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**VIA FACSIMILE/VIA E-MAIL**
9, 604-623-4407

November 26, 2004

Mr. Richard Stout
Chief Regulatory Officer
British Columbia Hydro and Power Authority
17th Floor, 333 Dunsmuir Street
Vancouver, B.C. V6B 5R3

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

Exhibit No. A-3

Dear Mr. Stout:

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Call for Tenders for Capacity on Vancouver Island ("CFT")
Review of Report on the CFT Process dated November 19, 2004 ("CFT Report")

Attached please find Commission Information Request No. 1 to BC Hydro regarding the CFT Report. Please provide a hard copy and an e-mail file in response.

Yours truly,

*Original signed by:*

Robert J. Pellatt

JBW/rt
Attachment

cc: Mr. Cameron Lusztig
Director, Regulatory Affairs
British Columbia Transmission Corporation
Registered Intervenors

BRITISH COLUMBIA UTILITIES COMMISSION
Commission Information Request No. 1

**British Columbia Hydro and Power Authority ("BC Hydro")**
**Call for Tenders for Capacity on Vancouver Island ("CFT")**
**Report on the CFT Process dated November 19, 2004 ("CFT Report")**

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**1.0 Reference: CFT Report, p. 14, Section 3.2**

The Filing states that the cost-effectiveness analysis was completed using BC Hydro's then most current demand/supply outlook for Vancouver Island and the BC Hydro system.

1.1 What is the elapsed time between the completion of the cost effectiveness analysis and the finalization of the annual electric load forecast for the period 2004/05 to 2024/25?

1.2 Are the numbers used in the cost-effectiveness analysis identical to those presented in the 2004 annual electric load? If not, please list the differences.

**2.0 Reference: CFT Report, p. 14, Section 3.2**

The Filing notes that the 2004 annual electric load forecast will need to be revised upward to reflect the actual rate increase approved by the Commission, thereby increasing the supply deficit on Vancouver Island.

2.1 Is BC Hydro forecasting a supply deficit for energy consumption in the next few years on Vancouver Island?

2.2 Please describe whether the upward revision of the 2004 load forecast will affect only energy demand, or both peak demand and energy demand.

2.3 Please explain on what basis BC Hydro assumes that the electricity demand on peak design days is price sensitive given that distribution peak is most sensitive to temperature and transmission peak is responsive to external market conditions (Reference Appendix I, p.69).

2.4 Is electricity consumption with respect to rate change on Vancouver Island similar to other regions? Please explain.

2.5 In producing the electric load forecast for Vancouver Island, does BC Hydro take into account the "soft cap mechanism" that is in place for the natural gas retail burner tip prices? If yes, how? If no, why not?

2.6 When preparing the 2004 annual electric load forecast for Vancouver Island, did BC Hydro consult with Terasen Gas (Vancouver Island) Inc. ("TGVI") with regard to its demand/supply options or its 2004 Resource Plan? If no, please explain why not. If consultation has taken place, please describe if the outcome of the consultation has resulted in inputs to the BC Hydro load forecasting process for the Vancouver Island region.

**3.0 Reference: CFT Report, p. 16, Section 3.2**

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

3.1 Please provide the section or page number in Appendix J that sets out the basis of economic assumptions and the recalibration of the model. Does BC Hydro mean Appendix I?

3.2 Please compare the economic assumptions that pertain to Vancouver Island energy and peak forecasts with those used in the 2002 Forecast and the 2003 Forecast.

**4.0 Reference: CFT Report, pp. 15-16, Table 5**

Table 5 shows a load forecast of 2,279 MW in F2008 that is 51 MW (2,279-2,228) higher than 2,228 MW in the 2002 Forecast and 78 MW (2,279-2,201) higher than 2,201 MW in the 2003 Forecast.

4.1 To what extent is the increase in F2008 deficit from previous forecasts caused (and mitigated) by the following:
(i) economic factors affecting distribution and transmission customers,
(ii) re-calibrated coefficients from the actual peak load impact in January 2004,
(iii) change in peak forecasting methodology,
(iv) change in design day temperature,
(v) change in transmission and distribution losses,
(vi) Power Smart savings increase or decrease, and
(vi) supply side factors.

4.2 Please repeat the above analysis for 2004/05 and 2013/14 and provide the results for the three discrete years in tabular format.

**5.0 Reference: CFT Report, Appendix I, p. 16**

The 2004 Forecast Report states that the key focus in the current year is to complete implementation of the Forecast Renewal Project which involves building new forecast models that are more accurate, transparent and easier to use than existing models.

5.1 Please describe in detail the deficiencies and shortcomings of the existing models that the Forecast Renewal Project aims to overcome.

**6.0 Reference: CFT Report, Appendix I, p. 18**

6.1 Please confirm that the "decision on the Regulatory Requirements Application of October 29, 2004" should read "…Revenue Requirements Application…"

**7.0 Reference: CFT Report, Appendix I, p. 28, Table 4.2**

7.1 Please explain why the employment growth rate in Year 2023 departs from the 1.7 percent long term growth trend.

7.2 Please explain what contributed to the real GDP weighted growth rates in 2014 and 2015 such that they are higher than the preceding three years.

7.3 Please explain the uneven trend in growth rates for Accounts (For example, the drop to 1.2 percent increase in 2007 from 1.8 percent increase in 2006).

