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Our File: 23841/0070

November 18, 2011

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Alanna Gillis, Acting Commission Secretary

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro") Certificate of Public Convenience and Necessity for the Dawson Creek/Chetwynd Area Transmission Project, Project No. 3698640

We are counsel for the Commercial Energy Consumers Association of British Columbia ("CEC"). Attached please find the CEC's third set of Information Requests pertaining to the above-noted matter.

A copy of this letter and attached Information Requests has also been forwarded to BC Hydro and the interveners by e-mail.

Should you have any questions regarding the foregoing, please do not hesitate to contact the writer.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb/Encl.
cc: BC Hydro
cc: CEC
cc: Registered Interveners

REQUESTOR NAME:	**Commercial Energy Consumers Association of British Columbia (the "CEC")**
IR ROUND NO:	**3**
TO:	**British Columbia Hydro & Power Authority ("BC Hydro")**
DATE:	**November 18, 2011**
PROJECT NO:	**3698640**
APPLICATION NAME:	**Certificate of Public Convenience and Necessity for the Dawson Creek/Chetwynd Area Transmission Project**

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1. Reference: Exhibit B-1, Appendix B, Page 37

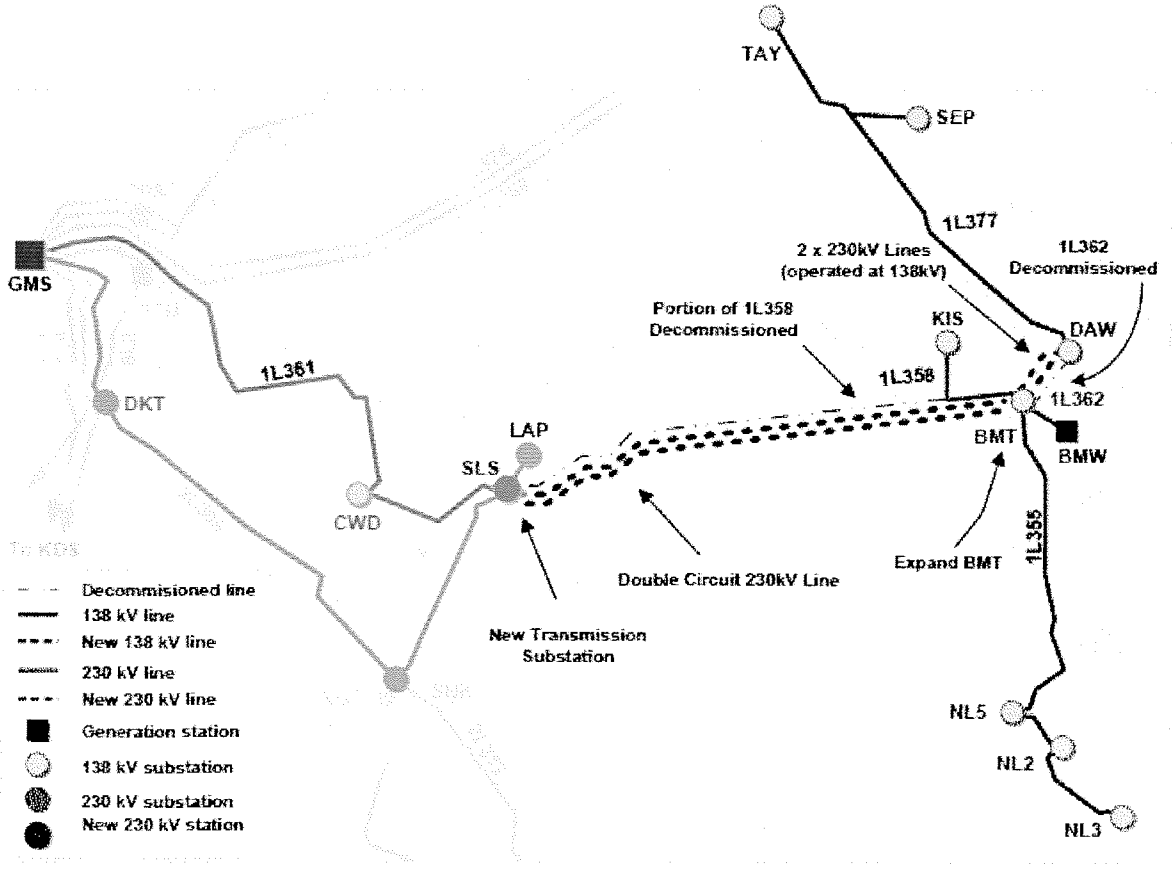


Figure 5-1: System One Line Diagram - Alternative 1: SLS-BMT 230kV Transmission line

1.1. Under the base case assumptions please describe quantitatively the VAR requirements along 1L361, 2L309, 2L312, the new 230 KV circuit SLS to BMT, 1L358, the BMT to DAW double circuit, 1L355, 1L377 and the BMT wind farm interconnection.

