1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(a) Provide the variable cost data and calculations in Excel format in a manner that allows the assumptions to be examined and sensitivity analysis to be undertaken to evaluate the Energy Margin and variable costs.

RESPONSE:

The evaluation Tendersheet released to the BCUC on 02 December 2004 and to the JIESC on 03 December 2004 is the Excel spreadsheet used in the Quantitative Evaluation Methodology. This allows the calculation of the Energy Margin, variable costs and associated sensitivities.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(b) Confirm that the gas and electricity prices in the models provided to Intervenors reflect the prices used in the final evaluations.

RESPONSE:

Yes.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(c) Explain how seasonal gas price variations and volatility were reflected in the analysis.

RESPONSE:

Gas and electricity price seasonality was reflected in the profile of the gas and electricity forecasts by using a simplified generation dispatch model (the Tendersheet) that simulated plant operations on a monthly time frame (heavy and light load hours).

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(d) Provide a copy of the source documents or source files for gas (EIA) and electricity price forecasts.

RESPONSE:

Please refer to the responses to BCUC Information Requests 1.24.1 and 1.24.3.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(e) Provide a comparison the 5 gas price scenarios to the EIA Reference Case in printed and spreadsheet format.

RESPONSE:

For a spreadsheet-based version of the natural gas prices used in the Quantitative Evaluation, refer to the Tendersheet evaluation model as provided to the JIESC. All gas price forecasts are included in the Tendersheet under the spreadsheet tab: "Market".

The gas price forecasts are representative of the value of natural gas at Sumas/Huntingdon. All forecasts are in nominal (current) dollars.

For the natural gas prices in printed format, refer to BC Hydro's response to BCUC IR 1.24.3.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(f) Explain how the electricity prices were determined for each of the 25 years of the evaluation.

RESPONSE:

Please refer to Section 3.4 of the Quantitative Evaluation Methodology document posted on the BC Hydro website at http://www.bchydro.com/rx_files/info/info14505.pdf.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(g) If the electricity price is based on a spark spread, provide the assumptions, including the assumed market heat rate for each year of the evaluation.

RESPONSE:

The electricity price is not derived from a spark spread. Please see the response to JIESC IR 1.1.0 (f).

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(h) Identify where BC Hydro has altered the gas or electricity price forecasts provided by third parties or used averages or weighted data.

(i) Provide an explanation of why the data was altered and what effect it has on the analysis.

(ii) Provide examples of how the EIA forecast was adjusted for basis differentials and exchange rates for each year of the forecast.

RESPONSE:

Please see the responses to JIESC IR 1.1.0(f) and BCUC IR 1.26.2.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(i) Provide a comparison of the Duke Point Power heat rate to the heat rate of more current CCGT technologies, cogeneration and anticipated future CCGT generation technologies.

RESPONSE:

As noted in response to BCUC IR 1.31.1, the Duke Point Power Project proposes to use an “F” class gas turbine along with the existing Fuji Electric steam turbine generator owned by BC Hydro.

For a comparison of this CCGT configuration against other related technologies, please see VIGP Application, Appendices E, F and G. The specific heat rate provided by Duke Point Power as part of their tendered has been filed in confidence with the BCUC in response to BCUC IR 1.9.3.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(j) Provide a layman's description of the "100% Capital Cost Recovery" scenario and the "25% Capital Cost Recovery" scenario and what they mean in terms of Capacity Factor and Energy Margin.

RESPONSE:

Please see response to JIESC IR 1.1.0(f).

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(k) Provide a monthly “back-cast” analysis of the Energy Margin using the actual gas prices and hourly electricity prices assuming that the Duke Point Plant was operating for the period December, 2002 to November, 2004 or for the most recent 24 month period for which price data is available.

RESPONSE:

This Information Request is out of scope.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(I) Provide the net present value of the incremental cash flows assuming that Duke Point Power does not run to meet either capacity or energy requirements after the 230 kV transmission line is installed in F2009.

