1.0 Reference: CFT Main Report, pages 3 (line 16) and page 12 (lines 28-29)

1.1.1 Please provide copies of any analyses or reports prepared by/for BCH to support the view that BCH did not need to include in the evaluation methodology a "risk premium" for projects adopting the "gas tolling option"?

RESPONSE:

Please see the response to BCUC IR 1.17.1.

2.0 Reference: CFT Main Report, page 4, (lines 5-7) and page 5 (lines 17-21)

1.2.1 Please outline what role, if any, the IR (Independent Reviewer) played in determining which comments or issues raised by parties regarding the original CFT would be addressed in the revised CFT issued on January 13, 2004.

RESPONSE:

The Independent Reviewer reviewed all comments made by bidders and monitored BC Hydro's deliberations and preparation of responses. The IR's participation included sitting in on all meetings regarding bidder comments and reviewing all successive drafts of BC Hydro's written responses.

Further details on the IR's role regarding bidder comments and issues can be found in the *Second Report of the Independent Reviewer* dated 15 December 2003 (see Appendix K-2 of the CFT Report). This report contains the following observations and conclusions:

- **"We monitored the information exchange process by either attending and/or reviewing the drafting of responses and positions by BC Hydro. We observed an objective and impartial response to questions and comments."**
- **"We monitored BC Hydro's process of compiling, developing and approving the responses and rationale for the comments and/or proposed amendments to the VICFT submitted by the registered bidders [by 01 December 2003]. We observed an objective and impartial consideration of all comments and/or proposed amendments."**
- **"[BC Hydro has d]emonstrated objective, impartial and unbiased, and thorough and transparent approaches to developing and responding to registered bidders' comments, questions and amendments to the VICFT."**

3.0 Reference: Appendix F and CFT Main Report, page 7, Table 2

1.3.1 In its January 23rd, 2003 letter the BCUC noted that "Many parties feel that the CFT was structured to favour gas-fired generation, particularly a facility like VIGP". Did BCH incorporate any changes in the revised CFT to address this concern and, if so, please outline what they were?

RESPONSE:

The major change made by BC Hydro in response to the Commission's letter of January 23, 2004 was the removal of the Transmission Deferral Credit per Addendum No. 10 issued on March 5, 2004. As noted in the Addendum, no capacity credit was to be applied in the Quantitative Evaluation Methodology (QEM) for capacity in excess of 150 MW. This revision 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 NPV of least cost.

BC Hydro made subsequent revisions to the CFT and EPA which provided bidders with increased flexibility and further levelled the playing field across different technology types and for projects less advanced than VIGP. These changes included the following:

- **Relaxed test for termination based on poor availability;**
- **Relief relative to the failure to obtain Material Permits;**
- **Increased opportunity to recover from a poor Demonstration Test;**
- **Increased opportunities to recover from a reduction in Nominal Capacity; and**
- **Relief from Nominal Capacity reduction during first year post-COD.**

3.0 Reference: Appendix F and CFT Main Report, page 7, Table 2

1.3.2 In its January 23rd, 2003 letter the BCUC stated that "BC Hydro should not expect that a transmission deferral credit will be accepted by the Commission Panel". Would the retention of a transmission deferral credit, as originally proposed by BCH, have altered either:

- The Tier 1 results or
- The relative cost-effectiveness results for Tier 1, Tier 2 and No Award as set out in the Base Case in Table 6 (page 18)?

RESPONSE:

a) This Information Request is out of scope.

b) No, because in all scenarios, new VI transmission is required at its earliest in-service date.

4.0 Reference: CFT Main Report, page 8, lines 14-18

1.4.1 Please indicate which of the Mandatory Criteria (as per Section 9.8 of the CFT) each of the three bids failed to meet.

RESPONSE:

This Information Request is out of scope.

5.0 Reference: CFT Main Report, page 8 (lines 10-11) and page 8 (lines 28-29) Appendix K, IR Report #4, page 13

1.5.1 Of the ten proposed projects, please indicate how many of them were "VIGP projects."

RESPONSE:

Five.

(6.0) Reference: CFT Main Report, page 8 (lines 10-11) and page 9 (lines 3-10)
Appendix K, IR Report #4, page 13

1.5.2 (1.6.0) For the final four Tenders, which included 5 natural gas projects, how many of the projects were "VIGP projects"?

RESPONSE:

In the final four Tenders, which included 5 natural gas projects and 1 biomass project, four projects were for the VIGP project.

7.0 Reference: CFT Main Report, page 9 (lines 13-15)

1.7.1 Please provide a copy of Table 6 from BC Hydro's October 2003 Load Forecast.

RESPONSE:

Table 6. Decisions and Summary Responses

Decision	Action
1. More appropriate to use load forecast before Power Smart rather than with Power Smart in comparing historical growth rates.	1. Both before Power Smart and with Power Smart forecasts are shown to increase transparency of the forecast in Sec. 5.
2. Provide an understanding of the methodology, input data and impacts of drivers.	2. Methodology is presented in Sec. 3, input data in Sec. 4 and impacts of drivers in Sec. 7.
3. Transparency of weather normalization, back-casting and assumptions need improvement.	3. Weather normalization is reviewed in App. 3 and App. 4, alternative forecasts in App. 5, back-casting for peak in Sec. 11 and App. 6, and assumptions in Sec. 4.
4. Include the following in future applications for major project additions: • Explanation of the selected methodology and alternatives considered; • Listing of data sources and assumptions; • Validation of the modelled outputs; • Comment on growth trends.	4. Incorporated in current forecast: • Algorithms used are explicitly stated in Sec. 3 as are a variety of regression-based alternatives in App. 5 and App. 6; • Data sources and key growth assumptions are provided in Sec. 4; • Regression modelling is used to validate the modelled outputs in App. 5 and App. 6; • Growth trends are summarized in Sec. 5.
5. Use updated numbers for Power Smart when calculating peak demand for Vancouver Island.	5. Most recent 10-Year Power Smart plan as summarized in Sec. 12 has been used for the forecast with Power Smart.
6. Adjust BC Hydro peak forecasts between 2003/04 and 2011/12 to reflect lower population growth on Vancouver Island.	6. Forecasts of numbers of accounts for all regions, including Vancouver Island, have been adjusted to reflect most recent population forecasts and peak is lower than last year's estimates for all years of the forecast period.
7. Use of -3.7 degrees Celsius based on 30-year rolling average is appropriate for Vancouver Island.	7. For this forecast, design-day temperatures of minus 6.8 degrees Celsius for the system and minus 4.4 degrees Celsius for Vancouver Island are being used. A review is underway to determine the most appropriate design-day temperatures.
8. Adjust the peak for Vancouver Island downward to adjust for anticipated rate changes.	8. Scenarios have been developed using a range of relevant elasticities from recent third party studies in high cost jurisdictions and from internal econometric estimates to provide indicative information.
9. Adjust peak for 2007/08 and 2011/12 downwards in order to account for negative variances.	9. Compared to last year's forecast, the peak for Vancouver Island has been adjusted downward by 26 MW for 2007/08 and 35 MW for 2011/12 before Power Smart.

8.0 Reference: CFT Main Report, page 11 (lines 13-16)

1.8.1 Please clarify, based on this paragraph, what gas transportation cost assumptions were used in the QEM in the case of gas-fired projects with dual fuel capability, e.g., were firm transportation prices used?

RESPONSE:

Firm gas transportation prices were used to evaluate portfolios with dual fuel projects. The QEM was set up to evaluate dual fuel projects with both firm and interruptible gas transportation costs. However, due to insufficient availability of interruptible gas transportation capacity in the expansion plans provided by TGVI, none of the dual fuel projects were evaluated under the interruptible gas transportation option.

9.0 Reference: CFT Main Report, page 12 (lines 10-11 and lines 18-19)

1.9.1 BCH states that it "is active in monitoring gas and electricity prices." Please provide copies of all reports and studies regarding future natural gas prices that BCH has prepared internally, commissioned or obtained in last 12 months.

RESPONSE:

Many of BC Hydro's reports and studies on gas and electricity prices are subscription-based (CERA; PIRA; Wood MacKenzie; CERI) and cannot be distributed.

The natural gas price forecast used in the CFT Quantitative Evaluation is derived from the Energy Information Administration. This can be obtained at the EIA website: http://tonto.eia.doe.gov/FTPROOT/forecasting/0383(2004).pdf.

9.0 Reference: CFT Main Report, page 12 (lines 10-11 and lines 18-19)

1.9.2 Please provide a schedule contrasting the projected prices for natural gas from each of these sources with the forecast BCH prepared based on the EIA's January 2004 Reference Case forecast. Please identify all assumptions and factors impacting on the comparability of the natural gas price forecasts provided in the schedule.

RESPONSE:

This Information Request is out of scope.

10.0 Reference: CFT Main Report, pages 13 (lines 31-32) and 23 (Table 8)

1.10.1 Please re-state Table 8 in $2003 consistent with Table 6.

RESPONSE:

Please see Table IR 1.10.1 below.

Table IR 1.10.1 - Summary of VIGP Benchmark (2003 beginning of year dollars)

Scenario	EIA-Full	EIA-Partial	Average
Capacity Charges NPV ($000)	249,593	249,593	249,593
Fixed O&M Charges NPV ($000)	142,503	142,503	142,503
Capacity and O&M Cost NPV ($000)	392,096	392,096	392,096
Market Value of Energy NPV ($000)	1,045,696	769,261	907,479
Variable Costs of Dispatch NPV ($000)	851,970	709,347	780,659
Energy Margin NPV ($000)	193,726	59,914	126,820
Startup Cost NPV ($000)	19,443	19,443	19,443
Net Tender Cost NPV ($000)	217,813	335,749	284,720
Average Annual Dispatch (GWh)	2,003	1,699	1,851
Capacity Factor over Term	86%	73%	80%
Total Tender Cost NPV (Not Net) ($000)	1,263,509	1,120,886	1,192,198
NPV (6%) Dispatch (MWh)	24,463,144	20,731,886	22,597,515
Levelized Cost ($/MWh)	66.3	70.1	68.0

10.0 Reference: CFT Main Report, pages 13 (lines 31-32) and 23 (Table 8)

1.10.2 Please clarify the basis of comparison that gave rise to the $50 M saving – prior to any allowance for the VIGP assets - referenced on page 13: i.e., was the Net Portfolio cost of the winning CFT portfolio used in the comparison and was it compared with the Total Tender Cost of the VIGP benchmark?

RESPONSE:

The winning CFT portfolio has a Net Portfolio Cost of about $100 million lower than the Net Portfolio Cost of the VIGP benchmark. In this comparison, the Net Portfolio Cost of the winning CFT portfolio received a $50 million credit (as described in the QEM) that represents the $50 million payment that BC Hydro will receive from Duke Point Power for the VIGP assets.