1.2. Please confirm that the DCAT Project does not supply N-1 service to the Groundbirch, Bear Mountain or Dawson Creek loads until the 2nd stage project is delivered in 2016, because loss of the 2L309 line would result in voltage collapse.

1.3. Please describe how upon implementation of the DCAT Project the Chetwyn, Groundbirch, Dawson Creek area transmission system would be maintained and isolated from loss of the 2L309 line.

1.4. Please confirm that the DCAT Project, for N-1 planning purposes, would also be vulnerable to loss of the 2L312 line and please confirm that the same isolation requirements provided in answer to the above question would be applicable to the loss of 2L312.

1.5. For this Alternative 1, please describe the potential requirements for interconnecting Groundbirch loads, would this require a 230 KV to 138 KV or lower distribution voltage transformation and would this be expected to be supplied by the customer. Please provide a quantitative approximate cost for the customer interconnections.

2. Reference: Exhibit B-1, Appendix B, Page 40

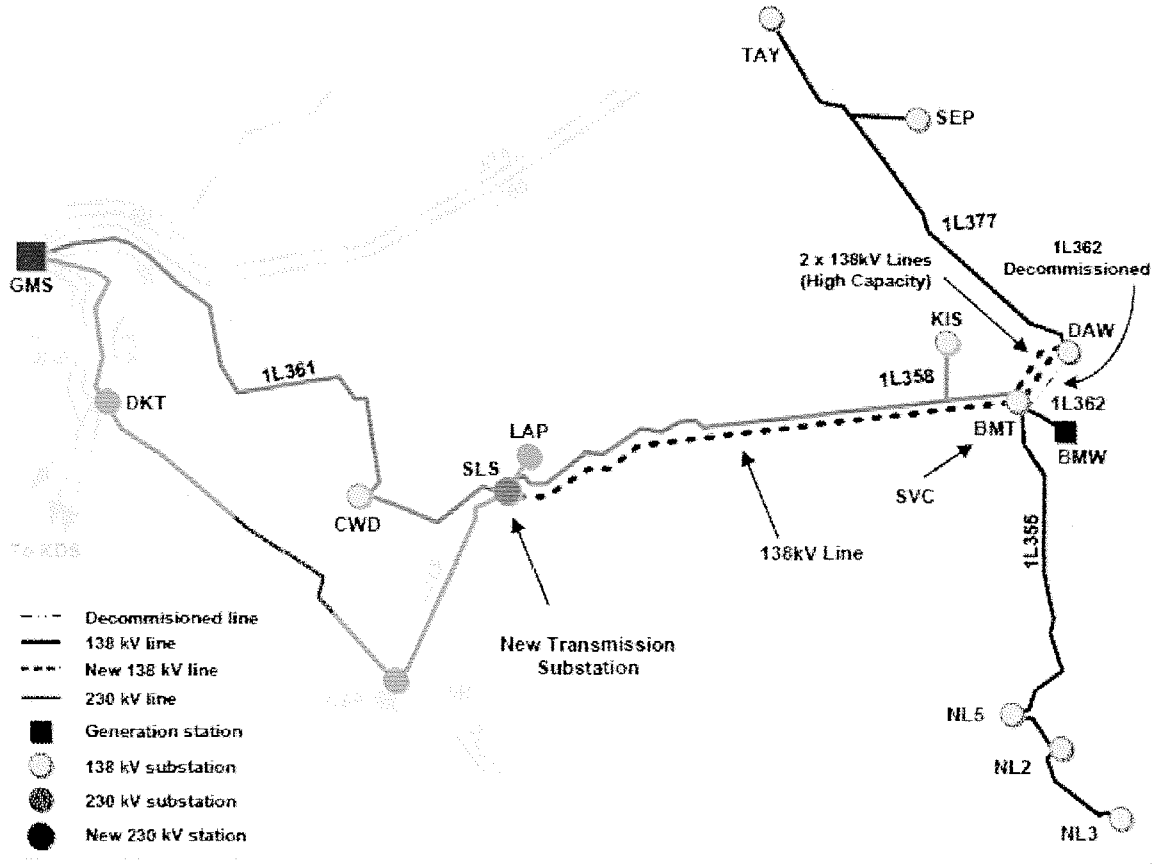


Figure 5-2: System One Line Diagram - Alternative 2: SLS-BMT 138kV Transmission line

2.1. Under the base case assumptions for this Alternative 2 please describe quantitatively the VAR requirements along 1L361, 2L309, 2L312, the new 230 KV circuit SLS to BMT, 1L358, the BMT to DAW double circuit, 1L355, 1L377 and the BMT wind farm interconnection.

2.2. Please confirm that the DCAT Project does not supply N-1 service to the Groundbirch, Bear Mountain or Dawson Creek loads until the 2nd stage project is delivered in 2016, because loss of the 2L309 line would result in voltage collapse.

