OWEN·BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0070

August 24, 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 first set of Information Requests of the CEC pertaining to the above-noted matter.

A copy of this letter and attached Information Requests has also been forwarded to BC Hydro and the intervenors 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 Intervenors

REQUESTOR NAME:	**Commercial Energy Consumers Association of British Columbia (CEC)**
INFORMATION REQUEST ROUND NO: **#1**	
TO:	**British Columbia Hydro and Power Authority (BC Hydro)**
DATE:	**August 24, 2011**
PROJECT NO	**3698640**
APPLICATION NAME:	**Certificate of Public Convenience and Necessity for the Dawson Creek/Chetwynd Area Transmission Project**

1.0 Reference: Exhibit B-1, Page 2-1

> As a result of load growth in the Peace region of B.C., particularly the Dawson Creek area, the transmission system supplying the region is now operating whereby the system cannot currently serve the entire peak load with a single transmission element taken out of service (N-1) and is forecasted to not be able to support the peak load with all transmission elements in service (N-0) in the winter of 2013/14. Consequently, it is necessary to upgrade the regional transmission system as soon as possible.

1.1 Please identify what loads are not served at the peak for F2011.
1.2 Please quantify the loads are not served at the peak for F2011.
1.3 Please quantify for how long the loads cannot be served at the peak for F2011.
1.4 Please quantify at what times the loads cannot be served at the peak for F2011.
1.5 Please quantify the amount of energy not provided at the peak for F2011.
1.6 Please identify and quantify the same information as above as estimates for F2012, F2013 and F2014.
1.7 Please describe the load shedding regime and rules in place for F2011.
1.8 Please describe the load shedding regime and rules planned for F2012, F2013 and F2014.
1.9 Please provide BC Hydro's best information with respect to the impacts on customers, whose load must be shed for F2011, F2012, F2013 and F2014.
1.10 Please provide a breakdown of the load by customer type for F2011, F2012, F2013 and F2014.
1.11 Please provide annual and peak daily load profiles for each of the customer types identified above.
1.12 Why has BC Hydro not provided peaking support in the area to date?

1.13 BC Hydro has identified in the application upgrades to the area system in the form of addition of 12.5 MVAR 138KV Shunt Capacitor Banks at Dawson, are there any other additions planned before the in service date for the DCAT project?

1.14 Please confirm that the shunt capacitors and transformer additions planned at Dawson for identified in the application for F2012 are in service or are on track to be in service before this coming winter.

1.15 Please confirm that the shunt capacitor and transformer additions at DAW are not part of the DCAT project.

1.16 Please confirm that the shunt capacitors and the transformer additions at Dawson are being installed to service new loads and not to increase reliability for the existing customers who have load shedding regimes in place now or if the answer is a partial mix of service for both new and existing please quantify how much these additions would be expected to affect service to both the existing loads and to the new loads.

1.17 What peaking support, if any, does BC Hydro plan to provide other than the aforementioned additions for F2013 and F2014?

2.0 Reference: Exhibit B-1, Page 2-5

The existing Dawson Creek 138 kV transmission system is capable of serving the current needs of the Chetwynd area and approximately 50 MW of firm load (N-1) and 120 MW of non-firm load (N-0) into the Dawson Creek and Groundbirch areas. By the end of 2011 transfer capability into the Dawson Creek and Groundbirch areas will increase to 70 MW firm (150 MW non-firm) though the addition of four 12.5 MVAr 138 kV shunt capacitor banks at DAW.

2.1 Please provide the power transfer capability of the 1L361 138 KV line to Chetwynd on its own for N-1 in the event of the loss of the BMT to CWD line 1L358 and the capability at CWD for N-0.

2.2 With 70 MW of transfer capability coming into DAW from CWD and BMT and 70 MW of transfer capability coming in from TAY, please explain how this creates the 150 MW capability at DAW being more than linear addition.

2.3 Can the capability at DAW be enhanced by stringing additional 138 KV transmission wiring on the existing transmission structures, such that each phase has a double conductor line separated by spacing bars, and if so please explain by how much the capability would be enhanced and please explain why this might change the transfer capability?

2.4 Please explain what if any other kinds of equipment might be capable of changing the power transfer capability of the 138KV system serving DAW and how that equipment would accomplish the change.

3.0 Reference: Exhibit B-1, Page 2-5 and 2-6

26 The only local source of generation in the Dawson Creek area is the 102 MW Bear
27 Mountain Wind Farm located approximately 15 km south west from the City of
1 Dawson Creek, which provides an intermittent source of electricity to the area. The
2 wind farm is connected to BMT by a customer owned 138 kV line (1L354).