The $50 million payment is a cost to Duke Point Power that they would have been built into their bid price. The VIGP benchmark received no such credit because the capital cost used to calculate the Net Portfolio Cost for the VIGP benchmark was based on incremental capital costs only, i.e. sunk capital costs were excluded. If the $50 million payment from Duke Point Power is not taken into account, the savings would be reduced to $50 million, although this would be a misleading comparison from a ratepayer perspective.

11.0 Reference: CFT Main Report, page 13 (lines 28-29)

1.11.1 Please indicate the level of savings (i.e., the difference in NPV) between the winning CFT portfolio and the next lowest cost Tier 1 portfolio.

RESPONSE:

The information requested is confidential.

11.0 Reference: CFT Main Report, page 13 (lines 28-29)

1.11.2 Please confirm whether the next lowest cost (Tier 1) Portfolio involved:

a) a VIGP election

b) a Full Tolling or Partial Tolling election.

RESPONSE:

The next lowest cost (Tier 1) project was a portfolio of one project, consisting of a VIGP election project *with* duct firing. The Full Tolling election was made for this tender.

12.0 Reference: CFT Main Report, page 14 (lines 29-31)

1.12.1 Please indicate whether the peak experienced in 2004 and being compared with the value for 2007 (contained in the 2002 forecast) is the “actual peak” or a “weather normalized peak”. If the former, please provide the comparison after weather normalization.

RESPONSE:

The values being compared in lines 29-31, page 14 of the CFT Report are the weather-adjusted peak for F2004 (2,240 MW) and the December 2002 Vancouver Island peak forecast for F2008 (2,228 MW).

13.0 Reference: CFT Main Report, pages 14 (line7) & 17 (lines 10-19) and Appendix J, page 2

1.13.1 Are the contingency plan options referred to on page 14 of the Main Report the Demand Management Proposal submitted by Norske Canada and the Temporary Generators as described in Appendix J?

RESPONSE:

Yes.

13.0 Reference: CFT Main Report, pages 14 (line7) & 17 (lines 10-19) and Appendix J, page 2

1.13.2 Reference is made on page 17 to a "suite of contingency measures". Are there any other "contingency options" available to BCH for the winter of 2007/08? If so, please describe what they are including details regarding capacity available, energy capability and costs.

RESPONSE:

Please see BC Hydro response to BCUC IR 1.40.2.

13.0 Reference: CFT Main Report, pages 14 (line7) & 17 (lines 10-19) and Appendix J, page 2

1.13.3 Has BCH confirmed with Norske Canada that its Demand Management Proposal is still valid and can provide 240 hours of relief? If so, how recently was this done?

RESPONSE:

No.

14.0 Reference: CFT Main Report, page 15, Tables 4 and 5

1.14.1 Please provide the specific cross-references to Appendix I (2004 Load Forecast) indicating where the Peak Demand forecasts shown in Tables 4 and 5 can be found.

RESPONSE:

The peak values in Table 4, pg 15 of the CFT Report are the peak forecasts for Vancouver Island including transmission losses with Power Smart. These forecasts are not published in Appendix I. The corresponding peak forecasts to the values in Table 4, excluding transmission losses, are published in Appendix I in table 11.5, pg.83. The corresponding forecasts are F 2005 (2,146 MW), F2008 (2,177 MW) and F2014 (2,374 MW), excluding transmission losses.

The peak values in first two lines in Table 5, pg. 15 of the CFT Report are the peak forecasts for Vancouver Island including transmission losses before and with Power Smart. These forecasts are not published in Appendix I. The corresponding peaks to the peak values in the first two lines in Table 5, excluding transmission losses, are published in Appendix I in Table 11.4, page 82 and Table 11.5, page 83.

14.0 Reference: CFT Main Report, page 15, Tables 4 and 5

1.14.2 The text (line 11) indicates that the dependable capacity resources shown in Tables 4 and 5 are based on a "single planning contingency standard". Please indicate the megawatt value of the "single planning contingency standard" and how it has been factored into Table 5, which appears to simply list the capability of individual supply resources.

RESPONSE:

The single planning contingency is factored into Table 5 by excluding the capability of the single largest Vancouver Island supply elements which is one of the two 500 kV AC circuits from the Mainland. In the application of the single planning contingency standard, the peak demand is compared to the total dependable capacity of supply elements with the largest element of supply unavailable. Therefore, Table 5 only includes the dependable capacity of one of the 500 kV AC circuits. The continuous rating of these circuits is 1200 MW each. Table 5 reflects the two-hour overload capability of one of these 500 kV AC circuits, which is 1300 MW.

14.0 Reference: CFT Main Report, page 15, Tables 4 and 5

1.14.3 Please confirm that the peak demand values shown in the table are based on the average coldest day as opposed to an extreme coldest day (e.g., single coldest day in 10 years).

RESPONSE:

Confirmed.

14.0 Reference: CFT Main Report, page 15, Tables 4 and 5

1.14.4 Please indicate by how much the Vancouver Island 2004 peak demand forecast would increase if based on an extremely cold day (e.g., the single coldest day in 10 years) as opposed to the average coldest day.

RESPONSE:

Table IR 1.14.4 below shows the difference between the Vancouver Island Peak forecast based on a design temperature with a probability of exceedence of 1 in 10 years and the Vancouver Island peak forecast as contained in Table 5, page 15 of the CFT Report, which is based on design temperature with a probability of exceedence of 1 in 2 years.