**8.0 Reference: CFT Report, Appendix I, p. 28, Tables 6.1 to 6.5**

8.1 Please provide comparison tables similar to Tables 6.1 to 6.5 for the Vancouver Island regional forecasts. Please provide "With Power Smart" and "Before Power Smart" for each of the above tables.

8.2 Please also provide the main reasons for variances in forecast sales for the various sectors.

8.3 For the actual peak of 10,103 MW recorded for 2003/04, please disaggregate it into distribution peak, transmission peak, wholesale peak and transmission losses.

8.4 Please check if the footnote in Table 6.5 refers to weather normalized actual for 2003/04 rather than 2002/03.

8.5 Please comment if the sub-section headings in Section 6 should be "Forecasts" rather than "Sales" since the numbers could have included distribution and transmission losses.

**9.0 Reference: CFT Report, Appendix I, pp. 41-42**

9.1 Please confirm that the new definition of an average cold day as used on page 41 is the same as average coldest temperature as defined on page 79. How many local weather stations on Vancouver Island are used for the calculation?

9.2 What is the impact of design temperature change from -6.8 to -5.3 degree Celsius on the Reference Peak Forecast With Power Smart for the October 2004 Forecast in Table 6.5?

9.3 What is the impact of design temperature change from -4.4 to -3.6 degrees Celsius on the Annual 2004 Reference Peak Forecast With Power Smart on Vancouver Island?

9.4 Page 41 states that the two year annual forecast comparison for the integrated system total is 134 MW higher in 2004/05. However, according to Table 6.5, the higher 134 MW is for 2003/04 instead of 2004/05. Please confirm that 292 MW is the correct number for 2004/05.

9.5 Please show to what extent the 2007/08 variance of 138 MW is affected by:

(i) new definition of average cold day
(ii) new weather sensitivity data experienced in January 2004
(iii) changes in the 2003 population and employment forecasts

**10.0 Reference: CFT Report, Appendix I, appendix 1, Table A1.1**

10.1 Please describe the time series used in the elasticity analysis.

10.2 Are the electricity and gas prices real or nominal? If the prices have been converted to real prices, which price index (e.g., GDP deflator, CPI) was used? What is the reference date of the real prices?

10.3 What is the rate of increase in gas price compared to rate of increase in electricity prices during the period used in the time-series regression analysis?

10.4 In BC Hydro's opinion, does Model 1 (Without Gas) provide a significant estimated coefficient for log electricity price? Please explain your answer.

**11.0 Reference: CFT Report, Appendix I, appendix 2, Table A2.1**

11.1 Please explain the basis for assuming that income is a good dependent variable for the aggregate peak demand elasticity function.

11.2 In BC Hydro's opinion, is Model 1 (without Gas) providing a significant coefficient for log electricity price? Please explain your answer.

**12.0 Reference: CFT Report, Appendix I, appendix 4, Table A4.1; Section 11 Peak Forecasts**

12.1 Please reconcile the "Actual (MW)" between 1998/99 to 2003/04 in Table A4.1 to the "actuals" between 1998/99 to 2003/04 in Table 6.5 on page 42.

12.2 A footnote (referenced in the heading of the third column) appears to be missing. Please revise the Table with a footnote if applicable.

12.3 Please comment if the data gaps problem encountered in recent years on weather normalizing peak data for each substation (Reference: the Annual 2003 Forecast, p.73) has been largely resolved by better data points.

12.4 What are the risks in relying upon one method for weather adjustments? Please explain the pros and cons of the "bottom-up" and the "top-down" approaches to weather normalization.

12.5 The peak on Vancouver Island reached an all time record peak on January 4, 2004. Please comment if January 4, 2004 could be treated as an ordinary weekend in the daily peak model as described in Equation A4.1.

12.6 If Xmas is redefined to take the value one for the first 12 days beginning December 25 in Equation A4.1, what would be the weather-normalized peak for 2003/04 under this top-down procedure? What would be the new weather-adjusted base year for forecast?

12.7 Based on the redefined Xmas variable as above, what would be the weather adjusted actual for Vancouver Island? Please revise the relevant tables.

**13.0 Reference: CFT Report, Appendix I, Table 11.4; Section 11.2.2**

13.1 For the actual Vancouver Island peak of 2,143 MW recorded in 2003/04, please disaggregate it into distribution peak, transmission peak and transmission losses.

13.2 Please confirm that the heading on p.77 should read Regional Transmission Peak Forecast instead of Regional Distribution Peak Forecast.

**14.0 Reference: CFT Report, Appendix H, General**

14.1 Please provide a functional version of the final evaluation model with a user manual.

14.2 Please provide a table summarizing each project and portfolio evaluated by the Quantitative Evaluation Committee ("QEC").

14.3 Please provide the Tender Spreadsheets illustrating the Net Tender Cost for each project evaluated by the QEC. This should include each of Tenders A through F shown in the table on page 13 of Report No. 4 of the Independent Reviewer (Appendix K, Tab 4). Please also include sheets for any additional scenarios run on each project by the QEC, where relevant (e.g., alternative electricity price forecasts and gas transportation solutions for tolling plants).

14.4 Please provide the Portfolio Spreadsheets illustrating the Net Portfolio Cost for each portfolio evaluated by the QEC. Please include sheets for any additional scenarios run on each portfolio by the QEC, where relevant (e.g., alternative electricity price forecasts). Each spreadsheet should show the annual energy dispatch for the CFT facility or facilities that were included in the portfolio, and the annual average cost of energy from the CFT facilities.

