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October 11, 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 second set of Information Requests pertaining to the above-noted matter.

We acknowledge that we are late in filing these Information Requests. We advised BC Hydro of the anticipated delay on October 6, 2011. The CEC appreciates BC Hydro's accommodation in this matter. We also wish to thank the Commission for allowing the delay and apologize for the delay.

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 (CEC)**
IR ROUND NO:	**2**
TO:	**British Columbia Hydro and Power Authority (BC Hydro)**
DATE:	**October 11, 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-5, BCUC 1.32.2

RESPONSE:

The load forecast used for the Application was generated in the fall of 2010. The subsequent requests for electrical service from the gas industry in the region have been greater than was expected at that time.

1.1. Please provide the quantitative amount by which the subsequent requests for electrical service from the gas industry have exceeded the load forecast in the application.

1.2. Please indicate the type of load requests received and the approximate locations of the loads.

1.3. Please advise if these additional loads are within the middle to high band of the BC Hydro draws forecast and what implications BC Hydro draws from this new information.

1.4. Please provide BC Hydro's expectations with respect to whether or not these additional loads could make it more likely that BC Hydro should be planning for the high forecast.

2. Reference: Exhibit B-5, BCUC 1.33.2

The following are the key parameters that differentiate each of the Producer scenarios.

	High	Low	Base
Recoverable per Average Well (Bcf)	5.6	5.1	5.1
Gas Recovered (Tcf)	54	9	34
Wells Drilled (000)	8.3	1.6	5.9
Gas Price Range ($/MMBtu)	6.5-7.5	3-4.2	4.2-6.5

2.1. Please provide the known data to date with respect to the above estimating parameters for wells in the Montenay and comparable fields elsewhere if those were used and or are available.

2.2. Please explain why the base and low recoverable estimate per well are estimated at the same level.

2.3. Please explain why the total gas recovered in each of the estimates divided by the average recovered per well does not agree with the estimate of the wells drilled. (high 9.64, low 1.76, base 6.66)

2.4. Please explain why the percentage difference for each estimate of the number of wells varies from the total recoverable divided by the recovery per well (high 16.2%, low 10.3%, base 13.0%).

2.5. Please explain whether or not the forecast price range for the scenarios is a significant factor in determining the number of wells drilled.

2.6. Please explain whether or not the forecast recovery per well is a significant factor in determining the number of wells drilled.

2.7. Please advise if BC Hydro believes other factors are important in determining the number of wells drilled.

2.8. Please describe the likely percentage effect of each factor (price and recovery amount per well) on estimating the number of wells drilled.

2.9. Please elaborate on whether or not the well drilling rates are linear with factors affecting the rate of drilling or whether there would be a significant discontinuity or curve shape related to any of the factors BC Hydro has considered.

3. Reference: Exhibit B-6, 1.15.3 and Exhibit B-5, BCUC 1.35.1

BC Hydro is subject to a number of legislative requirements and regulations that will contribute to meeting Provincial GHG reduction targets. These requirements include:

- **GHG measurement and reporting under the Reporting Regulation of the *Greenhouse Gas Reduction (Cap and Trade) Act*;**
- **natural gas usage is subject to the provincial carbon tax under the *Carbon Tax Act*;**
- **net-zero GHG requirements for thermal generation under the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act*;**
- **participation in a regional cap & trade program, as per the *Greenhouse Gas Reduction (Cap and Trade) Act*; and**
- **carbon neutral requirements for corporate emissions (vehicle fleet, facility heating, cooling and lighting, and paper use) under the Carbon Neutral Government Regulation of the *Greenhouse Gas Reduction Targets Act*.**

Most recently, the *Clean Energy Act* requires BC Hydro to set out plans on how it will respond to the relevant B.C. energy objectives in its Integrated Resource Plan (IRP) process. These B.C. energy objectives include: (1) reducing B.C. GHG emissions and (2) encouraging the switching of one kind of energy source or use to another that decreases GHG emissions in B.C. BC Hydro's IRP process is underway and will address these energy objectives in the plan it submits to the Provincial Government.