RESPONSE:

BC Hydro did not analyze the scenario where the Duke Point Power project does not run at all after the 230 kV transmission circuit is installed.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(m) Provide the annual cost of:

(i) Keeping the Duke Point Plant ready to run.

(ii) Mothballing the Duke Point Plant.

RESPONSE:

The information requested is confidential.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(n) What is the generally accepted reliability of the Frame F7A CCGT:

(i) By the supplier,

(ii) In the industry generally?

RESPONSE:

According to information provided by Duke Point Power, reliability, defined as 1-unplanned outages, for industry standard “F” class design plants averages 98% as a function of annual operating factor. The Duke Point Power Project’s reliability is estimated at 98.6%.

Please also see BC Hydro’s response to BCUC IR 1.33.3.

1.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

1.1.0(o) If the Duke Point Plant is unable to maintain a 97% reliability, is Pristine Power:

(i) In breach of the contract, or

(ii) Subject to defined payments?

RESPONSE:

If the Seller fails to achieve monthly availability of 97%, calculated in accordance with s. 3.5 of Appendix 3 of the EPA, the Seller will be subject to an Availability Adjustment that is equal to $250/MW x Demonstrated Capacity, for every percentage point of availability shortfall below 97%. Poor availability during a prolonged period of time may also trigger termination (Definition 129 of Appendix 1 of the EPA).

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(a) Confirm that BC Hydro may be required to purchase gas at Station 2 and assume transportation costs from Station 2 to Huntingdon-Sumas.

RESPONSE:

BC Hydro believes that Huntingdon-Sumas is sufficiently liquid for the purposes of forecasting gas prices and executing transactions in the market.

BC Hydro could purchase gas at Huntingdon-Sumas or it could acquire additional gas transportation from Station 2 to Huntingdon-Sumas, but it would not be required to do so.

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(b) Did BC Hydro prepare or obtain a forecast of Station 2 gas prices for the CFT analysis or for gas supply management purposes? If yes, provide the forecast in Excel spreadsheet format with comparable Huntingdon-Sumas and EIA prices.

RESPONSE:

BC Hydro did not prepare a forecast of Station 2 gas prices for the purpose of the CFT. At various times, BC Hydro has prepared forecasts of Station 2 pricing for gas supply management purposes. BC Hydro does not have a forecast of Station 2 prices prepared on a comparable basis with the gas forecasts used in the CFT.

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(c) Confirm that gas at Station 2 trades in $C.

RESPONSE:

Confirmed.

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(d) Provide the annual forecast fixed and variable unit and total cost (fuel, MFT) of natural gas purchased at Station 2 compared to the assumed fixed and variable unit and total cost at Huntingdon-Sumas as used in the CFT analysis.

(i) Explain how the Huntingdon-Sumas gas price relates to the EIA Reference Case.

(ii) Explain how the Station 2 gas price relates to the EIA Reference Case.

RESPONSE:

Please see the response to JIESC IR 1.2 (b).

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(e) Outline and explain the transportation and gas cost mitigation strategy for gas delivery at the Huntingdon-Sumas hub and delivery point.

RESPONSE:

Please see the response to BCUC IR 1.23.2.

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(f) Quantify and explain how the change in trading hub and delivery point to Station 2 would affect the net portfolio cost and mitigation strategy of BC Hydro.

RESPONSE:

BC Hydro would only shift its gas purchases to Station 2 if that result would lower overall gas purchasing costs or risk.

2.0 Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

1.2.0(g) Provide all of the inflation rates and exchange rates used in the CFT analysis and an explanation of how and to what numbers the inflation rates were applied.

RESPONSE:

A calendar inflation rate of 2.1% and an exchange rate of $0.771 CAD/USD were used in the CFT analysis.

Inflation rates were used in the conversion of the Energy Information Administration natural gas forecast prices from real dollars to nominal dollars.