14.5 Please provide a table summarizing the Net Tender Cost for each project and the Net Portfolio Cost of each portfolio evaluated by the QEC. Please include the outcome under each electricity price forecast and other alternative scenarios, where relevant.

**15.0 Reference: CFT Report, Appendix H, Section 4.4**

15.1 Please provide a worked example of the Capacity Loss adjustment, ideally using one of the portfolios in the evaluation process.

15.2 In describing the Capacity Loss adjustment, BC Hydro states "no adjustment will be made for a negative Capacity Loss." Please clarify BC Hydro's reasoning for this approach.

**16.0 Reference: CFT Report, Appendix H, Sections 3.3.4 and 3.4.4**

16.1 BC Hydro includes contingencies of 10% on network upgrade costs and firm gas transportation costs. What is the rationale for the particular level of contingency that is applied in each case?

**17.0 Reference: CFT Report, Appendix H, Section 4.5.2**

17.1 In averaging the two portfolio costs (based on two separate electricity price forecasts), BC Hydro management is effectively putting equal weight (probability) on the two electricity price forecasts. Please provide management's justification for equally weighting both electricity price scenarios.

**18.0 Reference: CFT Report, Main Report, p. 7, Table 2**

18.1 Under Gas and Electricity Prices, BC Hydro indicates that it removed the five price scenarios and adopted one gas price forecast (EIA Reference Case) and two corresponding electricity price forecasts. What was the rationale for using a single gas price forecast?

18.2 Please provide a copy of any reports or studies that assessed the various gas and electricity price forecast options available to BC Hydro, and discuss how BC Hydro selected the gas and electricity price forecasts to use in the evaluation.

18.3 How has BC Hydro considered gas price risk in the CFT evaluation? Was the assessment of the possible effect of higher gas prices a material determining factor in any decision related to the CFT process? If yes, please identify and explain.

**19.0 Reference: CFT Report, Appendix J, p. 1**

19.1 BC Hydro states here and in several other sections of the CFT Report: "The best outcome is the one that results in the lowest NPV cost to BC Hydro and its ratepayers, on a risk-adjusted basis." What exactly does BC Hydro mean by a "risk-adjusted" basis? Please summarize exactly what adjustments BC Hydro made for risk, and how this is reflected in the comparison of project net present values ("NPV").

19.2 Please provide a summary of all input assumptions for the three CFT outcomes evaluated in Appendix J. Specifically, please provide summaries of:

- The make-up, capacity and timing of all resource additions assumed in each outcome.
- The schedule of annual energy output (or energy savings) of all resource additions included in each CFT outcome.
- The incremental capital, operating, fuel and other relevant costs associated with each outcome.
- The high gas price forecast used in the high gas scenario, and the source of this forecast.

19.3 Further to page 1 of Appendix J of the CFT Report and the previous question, please provide schedules showing the annual supply/load balance in terms of both capacity and energy and identifying the resource additions and when they occur for each of the following portfolios:

- the winning Tier 1 portfolio including Duke Point,
- the Tier 1 portfolio that placed second,
- the Tier 2 portfolio for two projects totaling 122 MW,
- the No Award portfolio, and
- the VIGP benchmark portfolio.

19.4 For each portfolio identified in the preceding question, please provide the spreadsheets used to produce the NPV of each CFT outcome and each sensitivity analysis for the "2009 Cable In-service" scenario. The spreadsheets should show the annual buildup of costs by type including system reinforcement costs and gas and gas transportation costs, any cost offsets and the determination of the NPV for the portfolio.

19.5 On page 2 of Appendix J, BC Hydro states it used the "EIA price forecast."

19.5.1 Please clarify if this is the forecast used in the Net Tender Cost and Net Portfolio Cost evaluations (i.e., EIA gas price and the two electricity price forecasts described in Appendix H, Section 3.4.4) or some other electricity price forecast.

19.5.2 If it is the forecast referred to in Section 3.4.4 of Appendix H, did BC Hydro use the average of the two forecasts or some other approach?

19.6 Please explain which gas and electricity price forecasts are used in the High Gas - Low Electricity Price sensitivity case.

19.7 On page 3 of Appendix J, BC Hydro states: "In all scenarios, the NPV of Tier 1 relative to Tier 2 and "No award" improves as the AC cable in-service date is delayed. Consequently, because of its size, Tier 1 is the CFT outcome most capable of mitigating any delay in the AC cable."

19.7.1 Please confirm that in each outcome, the delay in the cable in-service date results in an increase in required temporary generators. Are there any other impacts on the outcomes included in the sensitivity results?

19.7.2 Does the summary of required temporary generators on page 4 indicate the requirements under the 2009 in-service date? If so, please provide a summary of the required temporary generators for each delay scenario.

19.7.3 By "most capable of mitigating any delay in the AC cable" does BC Hydro mean that the Tier 1 outcome is the outcome that reduces the costs of a delay the most? Please clarify what is mean by "mitigating any delay" in this statement.

**20.0 Reference: CFT Report, Appendix J**

20.1 Further to the discussion of the Quantitative Evaluation Methodology on pages 9 to 12 of the CFT Report and the CFT Cost Effectiveness Analysis in Appendix J, please identify and explain any and all differences in methodology between the two assessments. In each case, did the portfolios look at electricity loads system wide or only on Vancouver Island?