3.1. Please advise if net zero GHG thermal generation fits within the definition of the Clean Energy Act 93% clean energy requirement for BC Hydro and explain the detailed definitions which are used to determine how BC Hydro meets these criteria.

3.2. Please explain whether or not the GHG objective to which BC Hydro responds in energy source switching are encouragement or mandatory.

3.3. Please explain whether or not the GHG objective to which BC Hydro responds in the energy source switching is limited by any kind of cost-effectiveness constraint.

3.4. Please explain whether or not the BCUC has the jurisdiction in its rate setting to consider the cost of the BC Government energy objectives as a consideration in whether or not to allow recovery of the cost from ratepayers for GHG reductions measures the Commission might consider as not cost-effective.

3.5. Does the BCUC have an Integrated Resource Plan available in this regulatory process to consider in its deliberation and would the last LTAP decision of the Commission be the last such planning material the Commission would have to rely on for this CPCN process.

4. Reference: Exhibit B-5, BCUC 1.35.4, BCUC 1.36.2

RESPONSE:

BC Hydro is aware of two gas producers that have committed to use gas driven motors for new compression at some of their sites in the Dawson Creek and Groundbirch areas. However, these same producers are also choosing to use electric drive motors for new compression for other sites within the Dawson Creek and Groundbirch areas.

Reference: BCUC 1.35.4

4) The relative cost of natural gas and electricity at which gas producers will opt for natural gas as fuel for production;	**BC Hydro's understanding is that electricity service at tariff rates is competitive relative to self-supply of energy (natural gas for fuel) for gas compression, which is the main energy requirement for the sector.** **BC Hydro has considered the regional resource potential, current applications for service, and the apparent attractiveness of gas vs. electricity from an overall economic perspective.** **Both these factors among other considerations help to inform BC Hydro assumption of percentage of gas production that would be electrified.**

Reference: BCUC 1.36.2.

4.1. Please provide an assessment of the economics advantage or disadvantage of gas driven compression versus electric driven compression particularly with regard to the price of electricity, the price of gas, the cost of supply and the efficiency of the equipment.

4.2. Please provide the cross over between the two options in graphic form as well as in data analysis for to clearly show at what point in the relative prices the economics for this choice may cross over.

4.3. Please advise as to what extent BC Hydro has forecast the economics of this gas producer decision in determining what its load forecast should be.

5. Reference: Exhibit B-5, BCUC 1.36.2, BCUC 1.38.2.1

1) Customers' load requests: those who have committed and those who have indicated interest but have not yet formally committed;	**Firm customer commitments for service were assigned more weight than other requests.**

Reference: BCUC 1.36.2

RESPONSE:

There are currently five industrial customers seeking 10 MW or more power. BC Hydro is seeking security from five customers for their pro rata share for the Project. Their aggregate load is reflected in Base Case Gas Producers Forecast as 92 MW and 147 MW in F2014 and F2027 respectively which is 60 per cent and 53 per cent of the forecast in those years.

Reference: BCUC 1.38.2.1

5.1. Is the Data in BCUC 1.38.2.1 in part the set of facts related to the assumption in BCUC 1.36.2?

5.2. Please provide the percentage base load forecast that is represented by firm customer commitments and the % that is represented by other requests and expectations for each year of the forecast and present this graphically.

6. Reference: Exhibit B-5, BCUC 1.37.2

RESPONSE:

Yes. The electrical intensity factor is low during the initial stage of well production, but increases as the gas formation pressure decreases. This has been appropriately factored into the Dawson Creek and Groundbirch Area load forecast.

6.1. Please supply the electrical intensity factor data for the load forecast used in this application.

6.2. Please supply the data on a year by year basis.

6.3. Please supply the assumptions for wells and gathering lines and electrical intensity as used.

7. Reference: Exhibit B-5, BCUC 1.38.1

the Natural Gas Climate Action Working Group (NGCAWG) and is comprised of representatives from the Canadian Association of Petroleum Producers (CAPP) and its member companies, the Climate Action Secretariat, and the Ministry of Energy and Mines. NGCAWG efforts have been focused on understanding: the impact of production on GHG emissions; the potential impact and viability of GHG mitigation measures (including electrification, carbon capture, and energy efficiency); key policy areas for emissions reductions within the industry; and impact of carbon policy and competitiveness on both the industry and the Province. As well, an Electricity Climate Action Working Group was formed and has been working on parallel issues.