Table IR 1.14.4
Peak Forecasts Based on Different Design Temperatures

	Peak Forecast As contained in CFT Report (1 in 2 Years Design Temperature)	Peak Forecast (1 in 10 years Design Temperature)	Difference In Peak
	Column A	Column B	B-A
	(MW)	(MW)	(MW)
2004/05	2,256	2,387	131
2005/06	2,260	2,392	133
2006/07	2,275	2,410	135
2007/08	2,279	2,416	138
2008/09	2,307	2,447	141
2009/10	2,336	2,480	144
2010/11	2,392	2,539	146
2011/12	2,416	2,565	149
2012/13	2,450	2,602	152
2013/14	2,484	2,638	154
2014/15	2,517	2,673	156
2015/16	2,556	2,715	159
2016/17	2,595	2,756	162
2017/18	2,634	2,799	164
2018/19	2,675	2,842	167
2019/20	2,716	2,886	170
2020/21	2,758	2,931	173
2021/22	2,800	2,976	176
2022/23	2,843	3,022	179
2023/24	2,887	3,069	182
2024/25	2,932	3,117	185

15.0 Reference: CFT Main Report, page 16 (lines 20-30)

1.15.1 Please explain how the cost-effectiveness analysis incorporated cost and time certainties/uncertainties (see lines 29-30) and describe the cost and timing uncertainties attributed to each of the three cases (i.e., Tier 1, Tier 2 and No Award).

RESPONSE:

The cost-effectiveness analysis incorporated cost and time certainties/uncertainties in the quantitative sense by doing sensitivity analysis with respect to certain variables. Specifically, sensitivities were performed on the timing of the in-service of the 230 kV transmission circuit, the forecasted load deficit on Vancouver Island, the gas/electricity price forecast, and the cost of Mainland generation.

The cost-effective analysis also addressed some factors qualitatively, such as the cost and timing uncertainty of temporary generators relative to the CFT bids, which were firm and legally binding.

Also refer to response to BCUC IR 1.14.1.

15.0 Reference: CFT Main Report, page 16 (lines 20-30)

1.15.2 What was the “cost-effectiveness standard” (see lines 20-22) established for the Tier 1 bids in the CFT?

RESPONSE:

The Tier 1 standard being referenced arose from section 17.3 of the CFT which came into effect with the privative clause amendment made within Addendum 10 issued on 05 March 2004. For Tier 1 portfolios, “if 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”.

To assist it in making this cost effectiveness determination, BC Hydro’s senior management was provided with the following analyses:

- **comparison of CFT portfolios with the VIGP Benchmark**
- **comparison to BC Hydro’s contingency plan options**
- **consideration of cost effectiveness criteria including cost, reliability, dispatchability, timing and location**

16.0 Reference: CFT Main Report, page 17 (lines 2-9 and 22-30)

1.16.1 Please provide tables equivalent to Table 5 showing the supply/demand capacity balance for Vancouver Island for each of the three cases considered in the Cost Effectiveness Analysis. Please include the new 230 kV AC cable in the tables with the timing updated as required to reflect BCTC's response to BCUC request as per Transcript page 310.

RESPONSE:

Table IR 1.16.1 provides the VI capacity balance for all three cases in the cost effectiveness analysis, assuming the 230 kV circuit is in-service by the fall of 2009 (F2010).

Table : BCOAPO 1.16.1 Vancouver Dependable Capacity Supply vs Demand

(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 (450MW)	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 Purchase Contracts (266 MW)	231	250	266	266	266	266	266	266	266	266	266	266
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
Tier 1:												
Duke Point Power				252	252	252	252	252	252	252	252	252
Norske Demand Management				30	40	0	0	0	0	0	0	0
230 kV cables						600	600	600	600	600	600	600
Surplus / Deficit after Power Smart	-35	-19	-19	20	2	532	476	453	418	384	351	313
Tier 2:												
Tier 2 Total				122	122	122	122	122	122	122	122	122
Norske Demand Management				140	140							
Temporary Generators					46							
230 kV cables						600	600	600	600	600	600	600
Surplus / Deficit after Power Smart	-35	-19	-19	0	18	402	346	323	288	254	221	183
No Award:												
Norske Demand Management				140	140							
Temporary Generators				138	161							
230 kV cables						600	600	600	600	600	600	600
Surplus / Deficit after Power Smart	-35	-19	-19	16	11	280	224	201	166	132	99	61

16.0 Reference: CFT Main Report, page 17 (lines 2-9 and 22-30)

1.16.2 Please provide tables equivalent to Table 5 showing the supply/demand energy balance for Vancouver Island for each of the three cases considered in the Cost Effectiveness Analysis. Please include the new 230 kV AC cable in the tables with the timing updated as required to reflect BCTC's response to BCUC request as per Transcript page 310.

RESPONSE:

An energy balance for Vancouver Island is not relevant. The energy requirements of BC Hydro system are addressed on a system basis. Energy resources located on the Vancouver Island contribute to the system supply of energy. The energy requirements of Vancouver Island are not addressed separately from total system energy requirements.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.1 Please confirm that the two electricity price scenarios used 100% and 90% of the unit cost of production for the Tier 1 CFT – excluding the firm gas transportation costs. If not, please describe the basis for the price scenarios.

RESPONSE:

In the cost effectiveness analysis, it was not the electricity price scenarios that were 100% and 90% percent of the cost of the Tier 1 CFT project, excluding the firm gas transportation. Rather, the full annual cost of the Tier 1 CFT project excluding firm gas transportation was used to represent the estimated cost of mainland generation acquired in the "No Award" portfolio. This same cost was applied to the additional Mainland generation added to the Tier 2 portfolios to make the annual energy capability equivalent in all portfolios from 2009 onward.