20.2 Appendix J at page 1 refers to a gas-fired peaking plant. What would be the fuel gas requirements of this plant when it is operating at capacity? How much gas transportation capacity in terms of firm contract demand would BC Hydro need for such a plant?

20.3 Further to page 2 of Appendix J, please provide a schedule showing the annual energy prices under each of the two pricing assumptions that were used to equalize energy production, and the cost in terms of energy price of the energy losses differential. On the schedule, please also show the annual average forecast LLH electricity price and average annual price that BC Hydro expects to pay under its past and future energy calls. Please outline the basis of the price forecast for energy bought under energy calls.

20.4 Please explain the basis for the assumption that Demand Management and temporary generators will operate 240 hours per year. Based on the actual temperature profiles and major single contingency events over the past five years, how much would the bridging capacity supply have operated each year?

20.5 For the first scenario in Attachment A of Appendix J (2009 Cable In-Service, $16 million NPV for No Award and $54 million NPV for Tier 2), please provide a schedule showing how the capacity bridging supply costs for 2008 were calculated for the No Award and Tier 2 cases. Please also show the calculation assuming that the capacity bridging supply was required for 120 hours in 2008.

20.6 Page 3 of Appendix J sets out three non-quantitative considerations. Please discuss how much weight BC Hydro was prepared to give to such considerations. If BC Hydro had a maximum financial impact range or threshold that it would accept as an offset to such considerations, please provide it.

**21.0 Reference: CFT Report, Table 2, Appendix C**

21.1 Please provide further elaboration and justification of the VIGP market and salvage value assumptions contained in Appendix C.

21.2 In the Main Report (Page 7, Table 2), BC Hydro indicates the asset salvage value was changed from $20 million to $14 million. Please explain.

21.3 Please explain how the sunk costs (or salvage value) of VIGP assets was dealt with in the VIGP Benchmark Analysis in Appendix L.

21.4 Please explain the rationale for assigning an assumed market value and assumed salvage value of zero for the Gas Turbine.

**22.0 Reference: CFT Report, Main Report, Section 2.10, p. 12, Lines 18-29**

22.1 Page 12 of the CFT Report refers to BC Hydro's ability to use its existing portfolio to actively manage gas supply risk and electricity price risk, and states that BC Hydro did not include in the evaluation methodology a "risk premium" above forecast market prices for gas tolling projects. Please clarify how BC Hydro is able to eliminate gas supply risk. Please provide a copy of any studies that discuss the risk of higher gas prices with respect to the CFT.

22.2 As Duke Point is needed for capacity, please explain in detail why BC Hydro believes it and its ratepayers are not at risk of higher costs in the event gas prices turn out to be higher than the forecast it has used. Does BC Hydro believe that over the long term its cost of gas purchases will be less than actual market prices?

22.3 Please provide any information on the premium the market puts on gas supply risk (e.g., current premium on fixed price contracts over floating contracts). Please provide a copy of any studies that assess methodologies that could be used to quantify a "risk premium" to use in the evaluation methodology.

**23.0 Reference: CFT Report, Appendix L, p. 3**

23.1 Please confirm the green house gas ("GHG") cost assumption ($ / tonne) underlying the energy charge calculation.

23.2 Further to the statement about GHG liability for the VIGP Benchmark on page 1 of Appendix J, please outline the GHG liability assumptions that would result in relative savings of $55 or $115 million NPV. Which set of assumptions does BC Hydro considers to be more reasonable at this time?

**24.0 References: CFT Report, Appendix B, Appendix G, and Appendix K**

24.1 Please provide a summary of how the final mandatory bid criteria were arrived at and why each was necessary, including but not limited to Capacity, Term, Availability, Fuel supply reliability, Financial strength, Schedule, and Technology suitability. For each criteria, please outline the costs and benefits that would have resulted from specifying a less stringent requirement.

24.2 Report No. 4 of the Independent Reviewer at page 9 states that the Technical and Financial sub-committees established detailed evaluation guidelines for all Mandatory Criteria. Please provide a copy of these guidelines.

**25.0 References: CFT Report, Main Report, p. 18, Table 6**

25.1 BC Hydro conducted sensitivity analysis on three CFT outcomes, which are summarized in Table 6. This table evaluates the sensitivity of the preferred Tier 1 portfolio, the Tier 2 alternative and the No Award options. Please provide a similar analysis of the sensitivity of the other Tier 1 portfolios that were evaluated by the QEC.

**26.0 References: CFT Report, Main Report, p. 24**

26.1 Please explain the provisions for transferring GHG liability and compare these to the treatment of BC Hydro's GHG liability under the VIGP benchmark.

**27.0 References: CFT Report, Appendix O, p. 7, section 8.4**

27.1 Please provide a copy of the Benefits Agreement that is referred to in section 8.4.

**28.0 Reference: CFT Report, pp. 11, 12, 18; Appendix K**

28.1 Further to page 13 of Report No. 4 of the Independent Reviewer (Appendix K of the Report), please identify the Bidder for each tender, and identify those bids that were for gas-fired tolling plants. Is the successful Duke Point Power LP (Duke Point") bid for a tolling plant?