2.3. Please describe how upon implementation of the DCAT Project the Chetwyn, Groundbirch, Dawson Creek area transmission system would be maintained and isolated from loss of the 2L309 line.

2.4. Please confirm that the DCAT Project, for N-1 planning purposes, would also be vulnerable to loss of the 2L312 line and please confirm that the same isolation requirements provided in answer to the above question would be applicable to the loss of 2L312.

2.5. For this Alternative 2 please describe the potential requirements for interconnecting Groundbirch loads, would this require a 230 KV to 138 KV or lower distribution voltage transformation and would this be expected to be supplied by the customer. Please provide a quantitative approximate cost for the customer interconnections.

2.6. Please confirm that the SVC requirement at the BMT is to meet the VAR injection requirements in this alternative. Please describe how the VAR requirements differ between Alternative 1 and Alternative 2.

2.7. Please confirm that local generation, using synchronous generators, connected into the BMT station could provide the VAR injection requirements, being provided by the SVC.

2.8. Please describe quantitatively the amount of local generation that would be required, in this way, to provide the VAR injection requirements.

2.9. Please confirm that local generation connected into the BMT station would reduce the losses calculated for this Alternative 2.

2.10. Please provide the loss calculations for this Alternative 2 under various assumptions of the quantity of local generation from 75 MW to 125 MW assuming base load operation for the year.

2.11. Please confirm that local generation connected into the BMT station could provide capacity to the BC Hydro system, which would have its long-run marginal cost value to the electric system.

2.12. Please confirm that local generation of up to 125 MW connected to the BMT station could provide the transmission reliability for the Dawson Creek, Bear Mountain, Sundance Substation area but would still be vulnerable to loss of 2L309, for N-1 planning purposes.

2.13. Please quantitatively describe the local generation amounts, which BC Hydro would find acceptable for providing the N-1 reliability in the Dawson Creek, Bear Mountain, Sundance area, disregarding the loss of 2L309 requirements.

2.14. Please describe quantitatively the loads on SNK, the 2L309 line, the 2L312 line and the 2L313 line, which would need to be met in the event of loss of the 2L309 line.

2.15. Please confirm that if local generation were provided to SNK in the amount of the loading on 2L309 this would be sufficient along with adequate local generation connected to BMT to provide the N-1 reliability requirements, which would be met by the DCAT Project Alternative 1 and a second stage option for additional 230 KV transmission resources.

2.16. Please describe qualitatively and quantitatively any other system planning requirements that would have to be met by a local generation alternative by 2016 to provide N-1 reliable transmission to the Groundbirch, Bear Mountain, Dawson Creek loads anticipated in the base case load forecast.

3. Reference: Exhibit B-1, Appendix B, Load Forecast, Page 79 of 100

Unconventional gas loads are primarily due to electrically-driven natural gas compression. This electrical load is due to the work energy required to move gas from the production facilities, through processing (liquids and sour gas removal) and then to boost the gas to pipeline pressures for transportation to markets. Due to the inherent efficiencies of large electric drives, the ratio of DSM to incremental electrical load allocated to this would be relatively small – in the range of 4-7% of the oil & gas related load by 10 years into the forecast period. Key DSM savings opportunities could include variable-speed electric drives, and more efficient motors at gas processing facilities.

3.1. Please describe any and all processes in which BC Hydro has discussed the efficiency of the customer's processes and designs for its plant, beyond just discussing the efficiency of the electric drives?

3.2. Please advise if BC hydro is aware of whether or not there are tradeoff's in the design of natural gas gathering systems and the related pipe sizing and compression sizing etc. such that efficiency of the process may affect demand.

3.3. Please advise whether or not BC Hydro has examined the DSM possibilities for working with the customers to determine if load can be reduced as a function of the customer system design.

3.4. Please advise whether or no BC Hydro is aware of how the gas compression customers have developed their designs in regard to the cost of energy they may have used for determining their system designs. Have they used their cost of electricity from BC Hydro or have they used the long run marginal costs of supply for BC Hydro?

3.5. Does BC Hydro know what type and makes of electric drives the customers are planning on using?

3.6. Does BC Hydro know whether or not the electric drives will be synchronous motors and whether or not the customers will be able to control the VAR requirements and or whether or not BC Hydro will be able to influence VAR requirements?

3.7. Does BC Hydro know what the VAR requirements will be for these customer loads or are the customer design decisions not yet made?

3.8. Does BC Hydro in its load forecasting make any forecasts of VAR requirements?

3.9. How does the BC Hydro system planning process make determinations of VAR requirements?

3.10. Please file all relevant material regarding BC Hydro's assessment of VAR requirements.

3.11. When BC Hydro is developed its DSM programs it at one time had VAR control as a demand side measure and was planning programs for this. BC Hydro has now developed what it calls a VVO program for Voltage Var Optimization. Please explain in detail what the plans for that VVO program have been and whether or not there have been any changes to proposed BC Hydro's capital investments to implement the program.