7.1. Please confirm that this working group is restricted to the government and the industry customers who may adopt the electrification of their compression requirements.

7.2. Please advise whether or not BC Hydro has a similar collaborative working group with respect to the BC Hydro customers who will eventually pay for a substantial portion of the costs of this electrification in their electricity rates.

8. Reference: Exhibit B-5, BCUC 1.38.5

RESPONSE:

In the Gas Producer Forecast, BC Hydro used its own assumptions regarding long-term gas prices, based on a number of reviewed industry sources such as the EIA, CERA and PIRA. The range of gas prices assumed to be consistent with the Base Case is in the range of $4.20/MMBtu to $6.50/MMBtu (real). BC Hydro did not assign probabilities to these scenarios.

8.1. Please advise if this forecast of price (real) is fixed over the timeframe of the load forecast or if it varies by year and if so please supply the price forecast used.

9. Reference: Exhibit B-5, BCUC 1.42.1

RESPONSE:

Producers indicating intent – this includes and those customers providing letters of support and/or that have provided financial commitment.	**181 MW**
Producers who have shown an interest – this includes customers showing preliminary interest and currently in the study process (excluding those providing letters of support)	**374 MW**
Current capacity of the system if no upgrades were to be made	**Transmission firm capacity to the Dawson Creek area is 70 MW**
Capacity required to return transmission back to meeting BC Hydro's standard (N-1) transmission planning criteria for existing customers.	**112 MW**

9.1. Please describe the potential for the customers having provided 'intent' to require additional electrical service over the 20 to 30 year time frame or does this request represent the limit of their development.

9.2. Please describe the potential for other customers to come forward over the 20 to 30 year time frame and to request significant additions of electrical service.

10. Reference: Exhibit B-5, BCUC 1.45.1, BCUC 1.48.2

RESPONSE:

BC Hydro's application of the existing Electric Tariff on an aggregate load basis proved sufficient to protect existing customers from the risk that natural gas customers may not choose to use electricity to meet their compression needs. As such, BC Hydro does not consider that other strategies are needed to mitigate this risk.

Reference: BCUC 1.45.1

RESPONSE:

Applying Electric Tariff Supplement No. 6, BC Hydro provides an offset towards the cost of system reinforcement, in an amount equal to the lesser of (i) estimate of system reinforcement (60 per cent of $219.1 million = $131.5 million) or (ii) the BC Hydro maximum offset (of $429 million) as calculated below.

$$I = \frac{(R - E)}{0.135} + B + D$$

Where:

I = BC Hydro's maximum offset

R = Incremental revenue from the estimated annual incremental load during the first year of normal operations ($58 million from five customers providing security with a combined load of 176 MW)

E = Estimated incremental operating and maintenance expense of supplying the incremental load during the first year of normal operations ($1 million)

B = other benefits to the BC Hydro system as determined by BC Hydro (assumed to be zero)

D = one half of the annual depreciation at 3 per cent per year ($2 million)

Reference: BCUC 1.48.2

10.1. Please provide a description of the .135 factor used in the calculations supporting this statement and the assumptions on which it is based.

10.2. Please confirm that the revenue R is the total incremental BC Hydro revenue at its electric service tariff rates, which would include supply of the energy, transmission and other services from BC Hydro.

10.3. Please confirm that the Project only covers the transmission upgrades and does not include the cost to provide this service at N-1 relative to the single line 230 KV connection back to GMS, which BC Hydro will request in a subsequent application.

10.4. Please advise if BC Hydro is making any commitments to have full N-1 reliability of the 230 KV system to any customers.