3.1 Please confirm that the Bear Mountain Wind Farm cannot be counted on for any capacity capability throughout the 138 KV system serving the area.

3.2 If there were a local generation capability in the Dawson Creek area, what difference to the service capability in the Dawson Creek area could such a generation source make? Please be specific and quantitative in the answer.

3.3 Please provide a daily profile of the Bear Mountain Wind Farm annual generation of energy such that one can identify how many days of the year BMW is generating how much energy.

3.4 Please describe how the BMW energy generation is integrated into the BC Hydro system and particularly the requirements this may place on the GMS facilities and or any other facilities affected.

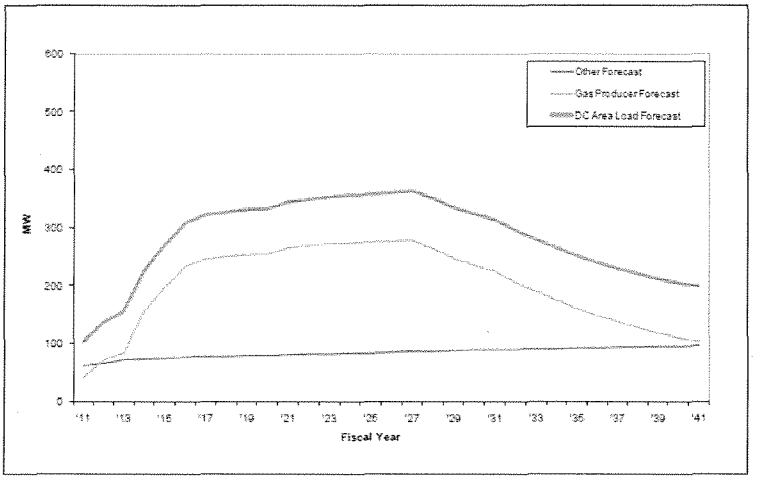
3.5 Please describe the limits, if any, of the GMS facility to integrate additional wind farm generation from the Peace River area.

3.6 Please describe and quantify any progressive impacts on the GMS facilities from progressive additions of wind generation in the region.

3.7 Please identify whether or not BC Hydro has identified back-up generation capability of customers in the area and if so please quantify the amount.

4.0 Reference: Exhibit B-1, Page 2-7

Figure 2–3 Dawson Creek and Groundbirch areas Gas Producer Forecast and Other Forecast (MW)



4.1 Please provide a specific point mapping of where the loads are anticipated to be within the Dawson Creek and Groundbirch areas.

4.2 To the extent a specific point mapping is not possible, with the current level of customer requests and intents currently being studied, please provide a breakdown between the Dawson Creek area and the Groundbirch area.

4.3 Please identify quantitatively how much of the Groundbirch area load could be served from the SNK substation and how these loads could be served from SNK.

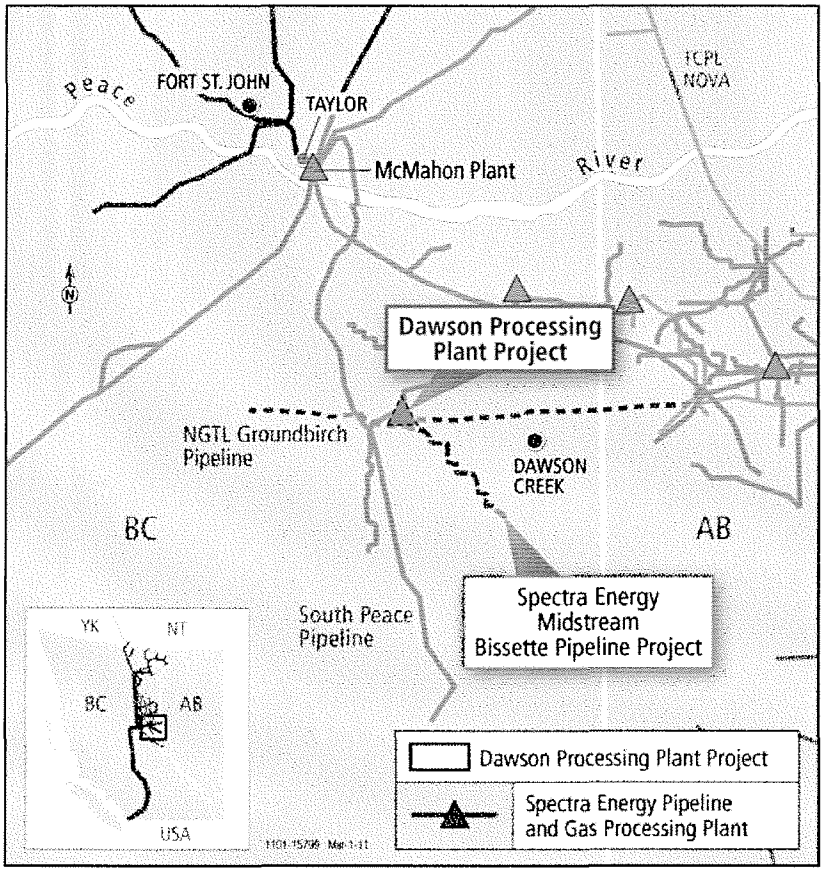
4.4 Please describe why BC Hydro the BC Hydro area transmission planning does not expect that it is possible to service load from the SNK substation yet in a second stage for serving maximum loads options include 230KV transmission from SNK.