3.12. Please explain whether or not in the proposed compression loads of the customers there are VVO opportunities to optimize voltage and var requirements on the system.

3.13. Please explain whether or not BC Hydro's plans for the DCAT Project have optimized Voltage and Var control for these customer circumstances and if so please explain what has been done?

3.14. What if anything has BC Hydro done with the proposing customers to consider whether or not the peak capacity requirements can be optimized?

3.15. Please provide a list and description of all of the ancillary service requirements provided on the electric system to enable the delivery of electricity to end customers.

3.16. How if at all has BC Hydro considered optimizing the use of ancillary services requirements for the electric system.

4. Reference: Exhibit B-1, Appendix B, Load Forecast, Page 82 & 83 of 100

In the short term, the ratio between electrical loads to gas production is relatively small. This is because of lower gas compression requirements during the initial well production phase, and

because the initial work energy requirements during drilling and completion phase of the well life are assumed to be self-supplied. Additionally, as BC Hydro develops incremental wires infrastructure in the area, a greater percentage of current producer and incremental load may be serviced by BC Hydro. For the medium term (F2016 to F2020), demand continues to grow but at a slower pace. During this time the proportion of facilities being serviced by BC Hydro is growing. By the end of F2020, BC Hydro forecasts that gas production is expected to reach 2.4 billion cubic feet per day in the Dawson Creek and Groundbirch areas and 3.1 billion cubic feet per day for the B.C. Montney overall (projected in the Peace region forecast). There is significant uncertainty with respect to the eventual gas production from the Montney; however, BC Hydro's projection lies within the reasonable range of forecasts. Figure 5 shows the range of current gas production projections for the B.C. Montney from industry experts. BC Hydro's forecast which is used as a basis of the Producer Load Forecast is the solid line.

4.1. Please describe whether or not BC Hydro and the proposing customers have discussed whether it is optimal to have compression at the gas well head, nearer the gas plant end of the gathering lines or in between.

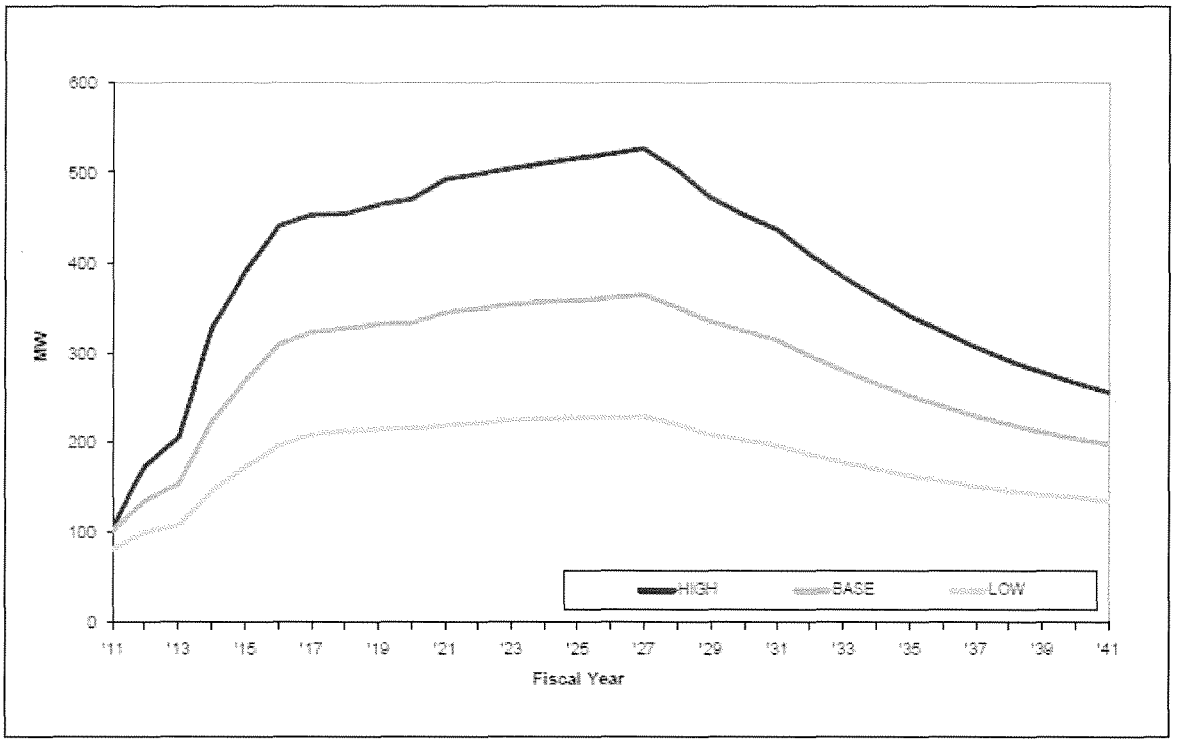
4.2. Please describe what the assumption is in the load forecasting as to the expected location of the compression along the gathering lines.