The Tier 1 CFT cost was based on the EIA gas price forecast. The cost of Mainland generation did not vary when the gas price was varied in the High Gas – Low Electricity Forecast sensitivity analysis, because the generation was not assumed to be gas-fired. Sensitivity analyses were subsequently applied at 100% and 90% of this estimated cost of Mainland generation.

The forecast of electricity prices was used to calculate the value of the annual energy produced in all the portfolios under all sensitivities. It was based on the average of the EIA electricity price forecast based on full cost recovery and the EIA electricity price forecast based on partial cost recovery. See BC Hydro's response to BCUC IR 1.41.2.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.2 Please discuss why it is reasonable to assume for the Base Case (as shown in Table 6) that mainland generation would cost the same as generation constructed on Vancouver Island (excluding firm gas tolls).

RESPONSE:

The Tier 1 outcome of the CFT process was the result of a competitive call for new IPP resources that provided dependable capacity and accompanying energy. There was a strong response to the CFT. Therefore, this CFT is considered representative of the prices that would be offered in a system-wide call for resources that provided dependable capacity and accompanying energy. The cost of gas tolls to Vancouver Island was excluded since that was unique to gas-fired generation located on the Island. BC Hydro tested this assumption by including the scenario in which the cost of Mainland generation was only 90 percent of the cost of Tier 1 project excluding gas tolls.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.3 Was the same mainland electricity price used to evaluate all three cases or were independent prices determined for each case based on the anticipated operation of the mainland generation to meet the additional energy requirements? In either case, please produce a schedule setting out the cost(s) of mainland electricity used for each case and, if different forecasts were used for each case, please explain the factors leading to the differences. (Note: If the absolute values can not be provided for reasons of confidentiality please explain why this is the case and provide the price differential for the three cases)

RESPONSE:

The costs in each portfolio were the costs specific to the resources in that portfolio. The *cost* of Mainland generation in the "No Award" case (approximately 1800 GWh/year) and in the "Tier 2" case (approximately 600 GWh/year) was based on the cost of the Tier 1 project, excluding tolls. Effectively the same unit cost (price) was used for Mainland generation in the two portfolios that have mainland generation in them. Mainland generation is included in the "No Award" portfolio and the "Tier 2 Portfolio" so that each portfolio has the same annual energy volume every year from 2009 onward.

However, in all three cases the *value* of the annual energy was calculated based on the EIA price forecast. For each portfolio, the present value of annual costs was calculated net of the market value of the energy produced annually.

In this simplified cost-effectiveness analysis it was necessary to make all portfolios equivalent in annual energy from 2009 so that the analysis could be done in isolation of the operation of the rest of the system. This was the year in which new energy resources were required for the system in the "No Award" portfolio.

The total annual cost of the Mainland generation in the "Tier 2" portfolio was equal to the total annual cost of the Mainland generation in the "No Award" portfolio, scaled in each year by the ratio of (Tier 1 energy minus Tier 2 energy) to (Tier 1 energy). This is approximately (1800-600)/1800 or 67 percent, based on the ratio that was applied to determine the amount of Mainland generation needed in the Tier 2 portfolio.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.4 Please confirm the basis for the electricity price forecast used to value energy losses and energy volume differences prior to 2010. Was it an EIA electricity price forecast (as suggested in Appendix J, page 2 – last paragraph)? If so, please provide the forecast. Alternatively, was it a BCH-prepared electricity price forecast based on the EIA gas price forecast (as suggested in Appendix J, page 2 – first paragraph)?

RESPONSE:

The electricity price forecast used to value the energy losses and energy volumes in all portfolios was the average of the two EIA electricity price forecasts used in the Quantitative Evaluation Methodology. For a table of the forecast prices, please see the response to BCUC IR 1.24.1.

This average price forecast was used in all years to value losses and energy volumes, not just the "years prior to 2010". However, with respect to the latter, the portfolios were constructed to have the same annual energy in all portfolios from 2009 onward.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.5 Please explain why a different approach to valuing electricity energy differences between the three cases was used for the period prior to 2010 (which uses electricity price forecasts corresponding to the EIA gas price forecast - Appendix J, page 3) versus after 2010 (which uses the uses prices based on a Tier 1 CFT plant – Appendix J, page 2).

RESPONSE:

For each portfolio, the annual cost of its generation was calculated and then the annual value of that generation was calculated based on the electricity price forecast.

The *cost* of the alternative Mainland generation that "came into service" as of 2009 was based on the cost of the Tier 1 CFT plant less gas tolls. In one sensitivity analysis this cost was reduced by 10 percent. This estimated cost of Mainland generation did not vary with gas price assumption, because it was not assumed to be gas-fired.

The same electricity price forecast was used to calculate the *value* of the annual energy produced in all portfolios either by CFT projects or the alternative Mainland generation.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.6 Please confirm whether the Base Case shown in Table 6 assumes:

- A new cable in-service date of 2009 – as per page 17 of the CFT Main Report, or
- A new cable in-service date of 2010 – as per Appendix J, page 2 (last paragraph).

RESPONSE:

The Base Case shown in Table 6 assumes the 230 kV transmission circuit is in-service by October 2009, which is the same as the 2010 Cable In-Service (i.e. F2010 or fiscal year ending March 31, 2010) in Attachment A of Appendix J.