4.5 Please identify whether or not any of the other portions of the 230KV system might be suitable sources of power for servicing the Groundbirch and or Dawson loads.

4.6 Please identify the potential magnitude of gas producer loads per compression unit.

4.7 Please identify what would be required to service gas producer loads from the 230 KV transmission system, presumably 230KV transformers stepping down to 138 KV transmission voltage for transmission customers and to distribution levels for distribution customers.

5.0 Reference: Spectra Website



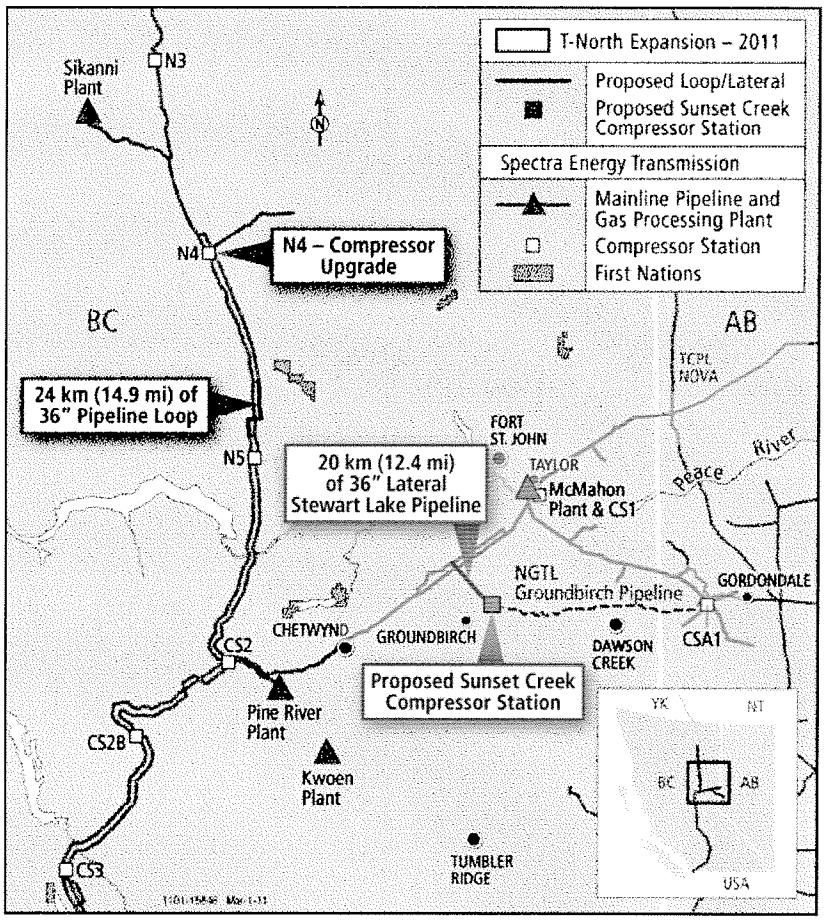
- Location: Dawson Creek area, northeast British Columbia
- Approximate Size of Proposed Facility: 60 acres
- Processing Capacity:
  - Phase 1: 100 million cubic feet per day (MMcf/d)
  - Phase 2: 100 million cubic feet per day (MMcf/d)
- Source of Gas Supply: Montney shale gas formation/South Peace region
- Ownership Interest: 100% Spectra Energy
- Operator: Spectra Energy
- Projected In-Service Dates:
  - Phase 1: Q4 2011
  - Phase 2: Q1 2013

Driven by the continued development of the Montney play, Spectra Energy is building the Dawson Processing Plant to process raw natural gas from the South Peace region to meet the scale, scope and timing of our customers' processing needs.