11. Reference: Exhibit B-5, BCUC 1.54.1

RESPONSE:

The discount rate of 5.5 per cent is established by BC Hydro. It is the cost of capital less an average inflation rate of 2 per cent to arrive at the 5.5 per cent real discount rate.

11.1. Please provide a comparative analysis showing the present values discounted at 7.5% versus the 5.5% used.

12. Reference: Exhibit B-5, BCUC 1.54.7

RESPONSE:

Not confirmed. The PV of Alternative 1 remains lower as compared to the PV for Alternative 2 if the weighted average plant gate price is above $105/MWh.

12.1. The Clean Energy group is stating that they can supply power to BC Hydro at $85/MWh; could BC Hydro advise as to whether or not this claim has changed or will change BC Hydro's decision about selecting Alternative 2 over Alternative 1 and if not why not.

12.2. Please comment on the comparability of the $85/MWh claim and the cost of incremental new supply BC Hydro uses for its planning purposes.

12.3. Please comment in general terms with respect to BC Hydro's expectation for the incremental cost of new supply energy over the timeframe used in this application and specifically whether or not BC Hydro expects future supply costs to decline or increase in the long term from the levels BC hydro currently uses for planning purposes.

12.4. Please advise if BC Hydro has used plant gate prices in its evaluation or if it has used some other value of energy.

12.5. Please advise as to what energy product is included and what is not included in the bundle described as plant gate price.

12.6. Please advise as to what energy products have to be supplied to provide energy to an end use customer on the BC Hydro system, particularly as it may relate to capacity and ancillary services.

13. Reference: Exhibit B-6, CEC 1.1.3

RESPONSE:

As discussed in response to CEC IR 1.1.1, all loads were served at the peak for F2011.

How long loads cannot be served in the event of a transmission line outage would depend on the time to restore the transmission line. BC Hydro posted historical reliability data for 1L377 and 1L361 are as follows:

Circuit	Failure Frequency (Failure/year)	Average Outage Duration (Hours)	Unavailability (%)
1L361	0.300	8.395	0.029
1L377	1.400	5.859	0.094

Unavailability is the product of outage frequency and average outage duration on a yearly basis.

13.1. Please provide a distribution graph of the annual failure frequency for 138 KV transmission lines throughout the BC Hydro system and over a number of years to provide context to these data.

13.2. Please provide a distribution graph of the average outage duration for transmission line failures throughout the BC Hydro system and over a number of years to provide context for the above data.

14. Reference: Exhibit B-6, CEC 1.1.10 and CEC 1.1.9

RESPONSE:

The following is an estimated breakdown by customer type for the Dawson Creek area for the years F2011, F2012, F2013, and F2014.

	Residential (%)	Commercial (%)	Industrial (%)
F2011	45	16	40
F2012	25	9	66
F2013	22	8	70
F2014	18	6	75

Reference:: CEC 1.1.10

The load shedding scheme provided by the LAPS ensures that the system can be restored much faster in the event of a single contingency (N-1) event such as an outage of either of the critical 138 kV lines, 1L361or 1L377, supplying the Dawson Creek area prior to the DCAT Project. The customers understand that their participation in the load shedding scheme is important as otherwise they could all suffer an area-wide blackout. In this case it would take much longer to restore the system and the consequences would be much greater.

Reference: CEC 1.1.9

14.1. Please advise if the Industrial loads include gas producer compression loads and if so what the approximate percentage of the gas producer loads is of the Industrial loads shown above.

14.2. From the answer to CEC 1.1.9, which is the best information BC Hydro has about customers on its feeders lines, please provide assurance that BC Hydro has no information on what types of customers it has beyond residential, commercial and industrial and no idea what their operating requirements are and what the effects of load shedding may be on the customers and that the BC Hydro load shedding has no priorities as to which loads would be shed when except the priority of ensuring system voltage stability by tripping load as the system condition requires.

14.3. Please advise what it means for a customer to be participating in a load shedding scheme, is this just notice that they may be shed and how or does it involve discussion with the customers and building of an understanding about how load may be shed and how customer concerns are or may be taken into account.