Please also see BC Hydro's response to JIESC IR 1.8(a).

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

1.17.7 Attachment A of Appendix J contains a Table setting out the number of required Temporary Generators for each of the three cases. Please indicate the in-service date assumed for the new 230 kV AC cable in preparing the Table. If required, please update the Table to reflect BCTC's response to the BCUC request as per Transcript page 310.

RESPONSE:

Please see BC Hydro's response to BCUC IR 1.14.7.2.

18.0 Reference: CFT Main Report, pages 21-22

1.18.1 Was an incremental rate impact analysis conducted for either the Tier 2 or No Award cases? If so please provide the results in a format similar to Figure 2. If not, please provide a comparable rate impact analysis for the No Award case.

RESPONSE:

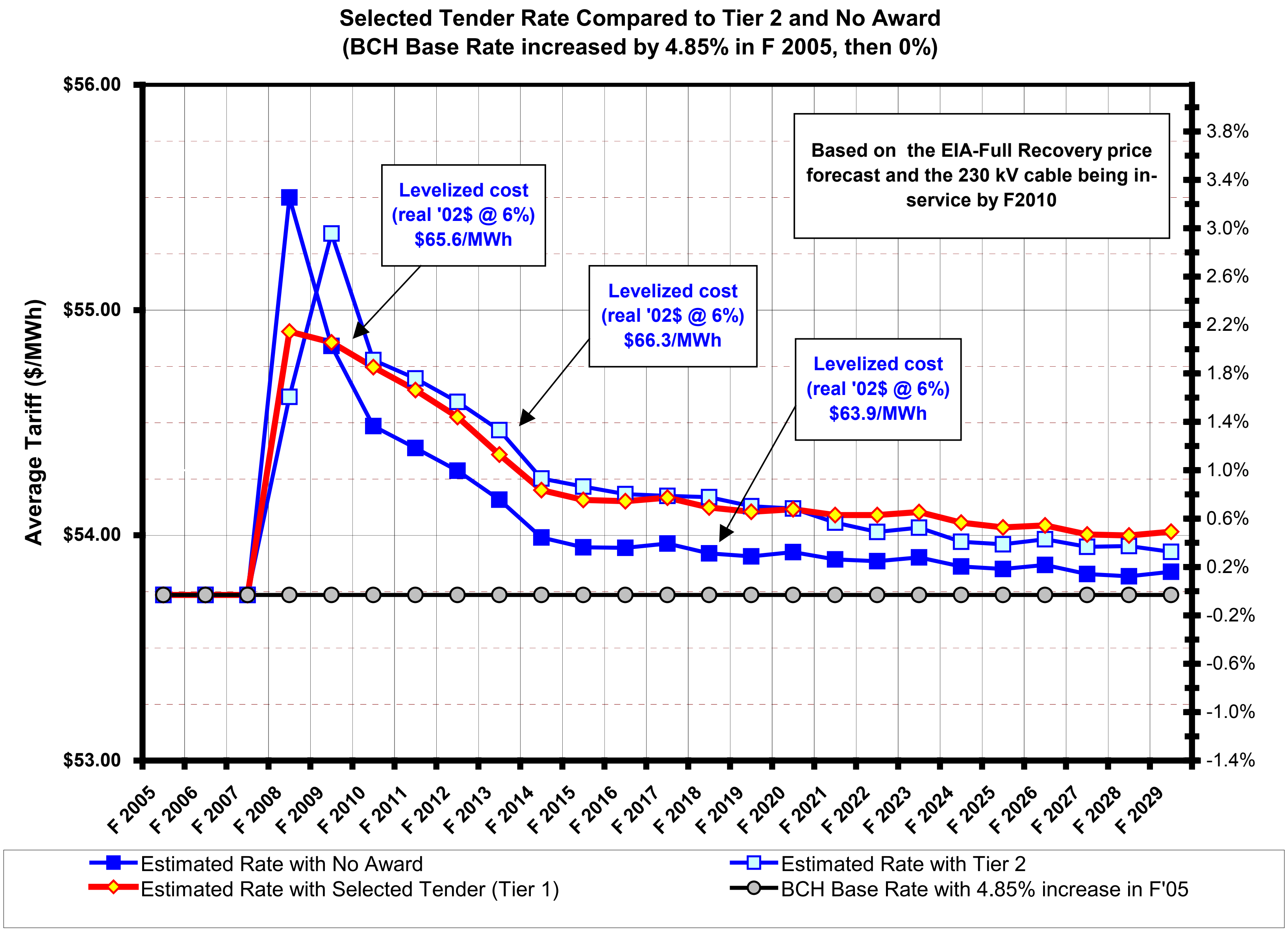
Attached is a chart providing the rate impact analysis for the Tier 1, Tier 2 and No Award scenarios in a format similar to Figure 2 contained in the *Report on the CFT Process*. A summary of the results is presented in the following table:

	First Year Rate Impact	Levelized Cost (Real 2002$ @ 6%)
Tier 1, Selected Tender	**2.18%**	**$65.6/MWh**
Tier 2	**1.64%**	**$66.3/MWh**
No Award	**3.28%**	**$63.9/MWh**

With respect to the rate impact analysis, the following considerations are relevant:

a) The chart does not reflect the cash flow arising from disposal of the VIGP assets, which would occur during calendar 2005. For Tier 1, the sales value of the VIGP assets is $50 million whereas for the Tier 2 and No Award cases, the assumed salvage value is $14 million.

b) If the in-service date of the 230 kV AC cable is delayed beyond F2010, additional bridging supply will be required for the Tier 2 and No Award scenarios resulting in higher costs and additional non-quantitative risks/uncertainties relative to the Tier 1 option.