Exchange rates were used in the conversion of Energy Information Administration natural gas forecast prices from US to Canadian dollars.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(a) Provide a copy of the correspondence from TGVI setting out the forecast fixed and variable gas transportation costs used in the CFT evaluation.

RESPONSE:

Please see the response to BCUC IR 1.23.5.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(b) Provide the effect of using a 4.6-5.0% system gas ratio on the TGVI system as set out in the attachment vs. the 2.5% system gas ratio used in the evaluation.

RESPONSE:

The average system fuel ratio used for the CFT evaluation was 4.9%, based on data provided by TGVI. The original system gas estimate of 2.5%, stated at page 15 of Appendix H, Quantitative Evaluation Methodology, was an initial value used to test the QEM model. However, 2.5% was not used in the final evaluation of the submitted tenders.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(c) Confirm that BC Hydro currently pays a toll equal to 1.25 times the allocated cost of service (including RDDA recovery) and that TGVI has assumed in CPCN IR responses that BC Hydro will pay a gas transportation toll of 1.25 times the allocated unit cost of service, which equates to a toll in the range of $1.00 to $1.07 per GJ at a 100% load factor.

RESPONSE:

BC Hydro currently pays a toll for gas delivery service to ICP equal to 1.25 times the allocated cost of service (including RDDA recovery). In TGVI's CPCN application for a proposed LNG storage facility, TGVI has shown "illustrative tolls" based on allocated unit cost of service multiplied by 1.25. TGVI has provided various estimates of these tolls for different portfolios and cost allocation assumptions. TGVI's evidence in the LNG proceeding (Exhibit B-11) shows illustrative tolls in the range of $0.85 to $1.19 per GJ for the LNG portfolio if costs and mitigating revenues are allocated on a system-wide basis. TGVI also shows illustrative tolls of $0.98 to 1.18 per GJ for the LNG portfolio if LNG costs and mitigating revenues benefits are allocated to the distribution system.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(d) Provide the assumed gas transportation contract demand on TGVI that is required to serve Duke Point Power and ICP.

RESPONSE:

The firm contract demands assumed for ICP and Duke Point are 45 TJ/day and 44.6 TJ/day, respectively.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(e) Confirm that if BC Hydro did contract for less than the 90 TJ/d as assumed by TGVI, it is likely that the unit toll to BC Hydro would increase proportionately.

RESPONSE:

BC Hydro is unable to confirm this statement. If BC Hydro were to contract for less than 90 TJ/day, BC Hydro assumes that TGVI would scale down its expansion plans. Then, all other things being equal, the toll determination would be based on dividing a smaller pool of costs by a reduced amount of billing determinants. BC Hydro does not know whether the resulting calculation would result in higher or lower toll relative to a BC Hydro contract demand of 90 TJ/day.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(f) If TGVI was unable to recover its allocated revenue requirements from core customers, in BC Hydro's experience, is it probable that BC Hydro and other transmission (HPTS) shippers would pay higher tolls to ensure that TGVI recovered its total revenue requirements?

(i) How has BC Hydro factored the TGVI toll risk into the evaluation?

RESPONSE:

With the current soft cap mechanism in place, any shortfall in TGVI's core market revenues will flow to the revenue deficiency deferral account (RDDA) for later recovery. Allocation of RDDA to shippers and other customer classes is a matter for the Commission to determine within the framework of the 1995 Special Direction.

3.0 Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

1.3.0(g) Provide the forecast annual firm and interruptible gas volume to the Duke Point project and to ICP.

RESPONSE:

Assuming an average annual capacity factor of 90% for each plant, the annual firm gas volume required at each plant will be approximately 14.8 PJ per year. The interruptible gas volumes are difficult to estimate, but will likely be in the order of 0.6 PJ per year for each plant.

4.0 Reference: Report, Page 17, Report, Appendix J, Page 2;

Explanation: BC Hydro has assumed that curtailment and temporary generation would be required for 240 hours.