15. Reference: Exhibit B-6, CEC 1.1.11

RESPONSE:

Regional information of this type is not readily available because the load profiles of some customer types are only measured as a system aggregate.

15.1. Please provide the load profiles over a year for each of the substations servicing the loads in the aggregate at which the system is measured.

16. Reference: Exhibit B-6, CEC 1.3.4

RESPONSE:

BC Hydro has estimated the overall wind integration limit of the current hydro system to be approximately 3000 MW of installed wind capacity. This wind integration limit is based on dispatchable generating capacity of hydro facilities with Automatic Generation Control that is available to deal with potential up or down swings in wind power generation. GMS is one of several generating facilities with Automatic Generation Control, and hence could be used to provide dispatchable generating capacity to follow swings in wind power generation. The current total installed wind capacity, which includes BMW, is 246 MW.

16.1. Please discuss the impacts on GMS equipment life and maintenance requirements, which may be different under significant wind integration, versus the normal customer load tracking.

16.2. Please discuss whether or not the wind integration effects on the system are linear up to the 3000 MW capability described above or whether there are likely to be non linear effects.

17. Reference: Exhibit B-6, CEC 1.3.5

RESPONSE:

Currently, there are two 500/230 kV transformers at GMS that supply the 230 kV transmission for the Peace River region. Each transformer is rated 300 MVA. The firm transformation capability from 230 kV to 500 kV at GMS is 300 MVA in compliance to N-1 planning criterion. With the integration of a large amount of wind generation on the 230 kV transmission network, these transformers could be overloaded when one of the transformers is out of service or even at system normal conditions. Therefore, the 500/230 kV transformation capability should be upgraded in order to accommodate the integration of large amounts of wind generation.

In addition, there are two 500/138 kV transformers at GMS that supply the 138 kV transmission for the Peace River region. Each transformer is rated 285 MVA. The firm transformation capability from 138 kV to 500 kV at GMS is 285 MVA. The interconnection of large amounts of wind generation to the Peace Region 138 kV system may cause transformer overload if one of the transformers is out of service or even at system normal conditions. Therefore, the 500/138 kV transformation capability should be upgraded when a large amount of wind power is interconnected to the Peace Region 138 kV transmission system.

17.1. Please confirm that wind integration to the electric system can and has used certain of the capacities and capabilities of the system to the extent that limits on the safe and

reliable operation of the system are not reached but that as the limits are reached additional investment can be required.

17.2. Please clarify where the BC Hydro system is now with respect to approaching these limits on wind integration in terms of added MW of wind generation before the limits are reached.

17.3. Please clarify whether or not the current power supply EPAs approaching their in-service dates will bring BC Hydro close to these limits and whether or not they are included in the answer to the question above regarding the current state of the system.

17.4. Please describe the nature of the upgrading to transformation which may be required in the circumstances described in answer to CEC 1.3.5, as well as approximate cost and approximate time frame to carry out the upgrades.

17.5. Please describe in quantitative terms 'large amount of wind generation' if it were to be added in the Peace area and require further system upgrades.

18. Reference: Exhibit B-6, CEC 1.8.1

RESPONSE:

As noted in Appendix B (section 2.2) of Exhibit B-1, the key opportunities for DSM savings among unconventional gas loads include variable speed drives and premium efficiency motors. For the other types of loads, DSM savings opportunities stem from the full range of DSM measures targeted by BC Hydro's residential and commercial DSM programs.

18.1. Please confirm that in addition to providing the transmission upgrades and the incremental supply of new power that existing customers will make contributions to the electrification of the gas producer loads under DSM programs in order to provide more efficient and cost effective motors that the gas producers are not expected to put in themselves.

18.2. What is BC Hydro's understanding of the type and efficiency of compressor motors the gas producers will include in their initial designs against which BCH will be considering incenting DSM measures?

18.3. BC Hydro has had distributed generation and load displacement in its DSM portfolio in the past, has BC Hydro tested the gas producers to find out what level of compensation would induce them to self-supply these potential compression or processing plant loads and if not why not?

