro received tenders from six pre-qualified bidders and a total of ten proposed projects thereby demonstrating that the CFT had resulted in a healthy competition. These tenders confirmed a legally binding obligation on BC Hydro to complete the process in accordance with the tender documents and to follow the tender selection process included therein, and, on the bidder to enter into an EPA if selected by that process. Following a completeness and conformity review, BC Hydro determined that two of the tenders (with 3 proposed projects) should be rejected due to non-compliance with the CFT requirements. One

bidder failed to deliver tender security by the prescribed deadline, while another bidder submitted a tender with conditions which were considered material.

For the four remaining tenders, BC Hydro conducted the evaluation process outlined in section 11.3 of the CFT. The Submission Evaluation Committee (SEC) re-assessed the bidders and projects to ensure compliance with the Mandatory Criteria and to determine the likelihood that the projects would achieve their commercial operation date ("COD") by May 1, 2007. All four tenders comprising 6 projects passed the SEC assessment and were forwarded to the Quantitative Evaluation Committee (QEC) for further evaluation. Throughout the tender phase, the IR was actively involved in monitoring all bidder interactions and all CFT procedures and confirmed appropriate application of the criteria.

2.8 Load Forecast Considerations

BC Hydro has prepared and published two long-term electric load forecasts since its December 2002 Load Forecast which was the basis for the VIGPN CPCN application. These forecasts take into account specific elements of the VIGP decision relevant to load forecasting methodology, in particular the use of a warmer average design temperature which has the effect of reducing the peak requirements relative to previous forecasts.[3] As shown in Section 3.2, the current forecast (October 2004 Load Forecast) predicts more load on Vancouver Island by 2007 than the 2002 forecast had, even with these design temperature changes.

Over the course of the CFT process, all indications were that the minimum portfolio size requirement of 150 MW would be insufficient to meet the expected capacity shortfall on Vancouver Island. However, to preserve the integrity of the CFT process, BC Hydro decided not to change the minimum portfolio size.

2.9 Quantitative Evaluation Methodology

In the VIGP Decision, the Commission had expressed concern about the lack of transparency associated with proprietary models developed for decision-making purposes and asked 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.[4] The Commission also encouraged BC Hydro to develop a simplified net present value ("NPV") model limited to on-

[3] A summary of the VIGP decision relevant to load forecasting and actions taken by BC Hydro is presented in Table 6 of BC Hydro's Electric Load Forecast 2003/04 to 2023/24 (October 2003 Load Forecast).
[4] VIGP Decision, p.71.

Island generation costs, without the need to consider future impacts to electricity transmission or generation on the BC Mainland.

Accordingly, BC Hydro developed the Quantitative Evaluation Methodology (QEM) to identify the most cost effective new generation solution for the Vancouver Island capacity shortfall, having regard to the cost impact of each possible portfolio of power projects. The development of the QEM was guided by the need for transparency and fairness to bidders. The methodology was initially provided to all CFT bidders in mid-November 2003, with a final version of the QEM issued on August 6, 2004 (attached as Appendix H).

In December 2003, BC Hydro had provided a simplified financial model to all registered bidders and the BCUC along with a user's manual. An evaluation methodology workshop was held on January 6, 2004 to demonstrate the evaluation spreadsheets and to respond to bidder queries. The financial model consisted of Excel spreadsheets which used monthly cash flows for the expected 25-year term of the EPA.

The QEM assessed and determined (i) the NPV of the cost and Energy Margin of the capacity and associated energy of each tender within a particular portfolio ("Net Tender Cost"), and (ii) the NPV of each portfolio, after giving effect to certain other specified impacts of that portfolio on BC Hydro and its ratepayers ("Net Portfolio Cost").

The Energy Margin was calculated by taking the difference between electricity sales revenues received when the plant was dispatched and the variable cost associated with such electricity sales. For gas-fired tolling plants, variable cost consisted of gas commodity costs established by BC Hydro as a common assumption and any interruptible gas transportation costs as provided by Terasen Gas Vancouver Island (TGVI), plus the Energy Charge supplied by the bidders. For all other plants, the variable cost was based on the Energy Charge. In order to stress test the uncertainty of future Energy Margins. BC Hydro used two electricity price scenarios. The application of these price scenarios served to reduce the expected value of the Energy Margin thereby accounting for the uncertainty of both higher relative gas costs and electricity values.

Two spreadsheets were used to execute the QEM: a Tender Spreadsheet and a Portfolio Spreadsheet. Bidders were provided with both spreadsheets in keeping with BC Hydro's commitment to full transparency. The Tender Spreadsheet calculated Net Tender Cost, using bidder inputs contained in the tender documents and embedded data sourced from third parties or BC Hydro. The Tender Spreadsheet calculated the Net Tender Cost for the gas price forecast and the corresponding two electricity price forecasts embedded in the spreadsheet.

The Tender Spreadsheet is a simplified generation dispatch model. As stated above, the risk of higher or lower relative gas prices was accounted for by using two different electricity price scenarios, one of which assumed a lower electricity price, which would result in lower dispatch and a lower Energy Margin value. In the Tender Spreadsheet, tendered plant variable costs were compared to BC Hydro's opportunity cost (two electricity market price forecast scenarios), on a monthly (heavy and light load hour) time resolution for 25 years. Based on the level of tendered plant variable costs (including fuel costs) relative to the opportunity cost, the Tender Spreadsheet assumed that the plant was dispatched on or off. The operating margin for each of these time periods was calculated and discounted as the NPV of the Energy Margin. The Net Tender Cost of each tender was calculated as the NPV of the tender fixed costs (including the capital charge) plus the NPV of the Energy Margin plus the NPV of plant start-up expenses. All calculations were undertaken in nominal dollars.