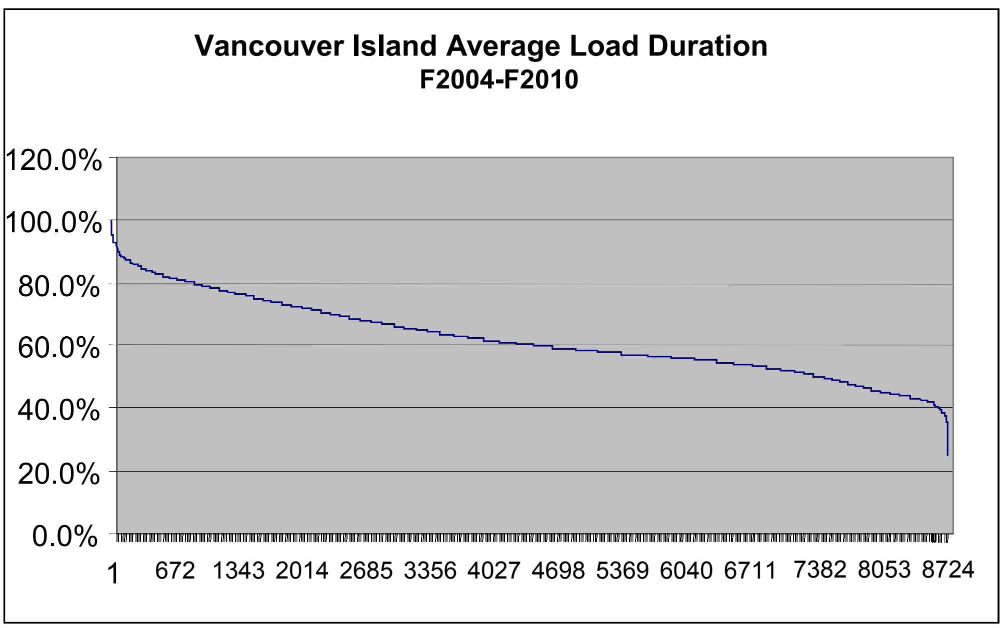
1.4.0(a) Provide the load duration curves for 2004 to 2010 to support the hours required.

RESPONSE:

BC Hydro does not produce a peak forecast on an hourly basis, so a forecast load duration curve is not available. Figure IR 1.4.0(a) provides a load duration curve for Vancouver Island based on an average over the last five years of actual data.

Please also see responses to BCUC IRs 1.15.5 and 2.69.7 for cost sensitivity of temporary generation to operating hours and rationale for the estimated operating hours.

Figure IR 1.4.0(a)



4.0 Reference: Report, Page 17, Report, Appendix J, Page 2;

Explanation: BC Hydro has assumed that curtailment and temporary generation would be required for 240 hours.

1.4.0(b) Provide any CFT correspondence or Q&As with potential proponents identifying hours or days of operation required for peaking facilities, siting of peaking facilities including contacting BC Hydro and availability of interruptible gas transportation capacity from TGVI, with dates.

RESPONSE:

BC Hydro is not aware of any such correspondence.

4.0 Reference: Report, Page 17, Report, Appendix J, Page 2;

Explanation: BC Hydro has assumed that curtailment and temporary generation would be required for 240 hours.

1.4.0(c) Provide any correspondence or Q&As with potential proponents identifying hours or days of curtailment required, location restrictions of curtailment and notice period for curtailment.

RESPONSE:

BC Hydro is not aware of any such correspondence.

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(a) Provide the average capacity factor assumed for Duke Point Power.

RESPONSE:

~~**This information was filed on a confidential basis with the BCUC in response to BCUC IR 1.9.3.**~~

<u>**The capacity factor is not assumed; it is derived from the dispatch modelling in the Quantitative Evaluation Methodology. The average modelled capacity factor for the Duke Point Power plant over the Initial Term is 81.8 percent.**</u>

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(b) Provide information available to BC Hydro that provides capacity and reliability factors for CCGT plants in North America.