4.3. Please advise whether or not BC Hydro has examined optimizing the compression locations and requirements and if so what value for energy, capacity and other system services has been used.

4.4. Please advise whether or not the motor load efficiency changes over time with the motor load assumptions with regard to compression requirements.

5. Reference: Exhibit B-1, Appendix B, Load Forecast, Page 86 of 100

Figure 7 - Dawson Creek and Groundbirch area Load Forecast (MW)



5.1. Given the significant peakiness of the load forecast over time please explain what, if any, plans does BC have to reduce the peak requirement in order to minimize the transmission investment requirements.

5.2. When would BC Hydro make commitments to its second stage transmission design and investments in order to deliver those by 2016?

5.3. When BC Hydro is committing to its second stage investment following the initial DCAT Project will BC Hydro know whether or not it will have a high likelihood of a high, low or base case forecast load or will there still be considerable uncertainty because of the unknown variables?

6. Reference: Exhibit B-15, CEC 2.12.1

RESPONSE:

As noted in the responses to CEBC IR 2.2.4 and CEC IR 1.26.8, the marginal cost is $129/MWh, and therefore it is inappropriate to use another price to do the assessment.

6.1. Please provide for this hearing a copy of BC Hydro's Clean Power Call Final Report.

6.2. Please confirm that the basis for the $129/MWh number is the Levelized Adjusted Weighted Average Firm Energy Price (LAWA-FEP) of $124.3/MWh in $2009, which is

found on page 12 of the report in Table 3-5, inflated at a rate of inflation of 2% per annum to $2011, giving $129.3/MWh.

6.3. Please confirm that these prices for firm supply have been derived by discounting future expected cash flows under the EPAs and the adjustments made at an 8% nominal discount rate, which is found on page 8, and which includes a 2.1% inflation factor.

6.4. Please provide the calculations showing the anticipated cash flows and the discounting.

6.5. Please provide a copy of BC Hydro's latest draft Resource Options Report for both Wind and Small Hydro resources.

6.6. Please provide the cost curve data from the draft Resource Options Report for both wind resources and run of river hydro resources.

6.7. Please confirm that the data shows in both cases that significant acquisition of energy from these resources would come from sources with costs which would escalate faster over a 30 year timeframe than the 2% rate of inflation assumed.

6.8. The draft Resource Options Report was intending to have an Appendix 3 dealing with the Unit Energy Cost Adjusters. Has that work been done and if so could it be provided?

6.9. Please confirm that this identification of other cost adjusters includes items which are not adjusted for in the LAWA-FEP calculations.

6.10. Please confirm that the draft Resource Options Report data on costs presents real unit energy cost estimate data and not data with inflation assumed and that the data is not adjusted as the Clean Energy Call data is.

6.11. Please confirm that in its 2009 Clean Energy Call, BC Hydro did not acquire energy at prices reflective of the lowest cost estimates in the draft Resource Option Report.

6.12. Please confirm that BC Hydro does not have any new Resource Option data that would lead it to believe that the costs of new supply would be lower than the $129/MWh used and that is in part why BC Hydro continues to use the $129/MWh as the cost of new supply.

7. Reference: Exhibit B-15, CEC 2.12.5

RESPONSE:

The plant gate price of $116/MWh (2011 constant dollars) represents the levelized firm energy price bid by the proponents for the 25-awarded Clean Power Call EPAs based upon their plant gate price bids and contracted firm energy volumes. The plant gate price excludes the non-firm energy which will be sold into markets when available, priced at market levels.

7.1. Does BC Hydro buy the non-firm energy under EPA contracts from the suppliers at fixed prices and then sell the power into the spot markets or does BC Hydro simply facilitate the sale of the non-firm power for the suppliers and provide them the market price?

7.2. How does or will the non-firm energy from independent power suppliers compete against the non-firm energy from the BC Hydro electric system for the highest prices at the highest load hours?

7.3. Is there or will there be a priority order or does BC Hydro provide an average price back to independent power producers and provide the same average price to its ratepayers?

7.4. Please advise whether or not BC Hydro deducts transmission charges and losses from the revenues derived from sale of the non-firm power supply into the market.

7.5. Please confirm that BC Hydro does not in its economic evaluation of power call projects adjust for the impact, from suppliers with EPAs, of the non-firm power in utilizing storage and capacity as part of delivering the power to the spot markets and that these capabilities could otherwise be available to Powerex for developing trade revenues.

8. Reference: Exhibit B-15, CEC 2.12.6

RESPONSE:

The energy product that has to be acquired to provide electricity to end use customers is firm energy. Adequate storage to enable shaping of the energy is also required. In addition to energy, other products such as dependable capacity are needed to provide electricity supply to end use customers.