19. Reference: Exhibit B-6, CEC 1.8.4

RESPONSE:

BC Hydro, as part of its Integrated Community Strategy has been in discussions with the City of Dawson Creek to jointly investigate the potential for renewable energy opportunities within the Dawson Creek area. These activities are currently in the preliminary stages and include a possible Request for Expressions of Interest (RFEOI) for a capacity-based distributed generation-type project(s), totalling around 10 MW in size.

The RFEOI would be led by the City of Dawson Creek, with BC Hydro's support on the development of the RFEOI technical details and specifications. Decisions regarding moving forward would be made jointly between the City of Dawson Creek and BC Hydro.

19.1. Please describe whether or not this proposed generation would likely involve intermittent electrical energy supply and therefore would not likely contribute to the capacity to serve the area and therefore the transmission capacity is fully required.

20. Reference: Exhibit B-6, CEC 1.16.4

RESPONSE:

System reserves are not required for energy and hence the cost for acquiring reserves is included only in the cost of new dependable generation capacity supply.

20.1. Please confirm that the $129/MWh ($2011) cost of new energy supply does not include the cost of system generation capacity required to deliver the energy to customers.

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.

21. Reference: Exhibit B-6, CEC 1.16.5

RESPONSE:

The cost of new dependable generation capacity would be based upon the capital costs of Revelstoke Unit 6, estimated at $55/kW-year in current dollars. BC Hydro has not carried out an assessment of the shaping required for delivering the energy as required by the customer use profiles, and as such this data is not presented.

21.1. Please confirm that while BC Hydro has not carried out such an assessment the capability is required to deliver energy to customers.

22. Reference: Exhibit B-6, CEC 1.23.3

Not confirmed. The firm transmission capacity after the implementation of the DCAT Project will be constrained by voltage and not transmission line thermal capacities. Therefore, the firm capacity cannot be described as the simple addition of individual line capacities but rather the system's ability as a whole to support system voltages within acceptable ranges.

Please refer to the response to CEC IR 1.2.2 which provides a description of the considerations and method used to determine transmission capacity.

22.1. Please provide the transfer capabilities for each of the lines coming into DAW, given the anticipated voltage stability of the upgraded transmission.

23. Reference: Exhibit B-6, CEC 1.26.3

RESPONSE:

In the event self-sufficiency definitions change, the cost of energy may change in the near term. The valuation of losses will be recalculated if and when the self-sufficiency criterion is changed.

23.1. As losses form a significant component of the project evaluation and alternative selection and because the Province is currently reconsidering its policy with respect to self-sufficiency the CEC believes that the Commission needs to understand the risk potential for this part of the evaluation to change and affect its decisions. Please provide a cost of energy for two cases that BC Hydro would use if 2500 GWh/year or 5000 GWh/year of non-firm energy could be used in the BC Hydro system backed up by market purchases.

24. Reference: Exhibit B-6, CEC 1.38.1

(2) The electricity demand expectations in the North Coast region continues to increase and loads could see a sudden and significant increase in the next few years due to the potential development of LNG facilities. The region is currently interconnected to the rest of the system by a single 500 kV circuit that would not be capable of transferring sufficient electricity to serve the new loads. Developing new transmission lines is estimated to take at least eight years. Gas-fired generation may be the only feasible option to meet the load in the interim.

24.1. Please provide BC Hydro's best information at this time of the potential LNG facility loads in the Province, in terms of MW.

24.2. Please advise whether or not the LNG facility power supply issue may raise, in the next IRP, issues about the need for the LNG facilities to self-supply power.

24.3. Please advise whether or not BC Hydro's understanding is that significant gas producer development in the Montenay and Horn River areas and the potential LNG facilities are connected parts of the same economic development of natural gas in the Province.

24.4. Please confirm that the DCAT project is proceeding under the current legislation and policy of the Province and advise as to whether or not BC Hydro is engaged in discussing power supply policy issues with Province at this time in regard to natural gas economic development in the Province and for the next IRP.