28.2 For the gas-fired tolling plants on Vancouver Island, specifically for Duke Point and the Island Cogeneration Plant ("ICP"), please describe the quantity and term of the firm physical gas supply arrangements that BC Hydro has in place for the supply of gas at Huntingdon/Sumas. What are the provisions in the supply contracts that BC Hydro relies on to provide reliable gas supply? If BC Hydro is relying on firm gas purchases upstream of Huntingdon/Sumas, please outline these arrangements and the corresponding firm transportation service arrangements to move the gas to Huntingdon/Sumas.

28.3 Pursuant to the provisions of Section 71 of the Utilities Commission Act, when does BC Hydro intend to file its Energy Supply Contracts related to natural gas supply for Duke Point?

28.4 In the event that BC Hydro has not contracted for firm gas supply for ICP and Duke Point from 2007 onward, please explain why BC Hydro believes that it can rely on the capacity from these generators for the period commencing 2007.

28.5 Please file the gas transportation contract or contracts that BC Hydro has entered into for the transportation of gas from Huntingdon/Sumas to ICP and Duke Point.

28.6 Please provide a schedule showing the annual gas transportation costs from Huntingdon/Sumas to each of ICP and Duke Point in the preferred Tier 1 portfolio, and outline how the costs were calculated. Please identify the gas transportation tolls and clarify the source of all assumptions about the tolls.

28.7 The CFT Report at line 21 on page 10 refers to “interruptible” gas transportation costs. Please clarify the extent to which BC Hydro has used interruptible gas transportation tolls in the analysis, and explain why it has used interruptible tolls.

**29.0 Reference: CFT Report, Sections 3.3 and 3.4, p. 6-12; Appendix H**

29.1 Further to Section 3.4.1, please provide a schedule showing both of the electricity price forecasts that were used for the portfolio cost quantitative evaluation. The schedule should show prices in a format mirroring that used in the evaluation process, should identify prices for each year and should show HLH and LLH values etc. as used in the evaluation. If the locational basis for electricity prices is not on the BC Hydro/British Columbia Transmission Corporation (“BCTC”) system, please explain the calculations that were included to adjust the prices to the BC Hydro/BCTC system.

29.2 Further to Sections 3.4.2 and 3.4.3, please provide schedules showing how one example price in 2013 was calculated for each electricity forecast. .

29.3 Further to Section 3.3.1, please provide a schedule of the forecast gas prices at Huntingdon/Sumas that were used in the evaluation of the portfolios. The schedule should show prices on an annual or shorter time period basis, mirroring what was used in the evaluation. If more than one forecast of gas prices was used, please provide all of them and indicate their source. Also, please indicate if price forecasts are in nominal or real dollars (and if in real dollars, please specify the base year).

29.4 Further to Section 3.3.3, please provide a summary of annual basis differentials used in the gas price forecast.

29.5 Further to Section 3.4.5, please provide exchange rate assumptions and sources used for all energy prices forecasts.

29.6 Consistent with the request for a corresponding gas price forecast in a subsequent question in this Information Request, please provide a schedule showing both of the electricity price forecasts that would be calculated according to the Quantitative Evaluation Methodology assuming a gas price forecast that is based on a current NYMEX forward price strip for 2007 and an assumption that the 2007 price at Huntingdon maintains its value in real terms (zero percent increase) after 2007.

29.7 Please use the forecast gas and electricity prices from the previous question to provide Portfolio Spreadsheets illustrating the Net Portfolio Cost for each of the two electricity price forecasts for the winning Tier 1 (Duke Point) portfolio. Each spreadsheet should show the annual energy dispatch for the CFT facility that was included in the portfolio, and the annual average cost of energy from the CFT facility.

**30.0 Reference: CFT Report, p. 18, lines 1 and 2**

30.1 BC Hydro’s response to the Commission’s Information Request No. 1 in the Commission hearing into the TGVI 2004 Resource Plan and Liquefied Natural Gas (“LNG”) Storage Project Application is found in Exhibit No. C7-4. Please file BC Hydro’s response to Commission Information Requests 1.3.4 through 1.7.6 as set out in Exhibit No. C7-4.

30.2 The BC Hydro response to BCUC IR 1.7.6 in Exhibit C7-4 of the TGVI proceeding states:

> "Thus GSX may be an economically viable option if a third CCGT plant were to be added on Vancouver Island within the next 5-10 years."

30.3 Does this statement mean that GSX is not an economically viable option unless a third CCGT (combined cycle gas turbine) plant is added on Vancouver Island? If not, please explain the statement.

30.4 Page 23 in Part 6 of the 2004 Integrated Electricity Plan ("IEP") that BC Hydro filed on March 31, 2004 states:

> "Based on the results of the Vancouver Island portfolios, building additional gas-fired generation on Vancouver Island beyond the call for tenders to defer the 230 kV cables from F2009 to F2016 is not a least cost alternative in the current conditions. This is a different outcome than that produced by the analysis for the VIGP application."

Does this statement set out BC Hydro's current views with regard to additional gas-fired generation on Vancouver Island? If it does not, please set out BC Hydro's current views and provide copies of any studies that support the more current views.

30.5 Please discuss whether the Duke Point site could accommodate a second gas-fired generator that is similar in capacity to the proposed Duke Point facility.

30.6 Does BC Hydro know whether the owners of Duke Point have designed the facility and sized the services and ancillary facilities in a way that would facilitate the construction of a second generator? What would be the advantages and disadvantages of doing so?