For gas-fired projects with dual fuel capability, BC Hydro assessed the availability and cost of interruptible gas transportation service from TGVI as outlined in the QEM. However, based on information provided by TGVI, it was determined there was insufficient interruptible service to warrant its inclusion in the evaluation of CFT tenders and portfolios.

For illustrative purposes, the derivation of the Net Tender Cost and the Net Portfolio Cost for a 265 MW CCGT project (extracted from the Pre-Qualification Workshop presentation) is presented in Table 3.

Table 3

Illustrative Example of Net Tender Cost and Net Portfolio Cost using 265 MW CCGT Project

	NPV	**Calculation Source**
Capital and O&M Costs	$276,371	Capital Charge + O&M Charge
Energy Margin	(127, 691)	Electricity sales less commodity costs and variable costs (per Energy Charge)
Start-Up Expense	957	Fuel required for starts
NET TENDER COST	$149,638	
VIGP Credit	(50,000)	Asset transfer price
Gas Transportation Cost	27,000	Supplied by Terasen
Network Upgrade Costs	13,000	Supplied by BCTC
NET PORTFOLIO COST	139,638	

Using outputs reported from the Tender Spreadsheet for one or more tenders, the Portfolio Spreadsheet assembled all possible portfolios of tenders aggregating not less than the CFT Minimum Capacity (150 MW) and not more than CFT Maximum Capacity (300 MW). Then, the

Portfolio Spreadsheet calculated a Net Portfolio Cost using each of the two electricity price forecasts, applied the portfolio adjustments (i.e. VIGP asset credits, network upgrade costs and the cost of firm gas transportation) and averaged the two Net Portfolio Costs. The network upgrade costs were provided by BCTC whereas the gas transportation costs were supplied by TGVI and compared to the transportation costs associated with GSX pipeline option. TGVI costs were used in the final analysis because they were lower than the estimated GSX toll. The lowest Net Portfolio Cost was the basis of the recommendation by the Quantitative Evaluation Committee ("QEC").

2.10 Gas and Electricity Price Assumptions

The natural gas price forecast stems from the Energy Information Administration's Reference Case issued in January 2004, adjusted for basis differential, currency exchange rate and extrapolation to the expiry of the term of the EPA. The Energy Information Administration is an independent, reputable organization that provides long term energy price forecasts.

Two electricity price forecasts were used (equally weighted) in the evaluation. Each forecast corresponds to the gas price forecast. The creation of the electricity price forecasts is described in detail within section 3.4 of the QEM. The "25% Capital Cost Recovery" scenario was included to stress test the economics of a gas-fired plant.

BC Hydro is active in monitoring gas and electricity prices and in managing and mitigating price exposures within its energy portfolio. BC Hydro has existing natural gas requirements as a result of its gas-fired generation facilities, a transaction infrastructure (Powerex) and the expertise to hedge this exposure on an appropriate risk and cost basis. Accepting gas tolling projects in the CFT, whereby BC Hydro assumes responsibility for gas supply, was predicated on BC Hydro's ability to use its existing portfolio to actively manage gas supply risk and electricity price risk. This active management allows BC Hydro to be flexible and respond to both risks and opportunities of gas price changes. It also means that BC Hydro seeks to retain the flexibility to proactively hedge the floating natural gas price in the short term and opportunistically dispatch the facility rather than lock in gas prices over the entire term of a full or partial tolling plant. Therefore, BC Hydro did not include in the evaluation methodology a "risk premium" above the forecast market price scenarios used in the QEM.

2.11 Tender Evaluation and Selection

The QEC opened the price envelopes for the four eligible tenders (including 6 projects) and determined the Net Tender Cost for each. The QEC then assembled the tenders into all possible portfolios aggregating between 150 MW and 300 MW of dependable capacity. One of the tenders did not qualify for inclusion in any portfolio because its bid capacity did not conform to the prescribed portfolio size thresholds. The Net Portfolio Cost was then determined for each portfolio using the Net Tender Cost with adjustments for VIGP asset value, gas transportation costs and network upgrade costs. The portfolio with the lowest Net Portfolio Cost on a net present value basis was recommended by the QEC for selection as the preferred CFT option.

The independent reviewer monitored all activities of the QEC, including the inputting of tender values into the same evaluation model that had previously been provided to all pre-qualified bidders. Furthermore, the IR insisted that BC Hydro have pre-set guidelines for determining that the results of the CFT evaluation were sufficient for making an award to the lowest cost bidder. This request was made in regard to section 17 of the CFT (i.e. privative clause) which permitted BC Hydro to determine if the Tier 1 CFT results were cost effective relative to the Tier 2 option or no CFT award whatsoever. “Tier 1” refers to the portfolio having the lowest Net Portfolio Cost NPV based on application of the QEM outlined in the CFT. “Tier 2” 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 on the basis of lowest-cost Net Tender Cost per MW, adjusted for gas transportation costs and network upgrade costs.

These decision rules focused on bidder non-collusion and the competitiveness of tenders received. The QEC applied these decision rules to determine that the Tier 1 bids were competitive and not collusive. Other aspects of the cost-effectiveness test are introduced in section 17 of the CFT are discussed in the next section.