RESPONSE:

Please see the response to BCUC IR 1.44.2 and Appendix G of VIEC's CPCN Application for the VIGP.

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(c) Provide the capacity factor experience of Frame 7FA CCGT generation in NA for each of the last 2 years.

RESPONSE:

BC Hydro does not have this information.

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(d) Confirm that capacity factors of a generator are in part a function of market heat rate and that directionally, a more efficient generator will run at a higher capacity factor than a less efficient generator.

RESPONSE:

Confirmed.

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(e) Confirm that new CCGT generation technologies have a higher efficiency than older generation and that the gap would be expected to widen over time as more efficient generation is brought on line.

RESPONSE:

CCGT heat rates, a measure of efficiency, have improved over time. However, the rate of change of gas-fired generation heat rates has slowed. Changes are now based on incremental refinements of this technology. F-class CCGT technology is widely used and specified for new installations.

5.0 Reference: Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power.

1.5.0(f) How has BC Hydro factored the market risk such as that experienced by existing gas fired generation into the CFT evaluation?

RESPONSE:

The Vancouver Island Call for Tenders was run to meet the dependable capacity needs of Vancouver Island. The Duke Point Power tender has been selected as the most cost-effective way for BC Hydro to obtain this.

With respect to natural gas market price risk, please see the response to BCUC Information Request 1.17.1.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(a) Provide the transmission upgrade costs applied to the Tier 2 (150 MW) option.

RESPONSE:

This information was filed on a confidential basis with the BCUC in response to BCUC IR 1.9.3.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(b) Provide a detailed description of the Tier 2 resources totalling 122 MW.

RESPONSE:

There are two Tier 2 projects: a 47 MW gas-fired dispatchable peaking plant, and a 75 MW biomass-fired non-dispatchable plant.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(c) Did BC Hydro consider the option of Tier 2 and contingency as an alternative?

(i) Provide the NPV of a Tier 2 and contingency option in the format of Table 6 and Appendix J.

RESPONSE:

The “Tier 2 award” described in the Cost-Effectiveness Analysis included the costs of contingency measures required to make up the supply shortfall between Vancouver Island’s expected load requirements and the supply provided by the Tier 2 projects. While BC Hydro cannot provide the total NPV costs for confidentiality reasons, the relative costs between the Tier 1 award, Tier 2 award and no award are summarized in Table 6 and Appendix J.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(d) When BC Hydro revised the VI demand forecast, why did BC Hydro not change the CFT?

RESPONSE:

Higher capacity requirements were identified for up to 150 MW more than the BCUC-determined gap as a result of the January 5, 2004 peak experience and because of the 2003 peak load forecast that was filed in December 2003 with the Revenue Requirement application.

BC Hydro considered two options:

(a) raising the minimum portfolio requirement; and

(b) considering contingency options that could bridge between 150 and 300MW.

The first option was rejected because it was not in alignment with the BCUC direction. Accordingly, BC Hydro accepted the latter course.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(e) Provide copies of the presentations to Senior Management in mid-October and the additional analysis provided to Senior Management.

RESPONSE:

Presentations provided to senior management include the CFT Portfolio Spreadsheets that have been provided to the BCUC in confidence (see BC Hydro response to BCUC IR 1.9.4), the cost-effectiveness results as summarized in Table 6 of the CFT Report,, and the following attachment, partially redacted on the basis of confidentiality or a legal privilege.

Results

- Competition saved $50 - $110 M compared to BCH's VIGP option (assuming gas @ $5/GJ CDN and expected in-service date)
- For Tier 1 (reliable, date certain supply)
  - premium of $7 M over Tier 2
  - premium of $90 M over "no CFT" but 140 MW of Temp Gen
- At $7/GJ CDN gas price and expected in-service:
  - premium of $26 M over Tier 2
  - premium of $78 M over "no CFT" but 140 MW of Temp Gen
- However, if 1 year delay:
  - premium of $22 M over Tier 2
  - premium of $47 M over "no CFT"