30.7 The BC Hydro response to BCUC IR 1.4.4 in Exhibit No. C7-4 of the TGVI proceeding states;

> "As to in-service schedule, BC Hydro believes that a 2007 in-service date for all options would be desirable, but not critical. BC Hydro believes that a bridging arrangement could be put in place with TGVI to accommodate the later in-service dates of other potentially more cost-effective, long-term gas delivery options for BC Hydro."

Please explain the statement, and clarify whether the references to a bridging arrangement and a 2007 in-service date not being critical refer to gas supply on Vancouver Island, electricity supply or both. If reliable gas supply to Vancouver Island for 2007 is not critical, please explain whether BC Hydro considers that it is critical to contract for capacity from Duke Point for 2007.

**31.0 Reference: CFT Report, p. 12**

31.1 Further to page 12 of the CFT Report, please provide a schedule that shows the Reference Case gas forecast that the Energy Information Administration ("EIA") issued in January 2004, and the forecast converted to Canadian dollars per gigajoule at Huntingdon, expressed in both then-current and real dollars. Further to the notes with Table 6 on page 18 and Table 8 on page 23 of the CFT Report, what is the reference date for the real dollar prices and net present values in the CFT Report?

31.2 Please describe the reference location for the EIA forecast and identify all assumptions and factors that were used to convert the forecast to Huntingdon prices in then-current and real Canadian dollars per gigajoule.

31.3 Please provide a similar schedule for the EIA High Case gas forecast issued in January 2004, and the corresponding then-current and real Huntingdon price forecasts in Canadian dollars per gigajoule.

31.4 When does BC Hydro expect that the next EIA gas price forecast will be released?

31.5 Please provide a schedule showing the most current gas price forecast by Gilbert Laustsen Jung Associates Ltd. ("GLJA") and the forecast expressed in then-current and real Canadian dollars per gigajoule at Huntingdon, identifying all assumptions and factors used to generate the schedule.

31.6 Please provide a schedule showing current forward NYMEX gas prices at Henry Hub for as far into the future as information is available, and the corresponding gas prices at Huntingdon in then-current and real Canadian dollars per gigajoule. Please identify the date of the forward price strip that was used, and identify all assumptions and factors that were used to generate the schedule.

31.7 Please use the Huntingdon prices for 2007 from the preceding response that is based on NYMEX forward prices, to generate a schedule of projected Huntingdon prices in then-current and real Canadian dollars per gigajoule, assuming that Huntingdon prices maintain their value in real terms after 2007.

31.8 Further to the reference to a high gas price scenario on page 2 of Appendix J, please describe the basis and source for the forecast, and provide a schedule of these prices at Huntingdon in then-current and real Canadian dollars per gigajoule.

31.9 Further to the preceding responses, please provide a schedule and figure that sets out for ready comparison the following projections of annual gas prices at Huntingdon in real Canadian dollars per gigajoule:

- BC Hydro updated reference price forecast from VIGP proceeding,
- BC Hydro high gas price forecast from VIGP proceeding,
- EIA Reference Case forecast issued in January 2004,
- EIA High Case forecast issued in January 2004,
- GLJA most current forecast,
- Current NYMEX forward prices,
- Projection based on current 2007 NYMEX forward prices and zero real increases, and
- High gas price forecast referenced in Appendix J.

**32.0 Reference: CFT Report, p. 15, Appendix J**
**VIGP Decision, p. 57**

32.1 Further to Table 5 on page 15 of the CFT Report, please confirm that the primary cause of the step change in F2008 in the capacity deficit for Vancouver Island is the zero rating for planning purposes of the high voltage direct current ("HVDC") systems to the Island. If this is not the case, please explain the primary reasons for the step change.

32.2 Please confirm that the HVDC systems are assumed to be zero rated as of the end of December 2007, or provide the correct date.

32.3 Please confirm that this zero rating is a judgment decision made by BC Hydro [or British Columbia Transmission Corporation "BCTC")] and is not imposed by any outside agency or authority, or explain the situation.

32.4 Please describe the most recent occasion when the zero rating of the HVDC system was reassessed. If not already filed in the Vancouver Island Generation Project ("VIGP") hearing, please provide the system condition reports that provided the basis for the reassessment, and the report setting out the conclusions of the party or group that was responsible for the reassessment.

32.5 If the zero rating of the HVDC system has not been reassessed concurrently with the CFT, and prior to making a commitment for additional capacity on Vancouver Island, please explain why not.

32.6 Are decisions such as the zero rating of the HVDC system currently the responsibility of BC Hydro or BCTC? Please explain this situation.

32.7 Further to the Expected Energy Not Served ("EENS") diagram on page 57 of the VIGP Decision, please provide an updated EENS diagram based on the current supply situation for Vancouver Island. Further to the BC Hydro response to BCUC IR 1.5.1 in Exhibit No. C7-4 in the proceeding for the TGVI 2004 Resource Plan and LNG Project, please assume that the completion date for a 230 kV AC transmission link to Vancouver Island is October 2008.

32.8 Further to Appendix J of the CFT Report, please provide an EENS diagram that shows the situation under the preferred Tier 1, Tier 2 and No Award scenarios. For each of the Tier 2 and No Award situations, please include a case that includes capacity provided by Demand Management and temporary generators as discussed on page 2 of Appendix J, and a case that does not include these additional resources.

**33.0 Reference: CFT Report, p. 15**

33.1 In Table 5 on page 15 of the CFT, how much capacity is assumed to be available from the Island Cogeneration Plant ("ICP")? Please explain the basis for the forecast.