3. Senior Management Review

3.1 Introduction

In mid-October, the findings and recommendation of the QEC were presented to BC Hydro’s senior management for review. The portfolio with the lowest Net Portfolio Cost NPV showed a considerable saving relative to the next lowest cost portfolio. Furthermore, senior management was provided with a comparison of the costs of the CFT portfolios with the VIGP Benchmark (described in section 7 below). On this latter basis, the winning CFT portfolio showed a significant saving of approximately $50 million relative to the VIGP Benchmark, plus $50 million

of further savings if the receipt of the $50 million payment from the winning bidder for the VIGP assets is taken into account.

Senior management accepted the results and recommendations of the QEC. Senior management also requested additional analysis in order to fully assess whether the selected CFT portfolio provided the most cost effective supply solution for BC Hydro's ratepayers compared to its contingency plan options and taking into account the Commission's criteria for establishing cost-effectiveness, including cost, reliability, dispatchability, timing and location. This request was also made 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 or no CFT award whatsoever.

The supplementary analysis requested by senior management reflected BC Hydro's new Electric Load Forecast and examined three possible CFT outcomes:

(a) Tier 1 – award an EPA to the 252 MW project comprising the lowest cost portfolio
(b) Tier 2 – exercise privative right and award EPAs to two smaller projects totalling 122 MW
(c) No Award – exercise the privative clause and cancel the entire CFT

3.2 Vancouver Island Demand/Supply Outlook

The cost-effectiveness analysis was completed using BC Hydro's most current demand/supply outlook for Vancouver Island and the BC Hydro system. Vancouver Island and system load assumptions were based on BC Hydro's then current annual electric load forecast for the period 2004/05 to 2024/25, which in all material respects is the same as the October 2004 Load Forecast filed with the Commission and included here as Appendix I for ease of reference. As noted, this forecast will need to be revised upward to reflect the actual rate increase approved by the Commission, thereby increasing the supply deficit on Vancouver Island.

There have also been a number of changes to the existing and committed firm capacity supply since BC Hydro's CPCN application for VIGP in March 2003. However, these changes are minor compared to the difference between BC Hydro's current electric load forecast and its December 2002 Load Forecast, which was the basis for the VIGP CPCN application. The current forecast predicts considerably higher load on the Vancouver Island by 2007 than shown in the 2002 forecast. In fact, the peak experienced in 2004 surpassed the forecast peak for 2007 contained in the 2002 load forecast.

BC Hydro's demand/supply outlook for Vancouver Island, summarized in Table 4, shows an estimated capacity requirement of 262 MW in fiscal 2007/08. This need increases on average by about 30 MW per year between 2007 and 2014. This outlook indicates that 252 MW of capacity purchased in the CFT is not sufficient to meet the load requirement in fiscal 2007/08. The gap increases further if the construction of the proposed 230 kV transmission circuit is delayed beyond the October 2008 earliest in-service date.

Table 4
Vancouver Island Demand/Supply Balance (MW)

	2004/05	2007/08	2013/14
Peak Demand	2,256	2,279	2,484
Dependable Capacity	2,221	2,016	2,016
Surplus (Shortfall)	(35)	(262)	(468)

A more detailed summary of the October 2004 peak load forecast for Vancouver Island and dependable capacity resources based on the single contingency planning standard is provided in Table 5. For comparison, Table 5 also includes BC Hydro's 2002 peak load forecast and associated capacity surplus/deficit assumed in the VIGP CPCN application; and the 2003 peak load forecast, which was filed as part of BC Hydro's 2004/05 to 2005/06 Revenue Requirement Application.

Table 5 Vancouver Island Demand/Supply Balance based on 2002, 2003 and 2004 Load Forecasts.

(MW)	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016
October 2004 Forecast before Power Smart and Transmission Losses	2,269	2,279	2,309	2,331	2,370	2,404	2,466	2,495	2,533	2,567	2,600	2,637
October 2004 Forecast with Power Smart and Transmission Losses	2,256	2,260	2,275	2,279	2,307	2,336	2,392	2,416	2,450	2,484	2,517	2,556
Power Smart	13	19	34	52	63	68	74	79	83	83	82	81
Heritage Hydroelectric including Resource Smart (450 MW)	450	450	450	450	450	450	450	450	450	450	450	450
500 kV AC Transmission (1,300 MW)	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
HVDC Transmission System (240 MW)	240	240	240	-	-	-	-	-	-	-	-	-
Existing A13Purchase C12Contracts (266 MW)	231	250	266	266	266	266	266	266	266	266	266	266
Vancouver Island Call for Tenders (250 MW)	-	-	-	250	250	250	250	250	250	250	250	250
Total Supply	2,221	2,240	2,256	2,016	2,016	2,016	2,016	2,016	2,016	2,016	2,016	2,016
Surplus / Deficit after Power Smart	-35	-19	-19	-262	-290	-320	-376	-399	-434	-468	-501	-539
December 2002 Forecast with Power Smart and Transmission Losses (used in VIGP Application)	2176	2194	2212	2228	2244	2275	2304	2336	2372	2415	2459	2504
Existing Purchase Contracts and allowance for new Green/Customer based Generation as of VIGP App'n	220	240	265	265	265	265	265	265	265	265	265	265
Balance of VI Supply (unchanged since VIGP App'n)	1990	1990	1990	1750	1750	1750	1750	1750	1750	1750	1750	1750
Surplus/Deficit in VIGP Application based on December 02 Forecast After PS	34	36	43	-213	-229	-260	-289	-321	-357	-400	-444	-489
October 2003 Forecast with Power Smart and Transmission Losses	2,152	2,165	2,175	2,201	2,220	2,256	2,280	2,300	2,332	2,360	2,400	2,441
Surplus/Deficit based on October 2003 Forecast After PS	70	75	82	-185	-203	-240	-263	-284	-315	-343	-384	-424