Key Observations

- Compared to March analysis; directionally consistent
  - However, differential between Tier 2 and Tier 1 has collapsed
- Pay a premium for reliable date certain supply of between $7 M and $26 Million, in best case cable timing, depending on gas forecast
  - Tier 2 and no CFT are less reliable
    - Under Tier 2: [redacted] evaluated as moderate TX risk
    - No CFT and delay in cables under Tier 2 assume significant volumes of Temp Gen with risks of permiting and cost escaltion
- Other considerations [redacted]

Approach to Analysis

- Without CFT, system requires energy and capacity in 2010 or earlier
- So comparison involves advancing supply on VI relative to mainland with similar capacity and energy balances
- For high gas price scenarios - assumption is limited dispatch of CCGT and replacement with market proxy resource at EIA price

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(f) Provide the details of any disqualification of bidders and explain why the reasons for disqualification were considered material.

(i) Were the reasons for disqualification potentially as a result of BC Hydro changing the terms or schedule of the CFT?

RESPONSE:

This Information Request is out of scope.

6.0 Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

1.6.0(g) Did the disqualifications alter the Tier 2 capacity options available to BC Hydro?

RESPONSE:

Yes.

7.0 Reference: Not Applicable;

Explanation: Information is required about the total capital expenditures for the Duke Point Power project by all companies and total forecast payments by BC Hydro related to the Duke Point generation.

1.7.0(a) Provide the forecast capital costs in as spent dollars as follows:

(i) BC Hydro

(ii) BCTC

(iii) Terasen Gas Vancouver Island

RESPONSE:

(i) BC Hydro will not be incurring any capital costs on the Duke Point Power project on a go forward basis.

(ii) BC Hydro received an estimate of network upgrades, for each CFT portfolio (including the Duke Point Power portfolio), from BCTC. This information was received on a confidential basis.

(iii) BC Hydro received an estimate of the annual gas transportation costs, for each CFT portfolio, from Terasen Gas Vancouver Island Inc.

For further information, please see the response to BCUC IR 1.23.5.

7.0 Reference: Not Applicable;

Explanation: Information is required about the total capital expenditures for the Duke Point Power project by all companies and total forecast payments by BC Hydro related to the Duke Point generation.

1.7.0(b) Provide the total payments in as spent dollars over the forecast 25 year term of the EPA broken down as follows:

(i) Duke Point Power

(ii) Terasen Gas Vancouver Island

(iii) Terasen Gas

(iv) Duke/Westcoast Energy

(v) Gas Supply

(vi) Sales Tax and Motor Fuel Tax

(vii) Electricity transmission other than BCTC

RESPONSE:

(i) This information was filed confidentially with the BCUC in response to BCUC IR 1.9.3.

(ii) The total payments to Terasen Gas Vancouver Island were estimated to be $325,796 in as-spent dollars or $131,598 (NPV, 2006 dollars).

(iii) The total payments to Terasen Gas were estimated to be zero.

(iv) The total payments (on a go forward basis) to Duke/Westcoast Energy were assumed to be zero.

~~(v)This information is confidential.~~

(v) Please see BC Hydro's response to JIESC IR 1.7.0 (c).

(vi) The total payments for Sales Tax and Motor Fuel Tax were included in the gas costs.

(vii) The total payments for electricity transmission other than BCTC were assumed to be zero.

7.0 Reference: Not Applicable;

Explanation: Information is required about the total capital expenditures for the Duke Point Power project by all companies and total forecast payments by BC Hydro related to the Duke Point generation.

1.7.0(c) Provide the total fixed charges and total variable charges in as spent (nominal) dollars by year for 25 years.

RESPONSE:

~~**The annual information pertaining to Duke Point Power and to Gas Supply was filed confidentially with the BCUC in response to BCUC IR 1.9.3.**~~

~~**For further information pertaining to Terasen Gas Vancouver Island Inc., please see the response to BCUC IR 1.23.5.**~~

Please see spreadsheet attached.