Selected Tender Rate Compared to Tier 2 and No Award
(BCH Base Rate increased by 4.85% in F 2005, then 0%)
Average Tariff ($/MWh)
$56.00
$55.00
$54.00
$53.00
3.8%
3.4%
3.0%
2.6%
2.2%
1.8%
1.4%
1.0%
0.6%
0.2%
-0.2%
-0.6%
-1.0%
-1.4%
Based on the EIA-Full Recovery price forecast and the 230 kV cable being in-service by F2010
Levelized cost (real '02$ @ 6%) $65.6/MWh
Levelized cost (real '02$ @ 6%) $66.3/MWh
Levelized cost (real '02$ @ 6%) $63.9/MWh
F 2005
F 2006
F 2007
F 2008
F 2009
F 2010
F 2011
F 2012
F 2013
F 2014
F 2015
F 2016
F 2017
F 2018
F 2019
F 2020
F 2021
F 2022
F 2023
F 2024
F 2025
F 2026
F 2027
F 2028
F 2029
Estimated Rate with No Award
Estimated Rate with Tier 2
Estimated Rate with Selected Tender (Tier 1)
BCH Base Rate with 4.85% increase in F'05

19.0 Reference: CFT Main Report, page 24 (lines 11-13)

1.19.1 Has BCH performed any independent assessments regarding the likelihood that Duke Point Power will not meet the scheduled in-service date? If so please, provide.

RESPONSE:

The SEC Technical Subcommittee, which included independent engineering consultants, evaluated the likelihood that each proposed project would meet the Guaranteed COD.

19.0 Reference: CFT Main Report, page 24 (lines 11-13)

1.19.2 What are BCH's contingency plans for Vancouver Island supply in the event of a one-year delay in the in-service date for the Duke Point Power facility?

RESPONSE:

As noted in response to BCUC IR 1.40.2, BC Hydro has identified a number of contingency measures to address supply deficits on Vancouver Island. BC Hydro and BCTC will evaluate Vancouver Island contingency options and activate plans to bridge any capacity shortfall upon completion of the Commission's review of the CFT and on an annual basis thereafter.

19.0 Reference: CFT Main Report, page 24 (lines 11-13)

1.19.3 Are the financial penalties that would be assessed against Duke Point Power for not being in-service for the winter of 2007/08 sufficient to pay the incremental costs associated with the contingency plans BCH would required to implement to maintain the supply/demand balance on Vancouver Island?

RESPONSE:

Financial assurance requirements and liquidated damages were generally based on the cost of establishing alternative temporary generation for a period of six months. However, the damages and financial assurance are less than the full loss to which BC Hydro would be exposed if the facility did not reach COD or subsequently failed to generate. Please also see BC Hydro's response to BCUC IR 2.48.5.

20.0 Reference: CFT Report, Appendix B

1.20.1 Please explain how the “allocation of fuel risk” (see Item 6.2) was considered in the tender evaluation.

RESPONSE:

Please see BC Hydro’s response to BCUC IR 1.17.1.

20.0 Reference: CFT Report, Appendix B

1.20.2 With reference to Item 6.2 and Addendum 10 (Appendix G), how many of the five natural gas projects that were considered in the development of the final 5 portfolios (see Report 4 of the IR, page 13) opted for:

a) No Tolling

b) Partial Tolling

c) Full Tolling?

RESPONSE:

1.20.2 a) None.

1.20.2 b) None.

1.20.2 c) Five.

20.0 Reference: CFT Report, Appendix B

1.20.3 Which Tolling option did Duke Point Power opt for in its bid?

RESPONSE:

Duke Point Power opted for the Full Tolling election.

20.0 Reference: CFT Report, Appendix B

1.20.4 With reference to Item 6.3, in the event that Duke Point opted for either the Partial or Full Tolling option, has BCH received a firm commitment from TGVI with respect the cost of firm transportation?

RESPONSE:

No, BC Hydro has not received a firm commitment from TGVI on gas transportation costs. TGVI has provided tolling cost estimates based on expansion plans for its high pressure transmission system and on the application of current toll design principles for the TGVI system. Please see BC Hydro's response to BCUC IR 1.23.5 for more details.

20.0 Reference: CFT Report, Appendix B

1.20.5 If the answer to 20.4 is “no,” then:

a) How sensitive is the selection of Duke Point Power as the preferred Tier 1 option to changes in the tolls for firm transportation service associated with the project?

b) Please perform a sensitivity analysis of Tier 1 versus Tier 2 versus No Award (as per CFT Main Report, Table 6) assuming a 20% increase in TGVI’s tolls for firm transportation service.

RESPONSE:

1.20.5 a) **From the perspective of the QEM outcome, the selection is insensitive to changes in the firm gas transportation tolls for the Duke Point Power project because every portfolio being evaluated involved a VIGP project.**

The sensitivity of the CFT Cost Effectiveness Analysis to gas tolls was not one of the scenarios evaluated.