8.1. Please confirm that energy acquired in BC Hydro's power calls is not adjusted for storage to enable shaping.

8.2. Please confirm that dependable capacity to deliver energy to end use customers would have to be added to the energy costs in order to provide a complete "delivered to end use customer cost" and that this cost at this time is estimated as $55/KW-year.

8.3. Does dispatchability have a value to the BC Hydro system?

8.4. Please confirm that there is not an adjustment for dispatchability in BC Hydro's evaluation methodology.

9. Reference: Exhibit B-15, BC Hydro Clean Power Call, Page

Step 2: Price Adjustments
The levelized FEP was adjusted to account for differences in product attributes, and in project location relative to the Lower Mainland. Adjustments were made for hourly firm energy, wind integration, Network Upgrade (NU) costs borne by BC Hydro, Cost of Incremental Firm Transmission (CIFT) and energy losses.

9.1. Please provide a full description of the hourly firm energy adjuster and how this was determined to be $4/MWh for a flat block of energy.

9.2. Please provide a full description of the wind integration adder and how this was determined to be $10/MWh.

9.3. Please provide a full description of the Network Upgrade definition to enable an understanding of what is included and what is not included.

9.4. Please confirm that the Network Upgrade adjustment representing costs borne by BC Hydro would represent only those upgrade costs cause by the addition of the proposed project.

9.5. Please confirm that where a project utilizes network capacities and capabilities already available in the system and where a network upgrade is not triggered there would be no adder.

9.6. Please provide a full description of the CIFT definition to enable understanding of what is included and what is not included.

9.7. Please confirm that the CIFT costs are long term cost estimates for the bulk transmission system made by region and are added together by region from the project proponent region to get to a common point in the Lower Mainland.

9.8. Please confirm that the common point for the Lower Mainland is Kelly Lake, north of the Lower Mainland, or if not please provide the common point.

9.9. How does the evaluation adjust between the Network Upgrade adjustment and the CIFT to make sure that the evaluation process is not double counting, are the Network Upgrade costs all related to the local connection requirements and not to the bulk system transfer requirements?

9.10. Please confirm that energy loss studies are done for projects one at a time measuring losses with and without the project and that it is these losses which get converted into the adder for the project.

9.11. Are the loss studies done across the whole electric system or are the loss calculations made to obtain the equivalent loss to the common point in the lower mainland.

9.12. Please confirm that losses on the system are not linear with load and not necessarily additive, in that the losses for combined multiple projects in the same area would be greater than for any individual one.

9.13. Please confirm that in addition to the adjustments mentioned there is also a capacity credit provided for producers whose project provides a peak capacity contribution.

10. Reference: Exhibit B-15, CEC 2.17.1

RESPONSE:

The new wind farms, shown in Exhibit B-1, Appendix B, Table 1-2, page 17 of 100, would bring the BC Hydro South Peace Region 230 kV transmission systems close to their transfer limits. Also, the integration of these new wind farms would result in GMS 230/500 kV firm (N-1) transformation limit to be exceeded under light load conditions. When one of the GMS 230/500 kV transformer is out-of-service, generation restriction would be applied to these wind farms to avoid overloading the remaining transformer.

10.1. Please confirm that local generation in the Dawson Creek or Groundbirch areas would require these upgrades if they were to run base load and be operating at the same time as the wind farms.

10.2. Please advise that if local generation were to be added that was integrated with the wind resources so that the local generation was backed off when the wind energy was available that the local generation would then fit within the same system restriction limits that the wind farm additions do, provided that the local generation did not provide more capacity than the wind farms at peak production.

10.3. Is the above assessment of the limitations based on loads before the DCAT Project forecast loads are added?

10.4. When the DCAT Project forecast loads, particularly given that they are fairly stable base loads are the limits above relaxed somewhat and would they make more room for added local generation than, if that were to be added.

10.5. Please advise if the DCAT Project forecast loads could be served by local generation that could be added as the loads materialized.

10.6. Please advise as to whether or not the economic evaluation of the wind farm EPAs done in the Clean Power Call included Network Upgrade costs for the GMS 500/230 KV improvements to get to N-1.

10.7. Was there a transmission cluster network upgrade costs added to the evaluation for the wind resources added on the TLR, SNK, GMS transmission network.

11. Reference: Exhibit B-15, CEC 2.20.1

2.20.2 Please confirm that in addition to the generation capacity to deliver the energy to customers BC Hydro would also have to maintain reserve capacities as part of its grid interconnection requirements.

RESPONSE:

Confirmed.

11.1. Please advise if the $55/KW-year valuation for capacity includes the costs for reserve capacities or is simply the cost of capacity based on the Revelstoke Unit 6 Project.

11.2. If the reserves component is included in the price please identify the amount or the approximate percentage of the value applicable to the reserve capacities.

11.3. If the reserve components are not included then please identify an amount or a percentage addition which would be required to value the reserves component.