JIESC IR 1.7.0 c (in CDN Millions)

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Dispatched Energy (GWh)	518	1,260	1,468	1,567	1,850	1,850	1,775	1,894	1,880	1,765	1,880	1,880
CC Payment	$ 24	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36
OMC Payment	$ 6	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10	$ 10	$ 10
EC Payment	$ 2	$ 4	$ 4	$ 5	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 7	$ 7
Start Up Payment	N/A											
Availability Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Dispatched Energy (GWh)												
Full Recovery Scenario	518	1260	1468	1567	2022	2022	1983	2109	2082	1963	2082	2082
Partial Recovery Scenario	518	1260	1468	1567	1679	1679	1567	1679	1679	1567	1679	1679
Average	518	1260	1468	1567	1850	1850	1775	1894	1880	1765	1880	1880
Gas Consumption (TJ)												
Full Recovery Scenario	4060	10023	11576	12256	15793	15793	15330	16305	16143	15209	16143	16143
Partial Recovery Scenario	4060	10023	11576	12256	13147	13147	12256	13147	13147	12256	13147	13147
Average	4060	10023	11576	12256	14470	14470	13793	14726	14645	13732	14645	14645
Cost of Gas ($000)												
Full Recovery Scenario	$17,482	$46,854	$53,503	$58,197	$83,201	$89,595	$93,644	$103,377	$109,355	$106,462	$115,153	$115,838
Partial Recovery Scenario	$17,482	$46,854	$53,503	$58,197	$66,784	$72,106	$72,411	$80,852	$86,488	$83,282	$91,210	$91,768
Average	$17,482	$46,854	$53,503	$58,197	$74,993	$80,850	$83,028	$92,115	$97,922	$94,872	$103,181	$103,803
Average Cost of Gas ($/GJ)												
Full Recovery Scenario	$4.31	$4.67	$4.62	$4.75	$5.27	$5.67	$6.11	$6.34	$6.77	$7.00	$7.13	$7.18
Partial Recovery Scenario	$4.31	$4.67	$4.62	$4.75	$5.08	$5.48	$5.91	$6.15	$6.58	$6.80	$6.94	$6.98
Average	$4.31	$4.67	$4.62	$4.75	$5.18	$5.59	$6.02	$6.26	$6.69	$6.91	$7.05	$7.09

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1,765	1,866	1,866	1,821	1,933	1,947	1,910	2,006	2,006	1,898	2,006	2,006	1,898	673
$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 12
$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 5
$ 7	$ 7	$ 7	$ 7	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 3
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1963	2053	2053	1941	2053	2053	1941	2053	2053	1941	2053	2053	1941	703
1567	1679	1679	1701	1813	1841	1878	1960	1960	1856	1960	1960	1856	642
1765	1866	1866	1821	1933	1947	1910	2006	2006	1898	2006	2006	1898	673

15209	15975	15975	15083	15975	15975	15083	15975	15975	15083	15975	15975	15083	5438
12256	13147	13147	13342	14233	14401	14717	15435	15435	14587	15435	15435	14587	5082
13732	14561	14561	14212	15104	15188	14900	15705	15705	14835	15705	15705	14835	5260

$110,642	$122,786	$130,524	$125,351	$135,155	$137,776	$132,840	$142,659	$145,147	$139,838	$150,123	$152,612	$146,886	$56,744
$86,651	$98,406	$104,775	$109,309	$118,801	$122,741	$129,525	$137,805	$140,209	$135,204	$145,018	$147,422	$142,020	$53,103
$98,646	$110,596	$117,650	$117,330	$126,978	$130,258	$131,182	$140,232	$142,678	$137,521	$147,571	$150,017	$144,453	$54,924

$7.27	$7.69	$8.17	$8.31	$8.46	$8.62	$8.81	$8.93	$9.09	$9.27	$9.40	$9.55	$9.74	$10.44
$7.07	$7.48	$7.97	$8.19	$8.35	$8.52	$8.80	$8.93	$9.08	$9.27	$9.40	$9.55	$9.74	$10.45
$7.18	$7.60	$8.08	$8.26	$8.41	$8.58	$8.80	$8.93	$9.09	$9.27	$9.40	$9.55	$9.74	$10.44

8.0 Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

1.8.0(a) Explain the differences in the 230 kV in-service date.