October 2004 Load Forecast: As presented in Appendix I, BC Hydro's load forecast includes regional peak forecasts for the Lower Mainland, Vancouver Island, Northern Region and South

Interior. The current peak load forecast for Vancouver Island is substantially higher as compared to the 2002 and 2003 regional forecasts for two reasons:

- higher actual and forecast economic growth assumptions relative to prior projections; and
- re-calibrated peak loads due to actual peak demand which occurred on January 5, 2004.

The basis for the changed economic assumptions and the recalibration of the model are fully set out in Appendix J.

Power Smart and Vancouver Island Dependable Capacity: Based on the Power Smart savings achieved to date and estimated savings going forward, BC Hydro has updated its forecast of capacity reductions from that assumed at the time of the VIGP hearing. There are also minor changes to Vancouver Island's dependable capacity supply since the VIGP hearing. Neither the revised Power Smart contributions nor changes to the Vancouver Island dependable capacity had material impacts on the cost-effectiveness analysis.

In summary, the current demand/supply outlook for Vancouver Island indicates a shortfall of 262 MW in F2008 without any contribution in that year from the CFT. The acquisition of 252 MW as a result of the CFT addresses 95% of the shortfall, and less with the pending load forecast revision. Even with this acquisition, the preferred timing of new 230 kV AC cable circuit to Vancouver Island remains at that project's earliest in-service date of F2009.

3.3 Cost-Effectiveness Analysis

As described above, the CFT provided BC Hydro with the discretion to consider bids received that did not meet Tier 1 standards relative to portfolio size and cost-effectiveness and to consider accepting no bids at all if it was concerned that no Tier 1 bid was cost-effective compared to the contingency options. The cost-effective analysis sought to confirm that the winning Tier 1 bid was cost effective relative to these alternatives.

Depending on which CFT outcome is being considered, the amount, type, cost and timing of the resources required by BC Hydro to meet the system and Vancouver Island needs would be different. Therefore, the general approach was to examine the NPV of each Tier 2 CFT outcome against the winning Tier 1 bid, incorporating the different attributes and costs of the resource options. The best outcome is the one that results in the lowest NPV cost to BC Hydro and its ratepayers on a risk-adjusted basis i.e. recognizes cost and time certainty.

In order to fairly compare the best Tier 1, Tier 2 and no award (i.e. contingency) alternatives, it was necessary to equalize both the energy and the capacity being added to the system. Based on the most recent load forecast and supply outlook, the system was assumed to require additional energy starting in 2010. The total volume of new energy supply being added to the system under each of the three CFT outcomes was based on the energy contribution from the Tier 1 plant, which translated to approximately 1,800 GWh per year as determined by the dispatch model used in the QEM. Thus, for all three alternatives, it was assumed that 1,800 GWh of energy was required from 2010 onward but supplied in varying amounts from the CFT outcome, mainland generation or bridging sources.

With respect to capacity, BC Hydro identified a number of contingency measures to address any supply shortfalls on Vancouver Island that might arise if insufficient capacity was provided by the CFT outcome. These measures include load curtailment and load shifting options, use of emergency generation units, increasing operational reliability of the HVDC transmission system, and various other DSM and rate options. These contingency measures entail risks and uncertainties related to volume, cost and in-service date.

For the cost-effective analysis, any unmet requirement on Vancouver Island was filled first with load curtailment based on Norske's recent Demand Management proposal and then, if necessary, with TM-2500 temporary generators. These two options were viewed as being the most cost effective among the suite of contingency measures. Both the Norske load curtailment and the temporary generation option were assumed to operate 240 hours per year to meet the load requirement.

The common assumptions used for the analysis of CFT cost effectiveness are as follows:

- Vancouver Island supply shortfall – 261 MW
- 230 kV transmission cable – in service after March 2009
- Mainland generation – electricity price same as Tier 1 CFT result i.e. 250 MW CCGT
- Norske Demand Management[6] – capacity up to 140 MW with minimum commitment of 30 MW for three years
- Temporary generation – GE distillate-fired mobile units sized at 23 MW each
- Gas and electric prices – used Energy Information Administration ("EIA") forecast as described in QEM

[6] Filed with BCUC in British Columbia Transmission Corporation's Capital Plan Application as Exhibit C1-4: Letter and Demand Management Proposal dated September 2, 2004

- Gas transportation tolls – used estimated tolls provided by TGVI, which were lower than the projected tolls on the GSX system

3.4 Results/Conclusion

The results of various scenarios relative to the Tier 1 outcome represented by the EPA award to Duke Point Power Limited Partnership are summarized in Table 6. A more detailed summary of the approach and results is provided in Appendix J.