11.4. In the draft Resource Options Report at page 122, Table 38 the cost of new capacity beyond DSM projects appears as if it would move up sharply from $55/KW-year toward $100/KW-year. Please confirm that this is approximately correct.

11.5. Please provide the capacity value assumptions BC Hydro has used in other business case evaluations such as the SMI evaluation and please provide them by year by year quantitatively.

12. Reference: Exhibit B-15, CEC 2.11.1

RESPONSE:

The following table demonstrates how the present values would change if a 7.5 per cent discount rate was applied versus 5.5 per cent.

		5.5%		7.5%	
		Alternative 1 230 kV SLS-DAW ($ million)	Alternative 2 138 kV SLS-DAW ($ million)	Alternative 1 230 kV SLS-DAW ($ million)	Alternative 2 138 kV SLS-DAW ($ million)
1	PV - Capital Cost	227	176	218	169
2	PV – Project Total including Capital, O&M, Tax and System Losses	248	260	235	236

12.1. What is the assumption about the contribution of the Bear Mountain wind farm in reducing losses on the local DCAT area transmission, does it have an effect and if so how much?

12.2. When using the $129/MWh valuation, this includes losses to get energy to a common point in the Lower Mainland. In this case as the energy is being used and lost in the Peace Area which is a net contributor to the Lower Mainland energy requirements, why would BC Hydro not back out the losses required to get to the Lower Mainland to make a valuation more appropriate to the Peace area?

12.3. When using the $129/MWh valuation, this includes CIFT adjustments. These are necessary to make common comparisons for acquisitions of energy, however, why would BC Hydro include transmission costs in the energy valuation when it is comparing transmission alternatives.

13. Reference: Exhibit B-14, BCUC 2.1.1

RESPONSE:

Under this scenario the **SLS** would not be constructed, and the 230 kV switching station approximately 20 km east of **SLS** would become a substation. Requirements for the substation would include the planned **SLS** assets and sufficient room to accommodate future provisions, as well as 230 kV line positions to connect the Groundbirch customer. 1L358 between this substation and BMT would be decommissioned.

Under this scenario, an extra 20 km of 1L358 between this new substation and CWD would remain in service. In addition, to meet the 30-year base load forecast, two 230 kV lines would need to be connected to this station from **GMS**. This would result in three transmission lines between the new 230 kV substation and BC Hydro's proposed location for **SLS**.

Under the high forecast scenario, a third 230 kV line would be required, resulting in four transmission lines between the new 230 kV substation and the proposed location for **SLS** as compared to two transmission lines if BC Hydro's proposed **SLS** substation were constructed.

13.1. Please confirm that if the proposed substation in the BCUC question were placed in the location proposed and if there was local generation providing the base load to the Groundbirch loads that the additional 230 KV lines proposed in the response would not be needed.

14. Reference: Exhibit B-14, BCUC 2.1.2

RESPONSE:

The plan is to connect both 2L333 and 2L329 in a ring bus configuration into a new 230 kV transmission switching station that will serve as a point of interconnection for the new customer 230 kV network. This configuration is to ensure that faults on the customer system do not impact the BC Hydro transmission system.

14.1. Please advise if the customer would pay for the 230KV switching station or would BC hydro be providing the switching station.

14.2. Please provide an approximate cost estimate for the proposed switching station.

15. Reference: Exhibit B-14, BCUC 2.1.4

RESPONSE:

BC Hydro understands that the customer will be installing temporary on-site generation until the Project is in service. Subsequently, this customer will be supplied by BC Hydro.

15.1. Does BC Hydro know what type of generation the customer will be installing on a temporary basis and if so please provide details of the nature of the generation?

15.2. Please provide the quantity of temporary generation the customer is expected to supply until BC Hydro supply is available.

16. Reference: Exhibit B-14, BCUC 2.1.6

RESPONSE:

No. BC Hydro is not discussing power purchase arrangements with potential gas producer customers similar to the MCM scenario.

BC Hydro is having on-going discussions with some gas producers on potential short-term, customer-based alternatives to mitigate potential transmission line capacity constraints and the risk of interruption.

16.1. Please provide the details of the potential transmission line capacity constraints and risk of interruption issues.

16.2. Please provide the details of the potential solutions being discussed with the gas producer customers.

16.3. The BCUC question asked if not why not. Please answer the question as opposed to the answer given, which was just to say, 'no BC Hydro is not discussing power purchase agreements'.

16.4. Please confirm that if the local generation provided by the customer was zero carbon emission generation, that it could qualify as a demand side measure as a distributed generation undertaking causing a reduction in the BC Hydro load and avoiding the costs of new supply.

16.5. Please provide all relevant details on BC Hydro's distributed generation initiatives throughout the rest of its system and particularly the potential business cases and evaluation methodologies being used to examine them.

16.6. Please confirm that if local generation were being provided to service all the loads in the Dawson Creek, Bear Mountain, Groundbirch area that the losses on the electric system analyzed for the alternatives BC Hydro put forward would be reduced to the base system losses without the Dawson Creek, Bear Mountain, Groundbirch area loads.