33.2 What supply availability or reliability factor does BC Hydro assume for ICP? What has been the historical performance of the ICP in terms of scheduled and unscheduled outages? If the ICP availability has not been at least 97 percent, please explain in the context of the mandatory criteria for the CFT.

33.3 Since the Commercial Operation Date of the ICP, please provide a listing of all outages or other periods when the facility was not available. For each, please identify whether it was a scheduled outage, the cause and the duration. Were any of the outages caused by lack of fuel supply?

33.4 Please provide a concise description of each major outage, including all instances when service to customers on Vancouver Island was affected as a result. Please include the incident in mid to late October 2004. If ICP was out of service during the cold weather period in early January 2004, please include that period as well. For each outage, please outline the situation with regard to the rest of the electrical system, the cause of the ICP outage in technical terms, any changes that have been made to reduce the occurrence of such outages in the future and why BC Hydro expects Duke Point will be more or less susceptible than ICP to such outages. (For example, if ICP tripped off due to over-frequency, what was the over-frequency trip set at, what is it currently set at for ICP and what will be the setting for Duke Point?)

**34.0 Reference: BCTC Capital Plan dated May 31, 2004, p. 105**
**CFT Report, pp. 14, 16, 17**

BCTC stated at page 105 of the Capital Plan that the planned in-service date for the 230 kV AC line to Vancouver Island is October, 2008.

BC Hydro's response to the Commission's Information Request 1.5.2 in the Commission hearing into the TGVI 2004 Resource Plan and Liquefied Natural Gas ("LNG") Storage Project Application is found in Exhibit No. C7-4 for that proceeding. The response states; "…it is likely that BC Hydro will confirm the earliest in-service date for transmission reinforcement to Vancouver Island."

BC Hydro states at page 16 of the CFT Report; "Even with this acquisition, the preferred timing of new 230 kV AC cable circuit to Vancouver Island remains at that project's earliest in-service date of F2009."

BC Hydro states at page 17 of the CFT Report; "The common assumptions used for the analysis of CFT cost effectiveness are as follows: ….. 230 kV transmission cable – in service after March 2009."

34.1 Further to BC Hydro's responses to BCUC IRs 1.5.1 and 1.5.2 in Exhibit C7-4 of the TGVI proceeding, please clarify whether the "2009 Cable In-Service" cases in Attachment A of Appendix J assume the 230 kV AC connection to Vancouver Island will be in service by October 2008. If not, please explain what these cases assume.

34.2 If Attachment A of Appendix J does not assume the 230 kV AC cable will be in service by October 2008, please provide a form of Attachment A that has been expanded to show (for each scenario) the situation where the 230 kV AC cables are assumed to be in service for October 2008.

34.3 Please explain the rationale for using an F2010 in-service date as the common assumption for comparison in the Appendix J "CFT Cost Effectiveness Analysis."

**35.0 Reference: CFT Report, p. 14**

BC Hydro states; "Senior management also requested additional analysis in order to fully assess whether the selected CFT portfolio provided the most cost effective supply solution for BC Hydro's ratepayers compared to its contingency plan options and taking into account the

Commission's criteria for establishing cost-effectiveness, including cost, reliability, dispatchability, timing and location."

35.1 Please provide the detailed results of the supplementary analysis with respect to the quantification of reliability, dispatchability and timing characteristics of the Tier 1 and Tier 2 solutions analyzed.

**36.0 Reference: CFT Report, p. 2**

BC Hydro states; "The plant was thus expected to generate 265 MW of dependable capacity and to dispatch up to 2,100 GWh of energy per year."
Duke Point plant rating vs. VIGP (252 MW vs. 265 MW)

36.1 Are the gas turbine, heat recovery steam generator and steam turbine in the Tier 1 Project substantially the same as proposed for the VIGP? Please outline any material differences. In particular, what model of gas turbine is proposed for the Duke Point plant, and how does its efficiency and reliability compare to that proposed for VIGP?

36.2 Please provide an explanation for the difference in nominal capacities between the Tier 1 Project (252 MW) and the VIGP (265 MW).

**37.0 Reference: CFT Report, p.23, Section 7, VIGP Benchmark;**
**Appendix L – VIGP Benchmark Analysis**
**Commission VIGP Decision and Order No. G-55-03**

37.1 Please provide tables similar to Table 8 (page 23) and Appendix L for each of the projects in Tenders A through F as identified on page 13 of Appendix K, Tab 4.

37.2 Please provide a detailed line item comparison of the P50 capital cost estimate for the VIGP and the Tier 1 Project estimate.

37.3 Please provide Cost of Service Schedules similar to Appendix A of the Commission's VIGP Decision for both the preferred Tier 1 (Duke Point) and Tier 2 resource additions, and for the VIGP Benchmark Analysis assumptions set out in Appendix L.

**38.0 Reference: CFT Report, p. 19**

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

38.1 Please provide the technical specifications for the Tier 1 Project.

38.2 Please provide the first four years of expected dispatch and maintenance schedules for the Tier 1 Project.

38.3 Please provide industry benchmarks and other reference data for the availability and reliability indices and maintenance requirements and shutdown periods for the critical equipment in the Tier 1 Project as a function of annual operating factor and annual stops/starts.