Table 6

Summary of Cost-Effectiveness of Tier 1 Outcome Against Tier 2 and No CFT Award Under Various Planning Scenarios

	NPV of Incremental Cash Flows ($2003 millions)		
	Tier 1 – 252 MW	Tier 2 – 122 MW	No Award
Base Case	$ -	$ 88	$ 53
230 KV Cable Delayed 1 Year	-	106	90
High Gas Prices (~$7/GJ)	-	2	(33)
Mainland Power Cost –10%	-	21	(47)
VI Supply Shortfall = 150 MW	-	53	2
VI Supply Shortfall = 350 MW	-	116	87

Under the base case scenario, Tier 1 shows a savings of $88 million and $53 million over Tier 2 and No Award scenarios respectively. The relative cost benefit of the Tier 1 option increases as the in-service date of the transmission cable is delayed. Consequently, because of its size and economies of the scale, Tier 1 is the CFT outcome most capable of mitigating any delay in the 230 kV cable.

For the sensitivities shown above, the Tier 1 award is always less expensive than the Tier 2 award. However, the “No Award” scenario provides lower costs based on the sensitivities for higher gas prices and lower Mainland generation costs.

Overall, from a purely quantitative standpoint, Tier 1 shows the lowest cost to ratepayers, especially when taking the uncertainty of the 230 kV circuit installation into consideration. Relying on bridging solutions to provide reliable power supply to Vancouver Island carries additional non-quantitative risks and uncertainties. For instance, there are permitting risks associated with temporary generators (e.g. operating restrictions and duration of service). For the Demand Management proposal, the need to negotiate a suitable curtailment arrangement with Norske Canada carries uncertainty relative to the outcome of the CFT process with its legally binding bids and fixed prices.

The conclusion of the cost-effectiveness analysis was that the Tier 1 result (awarding an EPA to the Duke Point Power Project) is the most cost-effective outcome for ratepayers on both a quantitative and risk-adjusted basis. As stated in the VIGP Decision, cost effective includes considerations such as reliability, dispatchability, timing, location, safety and cost to ratepayers and the financial capability of the utility.

4. CFT Award

After careful consideration, BC Hydro's senior management determined that the acceptance of the recommended portfolio represented the most cost-effective solution for addressing the Vancouver Island supply shortfall having regard to ratepayer interests. On October 20, BC Hydro's board of directors endorsed the selection of the recommended portfolio and the award of an EPA to the lowest cost Tier 1 proponent.

On November 3, BC Hydro announced that the preferred CFT option is a 252 MW gas-fired combined cycle power plant to be located near the Duke Point industrial area of Nanaimo, B.C. The project owner, Duke Point Power Limited Partnership, 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 Duke Point Power LP was fully executed on November 16, 2004.

5. CFT Process Management and Independent Review

5.1 CFT Process Management Framework

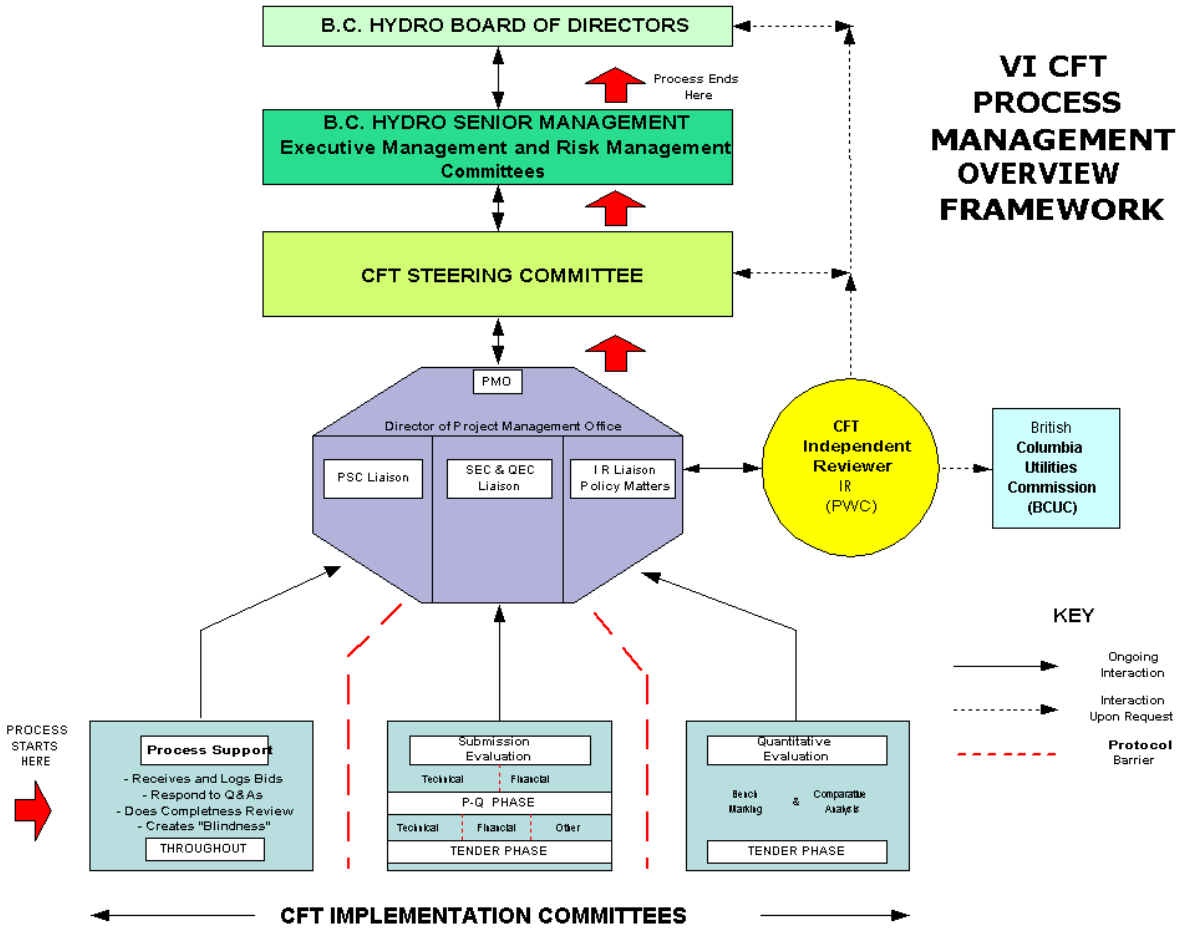
To meet the Commission's direction, as well as the other key objectives of the CFT, BC Hydro develop a detailed process management framework to successfully administer and manage the CFT. This management framework was designed to fulfil the objectives of the CFT and to meet the fairness objective ascribed by the Independent Reviewer (IR). It provides a clear assignment of mandate, rules, duties and responsibilities, and persons involved for all phases of the CFT process. A summary of responsibilities, relationships, and reporting and process flow structures is illustrated in Figure 1 on the following page.