The project involves the construction of a double train gas processing plant featuring inlet separation, compressor facilities, a vapour recovery unit, and a radio communications tower.

Raw natural gas will be processed at the plant, meaning that CO2, natural gas liquids and H2S will be extracted. H2S and CO2 removed at the plant will be blended with raw gas gathered upstream of the plant and transported to the South Peace Pipeline for processing at Spectra Energy's existing McMahon Gas Plant. The processed sales gas will be transported via a short connector to the NGTL Groundbirch Pipeline.

Construction, which began in Q1, 2011 is being completed in two phases, with Phase 1 projected to come into service in Q4 2011 and Phase 2 in Q1 2013.



- Location: Fort St. John area, northeast British Columbia
- Two pipeline segments: 24 and 30 kilometres of 36" diameter
- Capacity: Approximately 170 million cubic feet per day (MMcf/d)
- Scope:

- Installation of a new compressor unit at Compressor Station N4 to provide additional horsepower and other station upgrades
- The construction of approximately 24 kilometres (14.9 miles) of 36-inch looping on the Fort Nelson Mainline between Compressor Station N4 and Compressor Station N5
- The construction of approximately 20 kilometres (12.4 miles) of 36-inch pipeline ("The Stewart Lake Pipeline") extending from Spectra Energy's existing Fort St. John Mainline southeast to NGTL's Groundbirch Receipt Meter Station
- The construction of a new compressor station at the southern end of the Stewart Lake Pipeline (the "Sunset Creek Compressor Station")

- Ownership: 100% Spectra Energy
- Operator: Spectra Energy
- Project Completion Date: Q2 2012

As a result of a successful binding open season held in May 2010, Spectra Energy signed long-term contracts with shippers which will support a 170 million cubic feet per day (MMcf/d) expansion of the T-North system and enhance market outlets. Subject to regulatory approval, construction is anticipated to start in early 2011, with the project in-service in the second quarter of 2012.

The increased capacity will be realized by "looping" one section of the T-North pipeline system, installing a new compressor at an existing compressor station, constructing a new pipeline connector and constructing a new compressor station.

Spectra Energy's pipeline system is well positioned for future growth based on customer need and timing. A second binding pipeline open season in 2010 resulted in a further 550 MMcf/d committed under long term demand-based arrangements supporting a further expansion of the T-North system in the 2012/2013 period. That project is currently under development.

5.1 Please identify whether or not these Spectra Projects in the Groundbirch area are included in the BC Hydro load forecasts and how much load is anticipated.

5.2 Please indicate whether these loads would be served from DAW, BMT or SLS.

5.3 Given the location of a gas processing plant in the Groundbirch area and connections to the South Peace Pipeline and to the CS2 to Taylor area CS1 and McMahon plant, it would appear that this would be a focal point for a considerable amount of the potential load, is this correct.

5.4 Given the potential load in this area, is there a possibility in the development of load such that a significant portion of the load may not need to be serviced from DAW and therefore the transfer capability upgrade all the way to DAW may not be a necessary as the planning shown in the CPCN may indicate.

5.5 What if any examination of the potential detailed interconnections and loads has BC Hydro used to develop the transmission systems planning or has it been essentially the area load forecast assumed to be focused on DAW that has driven the planning?

5.6 What other specific planned loads is BC Hydro aware of? Please provide all details known.

5.7 Has BC Hydro investigated the potential for co-generation opportunities next to the planned Dawson processing plant, as is the case in Taylor?

5.8 How could such a cogeneration opportunity help and assist the electrical supply stability, thermal limitations and future load service in the area?

6.0 Reference: Exhibit B-1, Page 2-9

5 The primary use for electricity in the production of natural gas is for compression to
6 keep natural gas pressurized, both in the field gathering system and at the
7 processing plant. Natural gas is typically consumed as fuel for compression.
8 Historically electric driven motor compressors had been less frequently used in
9 natural gas production operations largely due to: the remoteness of many field
10 locations and the need to install power lines; and the fact that natural gas fuel is
11 readily available from the producing properties. For economic and environmental
12 reasons, where reliable electricity is available, as is the case in the Dawson Creek
13 and Groundbirch areas, the use of electric driven motors for new compressors has
14 been growing. As a mitigation strategy, substituting natural gas drive compression
15 with electric drive compression supplied by low carbon power from BC Hydro's
16 electric system offers the potential to significantly reduce the increase in GHG
17 emissions expected as a result of increased activity. As illustrated in Figure 2–3, the

6.1 Please describe the potential natural gas fueled compressors and the electric driven compressors, in technical terms, particularly for their energy requirements and their compression performance.