1.20.5 b) **This Information Request is out of scope.**

20.0 Reference: CFT Report, Appendix B

1.20.6 With respect to Item 7.6, does BCTC guarantee its Network Upgrade cost estimates? If not, then:

a) How sensitive is the selection of Duke Point Power as the preferred Tier 1 option to changes in the Network Upgrade costs associated with the project?

b) Please perform a sensitivity analysis of Tier 1 versus Tier 2 versus No Award (as per CFT Main Report, Table 6) assuming a 30% increase in Network Upgrade costs for Duke Point Power? (Note: If BCTC guarantees for its costs estimates involve a different ceiling, please substitute the BCTC value in the analyses)

RESPONSE:

1.20.6 a) **BCTC does not guarantee its Network Upgrade cost estimates. From the perspective of the QEM outcome, the selection is insensitive to changes in the estimate for Network Upgrades for the Duke Point Power project because every portfolio being evaluated involved a VIGP project.**

From the perspective of the CFT Cost Effectiveness Analysis, this sensitivity was not evaluated.

1.20.6 b) **This Information Request is out of scope.**

20.0 Reference: CFT Report, Appendix B

1.20.7 With respect to Item 11.3, is the Duke Point Power project dispatchable or must-run? If the former, is it Non-Peaking or Peaking Capacity? If the later, is it must run at Full Capacity or with a Minimum Turndown Capacity?

RESPONSE:

The Duke Point Power project provides 252 MW of dependable capacity as a dispatchable non-peaking capacity project, with a minimum turndown. This means the project can be dispatched off, or at a level anywhere between the minimum turn capacity and the bid capacity. It is not peaking capacity because the tendered ramp-up times are greater than 60 minutes.

21.0 Reference: CFT Report, Appendix H and CFT Main Report, Table 3

1.21.1 With respect to Item 3.4.6, please provide a schedule setting out the derivation of 8% as BCH's current weighted average cost of capital.

RESPONSE:

The Call For Tenders evaluation methodology uses an 8% discount rate. This is consistent with the recent BC Hydro Revenue Requirements submission.

21.0 Reference: CFT Report, Appendix H and CFT Main Report, Table 3

1.21.2 Please provide the total NPV calculated for the Duke Point Power Project broken down into the following cost components:

- Capital Charges
- OM&A Charges
- Energy Margin – broken down to separate the portion based on the average Forecast Electricity Prices and the portion based on Tender Variable costs.
- Start-Up Costs
- Firm Gas Transportation (if Partial or Full Tolling)
- Gas Costs (if Full Tolling)
- Network Upgrade Costs
- VIGP Credit

(Note: If the above components do not account for the full NPV of the Duke Point Power portfolio's NPV please add the missing elements as separate items)

RESPONSE:

This Information Request is out of scope.

22.0 Reference: Exhibit B-6, Duke Point Power Electricity Purchase Agreement

1.22.1 Based on the terms of this agreement and the assumptions regarding the operation of Duke Point Power's generation used in the Tender/Portfolio evaluations, please provide a schedule setting out for the duration of the agreement:

a) the annual amount energy BCH expects to purchase from Duke Point Power over the duration of the agreement, and

b) the annual amounts payable to Duke Point Power for that energy in total and broken down into the following components:

- the CC Payment
- the OMC Payment
- the EC Payment
- the Start-Up Payment, and
- Availability Adjustment (if assumed applicable).

RESPONSE:

1.22.1 a) This information was filed on a confidential basis with the BCUC in BC Hydro's response to BCUC IR 1.33.2

1.22.1 b) This information was filed on a confidential basis with the BCUC in BC Hydro's response to BCUC IR 1.9.0, 1.14.2 and 1.14.4

22.0 Reference: Exhibit B-6, Duke Point Power Electricity Purchase Agreement

1.22.2 Based on the terms of this agreement and the assumptions regarding the cost of gas and operation of Duke Point Power's generation used in the Tender/Portfolio evaluations, please provide a schedule setting out for the duration of the agreement:

a) the annual natural gas requirements of the Duke Point Power generation facility,

b) the annual amounts payable for by BCH for the natural gas supplied to the Duke Point Facility (assuming Full Tolling),

c) the annual amounts payable by BCH to TGVI for gas transportation service to the facility (assuming Full or Partial Tolling), and

d) the annual amounts payable by BCH to other parties for gas transportation service to the facility (assuming Full or Partial Tolling).

RESPONSE:

1.22.2 a) **Please see BC Hydro's response to JIESC IR 1.7.0 (c).~~This information was filed on a confidential basis with the BCUC in BC Hydro's response to BCUC IR 1.9~~**

1.22.2 b) **This Information Request is out of scope.**

1.22.2 c) **Please see BC Hydro's response to BCUC IR 2.47.1.**

1.22.2 d) **The CFT evaluation assumed that all gas for CFT full or partial tolling projects would be sourced at Huntingdon/Sumas. Consequently, no costs for gas transportation service by other parties (i.e. other than TGVI) were assumed in the evaluation.**

22.0 Reference: Exhibit B-6, Duke Point Power Electricity Purchase Agreement

1.22.3 In the event that Duke Point Power has elected for either Full Tolling or Partial Tolling, where does the agreement address BCH's obligations with respect to gas transport (and commodity supply, if applicable)?

RESPONSE:

DPPLP has elected Full Tolling. BC Hydro's resulting obligations with respect to gas commodity and transportation are found at various places throughout the executed EPA, a redacted copy of which has been filed with the Commission.

These provisions are most easily referenced in Appendix 8 of the Final Form (*pro forma*) EPA, also filed with the Commission. Part B of Appendix 8 includes all the provisions that would apply in the event a bidder elected Full Tolling, as DPPLP has done. In preparing the execution version of the EPA, the various alterations dictated by Part B of Appendix 8 were made in the main body of the EPA (and elsewhere), and Appendix 8 was removed from the document.