An important aspect of the process management framework are the embedded protocol barriers to keep the process "blind" and in alignment with required standards of fairness, objectivity, conflicts of interest, completeness, and consistency. The IR, however, was not blinded in any way, throughout the CFT process to allow them to report on BC Hydro's management of the CFT.

5.2 Role of the Independent Reviewer

To promote fairness and transparency, BC Hydro retained PricewaterhouseCoopers (PwC) to act as independent reviewer (IR) for the CFT. At the outset of its engagement, PwC developed a fairness framework for the CFT which was based on the primary elements of competitiveness, fairness and transparency. This framework was outlined in *Report No. 4 of the Independent Reviewer*, issued on October 29, 2004 following the conclusion of the Tender phase.

Figure 1 Overview of VI CFT Process Management Framework



5.3 IR Review and Monitoring

It is important to note that the independent reviewer was integrally involved in each step of the CFT process, observing and monitoring all interactions with bidders and all internal BC Hydro deliberations. During the course of the CFT, the IR issued four reports on the various phases of the process. These reports are attached as Appendix K and contain the following key findings:

- Report #1 (October 29, 2003): "*BC Hydro has established an appropriate foundation of processes and governance for the CFT. With this foundation, our judgement is that the*

VICFT is capable of producing a result that meets the objective for a fair and transparent competition."

- Report #2 (December 15, 2003): *"It is our finding that BC Hydro, with respect to the VICFT initiation and registered bidder comment stage, has executed its responsibilities in a fair, transparent and objective manner and in accordance with the requirements of the VICFT*."

- Report #3 (April 29, 2004): *"It is our judgement that BC Hydro, with respect to the conduct of the Pre-Qualification phase of the CFT, have made determinations for each of the 14 submissions that were in accordance with the established processes and criteria and are appropriately consistent, objective and fair."*

- Report #4 (October 29, 2004): *"Based on their stated scope, requirements and timing, BC Hydro diligently and objectively developed and implemented an appropriately competitive, transparent and fair process for the Tender Phase."*

In its final report, PwC also made the following concluding statement: *"With respect to the conduct of BC Hydro of the entire process, it is our finding that it was a competitive process and conducted in a fair and transparent manner."*

6. Rate Impact

In order to assess the rate impact of the new EPA with Duke Point Power LP, an incremental rate impact analysis was conducted using the results of BC Hydro's recent 2004 Revenue Requirements Application decision as the base scenario. The results of this rate impact analysis are summarized in Table 7.