**39.0 Reference: CFT Report, Appendix H – Quantitative Evaluation Methodology, p. 4**
**CFT Report, Appendix K4 – Independent Reviewer Report No. 4, p. 13**

39.1 Please provide the Data Sourced from the Tender as identified on pages 4, 5 and 6 of Appendix H, for each of the projects received as identified on page 7 of Appendix K4.

39.2 Please provide the availability and reliability analysis associated with each project identified on page 7 of Appendix K4.

**40.0 Reference: CFT Report, Appendix G – Addendum 10 to the CFT, p. 1**

40.1 Please provide the rationale for the change in the required EPA initial term from a minimum of 10 years to a minimum of 25 years.

40.2 What effect did this change in minimum term with the Tier 1 solution have on the size and timing of future transmission-side supply options to Vancouver Island?

40.3 Please show the projected dispatch of the Tier 1 and Tier 2 solutions in years 5 through 25, considering the planned transmission-side supply projects to Vancouver Island, given Mainland energy costs of 5%, 10% and 15% lower than Tier 1 costs (with adjustments for losses and delivery charges).

**41.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7**

BC Hydro states that network upgrade costs were provided by BCTC, and that;

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

41.1 Please provide the BCTC interconnection studies for the nine pre-qualified bidders' projects.

41.2 For each of the projects identified in the previous question, please supply a summary of the scope and cost of the system requirements and reinforcements:

- to the bidders' account; and
- to BC Hydro's/BCTC's account (borne by the system),

and the rationale for scope and cost split for each of the projects.

41.3 Please provide the detailed descriptions of the proposed generation facilities as described above, and identify those descriptions that eventually became the Tier 1 and Tier 2 projects.

41.4 Please supply copies of the bidder registration forms (CFT Report, Appendix B: Call for Tenders, Appendix 3) that were submitted.

**42.0 Reference: CFT Report, Tab J, p. 1**

BC Hydro states that the Tier 1 case will produce 1800 GWh of energy per year based on the QEM dispatch model. BC Hydro also states that there will be no energy shortfall until the year 2010.

42.1 Please provide a table showing the energy load/resource balances from 2010 to 2020. If the shortfall in 2010 is not 1800 GWh, why is 1800 GWh assumed to be the energy required from 2010 onward?

**43.0 Reference: CFT Report, Tab J, p. 1**

BC Hydro states that in order to compare the three CFT outcomes it is necessary to equalize both energy and capacity added to the system under each scenario.

43.1 Does the Cost Effectiveness Analysis assign any costs to solutions with differing levels of reliability performance?

43.2 If so, please explain how these costs were derived and assigned?

43.3 If not, does BC Hydro believe all scenarios (Tiers) will be equivalent in terms of reliability?

43.4 If not, has BC Hydro explored ways to monetize different levels of reliability? Please explain.

**44.0 Reference: CFT Report, Tab J, p. 2**

BC Hydro has used a 4.8% energy loss factor for energy transferred from the mainland to VI.

44.1 Please explain how this factor was derived.

**45.0 Reference: CFT Report, p. 17 and Tab J, p. 2**

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

45.1 Please explain the rationale for selecting temporary generation.

45.2 What other options were considered and why were they rejected?

45.3 What alternatives did BCTC offer for contingent capacity?

45.4 Does BC Hydro assume any energy backfill from the temporary generators?

45.5 Has BC Hydro modeled the temporary generators to determine if they would be economically dispatchable? If so, how much energy would be dispatched?

45.6 Would temporary generators meet the required level of reliability? What is the assumed level of reliability?

45.7 If the temporary generators are gas-fueled, what are BC Hydro's assumptions regarding gas supply for them?

**46.0 Reference: CFT Report, p. 17**

BC Hydro states that the assumption for electricity prices from the mainland generation is the same as for the Tier 1 CFT.

46.1 Please explain the rationale for this assumption.

46.2 Why does BC Hydro assume a 250 MW CCGT equivalent for mainland generation? When would this be required?

**47.0 Reference: CFT Report, p. 17**

47.1 Please explain the assumptions used with regard to the Norske Demand Management proposal, including the minimum commitments required.

**48.0 Reference: CFT Report, Table 5, p. 15**
**BCUC VIGP Decision, Table 3.2, p. 25**

48.1 Please provide a reconciliation table to correlate the values in Table 5 and Table 3.2 (from the references above), showing among other things, the specific effects of the E-Plus, Resource Smart and Green Energy capacity additions as directed by the VIGP Decision.

48.2 Has there been any further development or exploration of dependable capacity additions through E-Plus, Peak-shaving, Resource Smart or Green Energy programs or initiatives since the VIGP application? If so, please provide details of these activities and identify the timing and amount of dependable capacity associated with each.

**49.0 Reference: CFT Report, Appendix B – Call for Tenders issued October 31, 2003, Appendix 1**

49.1 Please explain the rationale for assigning a guaranteed availability of 97% to Dependable Capacity during the period of October to March.

49.2 Please provide industry benchmarks for the availability of the following types of supply sources:

- Large thermal (separate indicators for CT, co-generation and CCGT, and by component if applicable)
- Small thermal (separate indicators for CT, co-generation and CCGT, and by component if applicable)
- Large hydro
- Small hydro
- Micro hydro
- Wind
- Biomass
- HVDC (and various forms of HVDC, if available)
- Submarine cable (500 kV, 230 kV and HVDC)
- TM2500 Generators

49.3 Is there any requirement for guaranteed availability during the period of April to September? If so, please describe that requirement.