RESPONSE:

BCTC is proceeding with the definition phase of the Vancouver Island Transmission Reinforcement Project to meet an October 2008 in-service date based on BC Hydro's load forecast for Vancouver Island, as set out in the 2004 IEP and the condition of the HVDC system. This in-service date is equivalent to the F2009 in-service date referenced in the CFT Report.

Preserving the earliest in-service date does not imply that the Vancouver Island Reinforcement Project has a certain date. There are a number of unknown variables, such as the extent, duration and scope of First Nations and public consultation processes and Canadian and US permit application approval processes. Any circumstance that causes even a small delay in the October 2008 in-service date would require BC Hydro to implement contingency measures to ensure Vancouver Island's 2007/08 winter peak requirements are met.

The Cost-Effectiveness Analysis reflects a range of potential in-service dates for the 230 kV AC transmission system, from F2009 (ie, October 2008) to F2014. The F2010 Cable In-Service scenario assumes an earliest in-service date of March 2009.

8.0 Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

1.8.0(b) Provide all studies, reports and other documents relating to the earliest in-service date for the 230 kV transmission to VI.

RESPONSE:

Please see BCTC's responses to BCUC IRs 1.2.2 and 1.3.3.

8.0 Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

1.8.0(c) Provide all studies, reports and other documents relating to the critical path for 230 kV transmission to VI and identify any activities that are subject to delay or possible advancement. Examples include rights of way and approvals.

RESPONSE:

Please see BCTC's responses to BCUC IRs 1.2.2 and 1.3.3.

8.0 Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

1.8.0(d) Provide all studies, reports or other documents relating to the life or reliability extension of the HVDC line to VI that have been undertaken or issued since the VIGP proceedings.

RESPONSE:

This Information Request is out of scope.

8.0 Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

1.8.0(e) If BC Hydro or BCTC have not continued to evaluate the transmission options, explain why.

RESPONSE:

This Information Request is out of scope.

2.9.0 Reference: JIESC IR to BC Hydro 1.1.0(a)

Explanation:

The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

BC Hydro's response to IR 1.1.0(a) states:

The evaluation Tendersheet released to the BCUC on 02 December 2004 and to the JIESC on 03 December 2004 is the Excel spreadsheet used in the Quantitative Evaluation Methodology. This allows the calculation of the Energy Margin, variable costs and associated sensitivities.

Unfortunately, the spreadsheet provided is not populated with the Duke Point EPA data and accordingly the JIESC is not in a position to make such a calculation. Furthermore, if it tried to make such a calculation it is not clear the results would be accepted by BC Hydro due to the number of assumptions that would need to be made.

(a) Provide a copy of the Excel spreadsheet used in the Quantitative Evaluation Methodology populated for the Duke Point EPA. To the extent some information is confidential, it is acceptable to hide and lock the data in those cells or to substitute incorrect or absolute numbers for individual confidential items provided the total annual costs, energy margin and NPV are correct.

RESPONSE:

Duke Point Power Tendersheets for both the EIA Full and Partial recovery forecasts are hereby provided. The numeric string "9999" is entered in those cells that are confidential. Within the Tendersheet, text strings (such as the word: "Confidential") cannot be inserted due to input restrictions BC Hydro had previously included within the Tendersheet logic.
[CD with the Tendersheets mentioned above are not posted on the web, however, available by request.]

(b) Provide the energy margins calculated by BC Hydro in the QEM for the Duke Point EPA by year and in total for both the actual annual amounts and the NPV.

RESPONSE:

Individual year Energy Margins are calculated and displayed in the "Dispatch" tab of each Tendersheet in lines: 428 to 456.