Table 7

Summary of Rate Impact Analysis of CFT Award Compared to VIGP Benchmarks

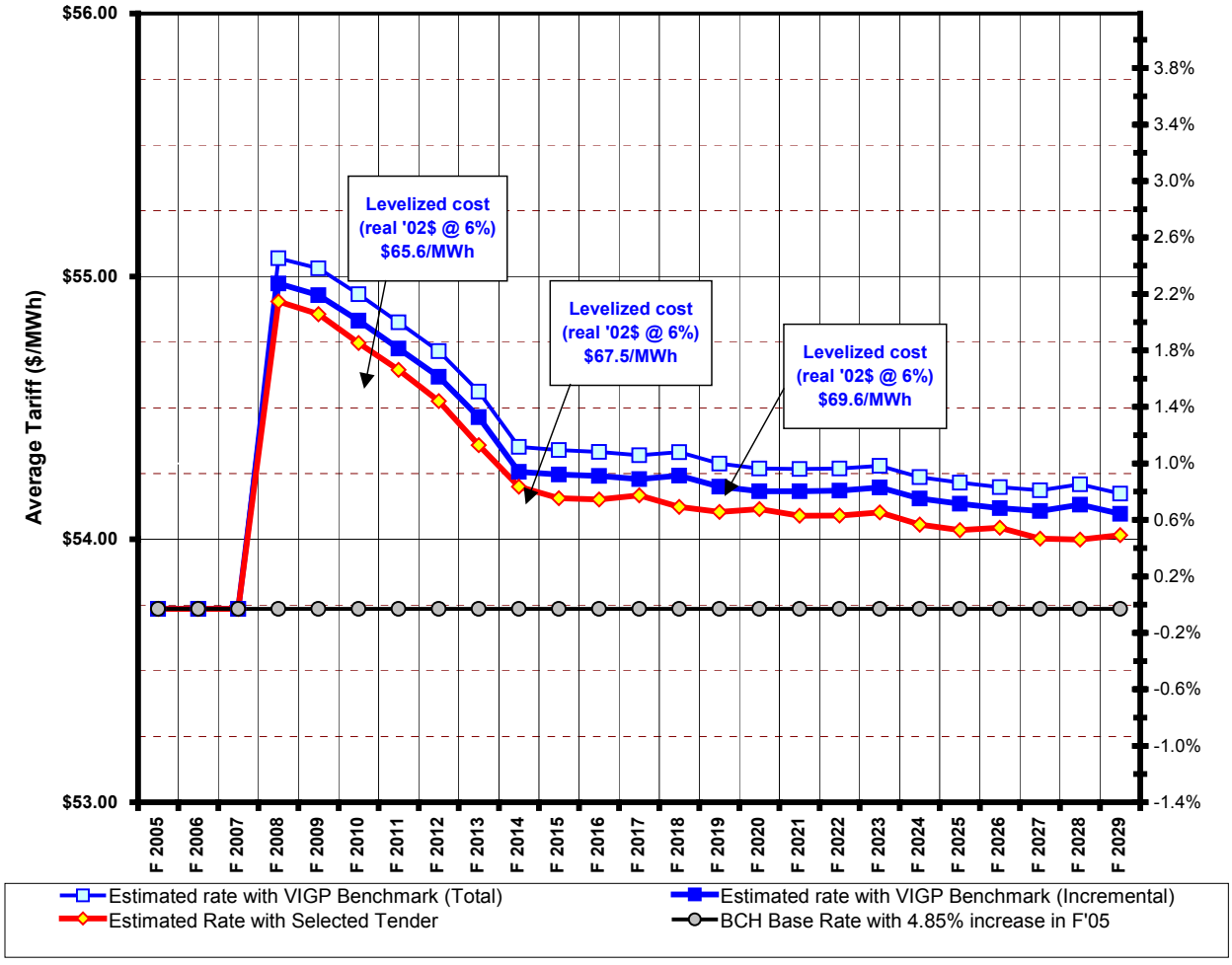
	F2005	F2006	F2007	F2008	F2009	F2010	F2011
BC Hydro Base Rate - $/MWh	53.7	53.7	53.7	53.7	53.7	53.7	53.7
New BC Hydro Rate - $/MWh	53.7	53.7	53.7	54.9	54.9	54.6	54.5
Rate Impact of CFT Award - Duke Point Power	0.0%	0.0%	0.0%	2.2%	2.1%	1.9%	1.7%
Rate Impact of VIGP Benchmark – Incremental Cost	0.0%	0.0%	0.0%	2.3%	2.2%	2.0%	1.8%
Rate Impact of VIGP Benchmark – Total Cost	0.0%	0.0%	0.0%	2.5%	2.4%	2.2 %	2.0 %

As shown above, the purchase of electricity from the Duke Point Power Project is projected to have an annual rate impact of approximately +2.0% for the first four years of the project. This rate impact is somewhat lower than calculated for the VIGP benchmark which approximates +2.2% per year for F2008-F2011.

The "Incremental Cost" calculation for the VIGP benchmark is based on the average capital cost ($355 million) less sunk costs of $51 million as prescribed in the VIGP Decision. For the "Total Cost" scenario, the sunk costs are added back in so as to reflect the total cost of the VIGP self-bid option. This VIGP Total Cost scenario is truly comparable to the Duke Point Power plant given that the latter project reflects a market bid with a $50 million transfer value for VIGP assets (i.e. recovery of sunk costs).

The long term rate impact of the CFT award compared to the VIGP benchmark is illustrated in Figure 2.

Figure 2 CFT Award Rate Compared to VIGP Benchmark Rate



7. VIGP Benchmark

In its VIGP Decision, the Commission requested that BC Hydro provide a comparison of the CFT outcome to the "CFT Benchmark" outlined on page 81 of the Decision. This benchmark is effectively the VIGP plant built by BC Hydro with modified assumptions and is therefore referred to as the "VIGP Benchmark" for ease of reference. The results of the VIGP Benchmark analysis are contained in Appendix L.

In summary, BC Hydro has modified some of the assumptions outlined in the VIGP Decision, as follows:

- For gas transportation, used the tolls provided by TGVI rather than 50% of the updated GSX toll plus $0.60 on-Island TGVI toll prescribed by the BCUC.
- Price Forecasts: the QEM used updated natural gas and electricity price forecasts.
- Generation plant performance: BC Hydro used the dispatchable features in the evaluation model to determine the energy generated by the updated VIGP Benchmark.

In answer to previous Q&A's, BC Hydro committed to releasing the VIGP benchmark data. However, since that time BC Hydro determined that the benchmark contains assumptions which are inconsistent with the CFT process and includes some outdated data. Accordingly, BC Hydro did not publish the VIGP benchmark. A summary of the VIGP Benchmark is presented in Table 8.