16.7. Please provide the year by year analysis of the line losses on the electric system without the Dawson Creek, Bear Mountain, Groundbirch loads.

16.8. Please calculate the value of the reduced losses on the electric system if the Dawson Creek, Bear Mountain and Groundbirch loads were served by local generation.

16.9. Please confirm that the additional loads being added over the timeframe used for the evaluation would generate additional losses on the bulk transmission system in the order of $40 million present value, if evaluated using the $129/MWh assumption for the value of energy.

17. Reference: Exhibit B-14, BCUC 2.11.1

RESPONSE:

Under Alternative 1, connecting the new Groundbirch load to the new 230 kV transmission lines between SLS and BMT is possible because the new transmission lines would have sufficient thermal capacity to supply both the Groundbirch and Dawson Creek area loads on the loss of one of the SLS to BMT 230 kV lines.

Under Alternative 2, connecting the new Groundbirch load to the 138 kV transmission lines between SLS and BMT is not possible because the SLS to BMT 138 kV transmission lines would not have sufficient thermal capacity to supply both the Groundbirch and Dawson Creek area loads on the loss of one of the SLS to BMT 138 kV lines.

17.1. Please confirm that if local generation were to be provided to service the Groundbirch loads then this would not be a problem for Alternative 2.

18. Reference: Exhibit B-14, BCUC 2.23.1

RESPONSE:

Weighted Average Cost of Capital (WACC) and Discount Rate, are terms that will be used interchangeably.

BC Hydro has a nominal WACC or discount rate for project/business case evaluation. Under current Policy, the WACC is calculated once for a fiscal year and only changed in subsequent fiscal years if the new calculated rate differs by 50 basis points or more from the previously calculated rate. This is to promote stability in the WACC and avoid the need to constantly update business cases for changes in the discount rate. The WACC is also rounded to the nearest 25 basis points.

The WACC is found by the following formula:

WACC = (Return on Equity x Target Equity Ratio) + (Forecast Average Cost of Debt x Target Debt Ratio)

For F2012 WACC = (12.75% x 30%) + (5.25% x 70%) or 3.825% + 3.675% = 7.51%

Since the F2012 WACC is a difference of 50 basis from the F2011 WACC of 8 per cent, the WACC is adjusted to 7.5 per cent for F2012.

Where:

- Return on Equity is the allowed return on equity as established by the BCUC
- Target Equity Ratio is 30 per cent, which is established by Heritage Special Direction #HC2 and represents the target level of equity in BC Hydro's capital structure. Target Debt Ratio is the target level of debt in BC Hydro's capital structure and, given the target equity ratio, is by default 70 per cent.
- Forecast Average Cost of Debt is the average of the Canadian Dollar long-term cost of debt as provided by Treasury Board for use in developing net income forecasts for the next four or five fiscal years. The use of an average rate is deemed preferable since the timing of actual borrowing for capital projects is not known with certainty and will typically be spread over a period of time. In addition,

this is consistent with the direction provided by the BCUC in the Decision for the F2006/2007 Revenue Requirements Application to use the marginal long-term cost of debt for project evaluation. By Policy, the Forecast Average Cost of Debt is calculated annually, rounded to the nearest 25 basis points, and only changed from the previous rate if the new calculated rate is 50 basis points different. This is intended to provide stability in the rate and avoid having business cases constantly changed to reflect a new borrowing rate.

18.1. Please confirm that the WACC changes from year to year and that evaluations for the purpose of the evaluation of economic impacts would in fact change in the future as the WACC changes, to the extent that it does.

19. Reference: Exhibit B-14, BCUC 2.25.1

RESPONSE:

Please refer to response to BCUC IR 2.25.2.

BC Hydro would value incremental energy required to supply the forecasted load at $129/MWh, which is the weighted-average, levelized and adjusted firm energy price from the 2010 Clean Power Call, as discussed in response to CEBC IR 2.2.4.

19.1. The question asked would appear to have asked for the cost of the generation and the transmission, but BC Hydro has answered just with the cost of energy. Please confirm that capacity costs would also be required as would all of the related ancillary service required to service a customer.

20. Reference: Exhibit B-14, BCUC 2.30.1

RESPONSE:

BC Hydro's discussions with industry identified that the alternatives to service by BC Hydro grid power included natural gas direct drive or electrical self-generation.

20.1. When did BC hydro first have discussions with the gas producer industry and or specific gas producers about electric service in the area?

20.2. Please provide a time line chronology for the discussions with the gas producer industry and specific gas producers.

20.3. Please provide a time line chronology for BC Hydro's discussions with the government in regard to providing electric service in the area.

21. **Reference: General**

21.1. Please describe how BC hydro would implement the transmission upgrades and replacement and decommissioning of existing lines without disruption of service to existing loads or explain how the transition is made to minimize the disruption of service.