Table 8

Summary of VIGP Benchmark

(2006 beginning of year dollars)

Scenario	EIA-Full	EIA-Partial	Average
Capacity Charges NPV ($000)	314,415	314,415	314,415
Fixed O&M Charges NPV ($000)	179,513	179,513	179,513
Capacity and O&M Cost NPV ($000)	493,928	493,928	493,928
Market Value of Energy NPV($000s)	1,317,276	969,047	1,143,162
Variable Costs of Dispatch (NPV$000s)	1,073,237	893,573	983,405
Energy Margin NPV($000)	244,039	75,475	159,757
Startup Cost NPV ($000)	24,493	24,493	24,493
Net Tender Cost NPV ($000)	274,382	442,947	358,665
Average Annual Dispatch GWh	2,003	1,699	1,851
Capacity Factor over Term	86%	73%	80%
Total Tender Cost NPV (Not Net) ($000)	1,591,658	1,411,994	1,501,826
NPV (6%) Dispatch MWh	24,463,144	20,731,886	22,597,515
Levelized Cost ($/MWh)	**70.6**	**74.6**	**72.4**

8. Electricity Purchase Agreement

A preliminary, pro forma version of the EPA was publicly posted on October 31, 2003 at the time of the original issuance of the CFT. The EPA was substantially revised on January 13, 2004 in response to numerous comments received from registered bidders. Further changes to the Preliminary Form EPA were made on April 22, 2004 to reflect the impact of directional comments from the BCUC and various CFT Addenda.

BC Hydro made several changes to the EPA that benefited bidders and rendered some of the terms and conditions less onerous. However, the relative risk allocation contained in the EPA reflects the timing and reliability imperatives associated with the Vancouver Island CFT. Thus, the supplier bears the risks for plant construction, schedule, operating performance (e.g. heat rate) and GHG liabilities. Failure to meet the supply obligations in a timely manner results in the successful bidder being subject to significant financial penalties such as liquidated damages and forfeiting of contractual securities.

The Final Form EPA was issued on June 23, 2004 in response to comments received from pre-qualified bidders. A summary of the key changes in the Final Form EPA relative to the previous Preliminary Form EPA was also posted on BC Hydro's website (see Appendix M). BC Hydro issued a Revised Final Form EPA on July 30, 2004 to correct errors, provide clarification, and provide a final response to certain bidder issues. A copy of the finalized EPA executed by BC Hydro and Duke Point Power LP is attached as Appendix N.

For reference, a copy of the final VIGP Asset Transfer Agreement is also provided in Appendix O.

9. Requested Decision from the Commission

The successful proponent that emerged from the CFT process proposes to supply BC Hydro's needs on Vancouver Island by acquiring the assets of VIEC, constructing a CCGT at the Duke Point site, and selling all of the output from the plant back to BC Hydro. The result is that, in many respects, this proposal and the VIEC proposal are similar. For that reason, BC Hydro considers the CFT process to be a continuation of the VIGP CPCN process.

Despite the similarity of the physical projects, the sale of the Duke Point assets by VIEC to Duke Point Power Limited Partnership means the issues now before the Commission are distinct from those it was charged with considering earlier in the VIGP proceeding. Duke Point Power was selected by a competitive process and not by the Commission based on an application. A truly

competitive process should produce a cost-effective outcome. Thus, in BC Hydro's submission, the Commission should now focus on the competitiveness of the process, rather than second guess its outcome. Shortly put, BC Hydro submits that the central issue now before the Commission is whether the process was fair, transparent and appropriate to reach a solution in the best interests of ratepayers.

BC Hydro respectfully requests that the Commission take the steps it believes are necessary to satisfy itself that the CFT process met these criteria. If it concludes the criteria were met, the Commission should so indicate, and after doing so, need take no further steps.

BC Hydro notes that in Order G-99-04 the Commission referenced its commitment to an expedited review process for any EPA arising out of the CFT process. The BCUC has begun to honour that commitment, even before receiving this Report, by setting down a Procedural Conference for November 29. 2004. BC Hydro very much appreciates the Commission taking that step and looks forward to the process completing as quickly as possible.

BC Hydro notes several principal features of the CFT process that make lengthy public review unnecessary and any attendant further delay undesirable:

1. The process design was fully transparent; each bidder knew BC Hydro's evaluation methodology and therefore could adapt their tender to provide maximum value under that methodology.

2. The process design took into account extensive comments from potential and actual participants in the process. Moreover, the Commission itself was given an opportunity to publicly comment on the design and resulting in numerous adjustments to the final CFT structure.

3. BC Hydro and CFT bidders undertook significant financial and legal commitments by participating in the CFT process and its outcome should be honoured to the maximum extent possible so long as the Commission is persuaded the process was fair and BC Hydro complied with it.

4. A qualified independent reviewer has issued a report certifying that CFT process was carried out in a fully transparent and fair way in accordance with the process design and that there was no evidence of bidder collusion.

5. The final valuations as described above used the models and assumptions that were fully disclosed through the CFT process.

6. A solution to Vancouver Island's capacity problems has been sought for over 10 years. Every plausible solution has been extensively studied. Through the CFT process, all those with their own ideas of how to provide a solution have been offered the opportunity to come forward and many responded. Reliable supply on Vancouver Island depends on proceeding on with the project that has emerged as the winner in this process.

7. The accepted tender will impose lower net present costs than the VIGP benchmark established by the Commission and will result in lower rates. Not only was it the most attractive Tier 1 tender, it also proved to be cost effective against portfolios containing projects that did not meet the Tier 1 criteria.

In short, the transparency of the process has left little room for surprises and little need for further discovery or fact finding. In these circumstances, BC Hydro believes that an expedited process as referred to by the Commission is entirely appropriate. BC Hydro looks forward to participating in whatever process the Commission establishes for review of the CFT process commencing with he November 29, 2004 Procedural Conference.