6.2 Please describe how the compression requirements for a producer may change over time for a given well and or gathering line.

6.3 Please describe whether or not it would be possible to have natural fueled compression and electric compression as alternatives, such that the electrical service could be interruptible service.

6.4 Please describe the compression requirements for a producer from wellhead to treatment plant in terms of the required maximum time frame for which compression may not be available before there would be an appreciable decline in the delivery of natural gas to the processing plant.

6.5 Please describe the economic impacts on producers for interruption to the compression capability for various lengths of time for which interruption may be expected to occur for both natural gas fueled compression and electric driven compression.

6.6 Please describe quantitatively the economic reasons for wanting electric driven compression versus natural gas fueled compression.

6.7 Please describe quantitatively the GHG reduction reasons for wanting electric driven compression versus natural gas fueled compression.

6.8 Please calculate the cost of GHG reduction in terms of $/tonne of CO_2 equivalent for using electric driven compression, using the marginal costs of supply for electricity and for natural gas, in regard to these natural gas producer customers GHG emissions for electric driven compression versus natural gas fueled compression.

7.0 Reference: Exhibit B-1, Page 2-10

In aggregate, the Dawson Creek and Groundbirch areas average annual load growth over the next thirty years is forecast to achieve a peak load of 363 MW in F2027. The DC Area Load Forecast is characterized by very high annual load growth of approximately 25 per cent in the period between F2010 and F2016 and annual load growth of approximately 1.4 per cent in the period from F2017 up to F2027. Beyond F2027 the loads are forecast to decline at a rate of 4.5 per cent per year.

7.1 Please describe the certainty BC Hydro has with respect to the decline rate for the compression loads, in terms of a probability distribution across the range of potential decline rates.

7.2 Please describe the certainty BC Hydro has with respect to the growth rates for the compression loads, in terms of a probability distribution across the range of potential growth rates.

8.0 Reference: Exhibit B-1, Page 2-10

Figure 2–4 shows the potential impact of DSM initiatives. The DSM savings associated with unconventional gas loads are expected to be in the area of 4 to 7 per cent, and for all other types of loads the DSM savings could reach 6 to 9 per cent. DSM initiatives would not be enough to address the capacity shortfall which exists in the Dawson Creek area. DSM initiatives are not expected to defer the in-service date for a project to increase transmission capacity, nor would DSM make a difference in developing the alternatives to meet the 30-year load forecast. For these reasons, BC Hydro did not considered DSM further for the purposes of this application.

8.1 Please describe the DSM measures that would lead to the proposed DSM savings.

8.2 Are the DSM savings the usual BC Hydro savings, being described as a percentage of the GWh usage?

8.3 Are the DSM savings shown graphically in Figure 2-4 as MW capacity savings the same percentages as described above?

8.4 Has BC Hydro looked at Distributed Generation options in the Chetwynd Dawson Creek area to mitigate or minimize transmission investment and or line losses?

8.5 Has BC Hydro looked at agreements with customers, particularly compression load customers, with respect to their needs for reliability?

8.6 Has BC Hydro determined what the compression load customer needs for reliability are?

9.0 Reference: Exhibit B-1, Page 2-12

The Dawson Creek and Ground Birch areas firm transmission supply capacity is limited to 70 MW by voltage stability with the loss of 1L377 (TAY-DAW). As a result of recent and significant area load growth, the area load has now exceeded this level. Significant reactive power support, totalling 70 MVAr, has already been installed at DAW to improve the voltage performance of the system. Power flow studies shows that the addition of enough reactive power compensation in the Dawson Creek area to supply the forecast load would not be sufficient because the loss of 1L377 would then result in the thermal overload of 1L361 starting in the winter F2012 and 1L358 starting in F2013.

9.1 What would be the effect on the voltage stability with the loss of the 1L377 line, if there were a 75 MW firm energy generation source in the Dawson Creek area?

9.2 What would be the effect on the voltage stability with the loss of the 1L377 line if there were an interconnection to the Alberta substation 55 km east of Dawson Creek?

10.0 Reference: Exhibit B-1, Page 2-12

The CWD firm transmission supply capacity in the Dawson Creek and Groundbirch areas is limited to a load of 85 MW by voltage stability on the loss of 1L361 resulting in voltage collapse. The Dawson Creek and Groundbirch loads have now exceeded this level. Power flow studies show that the addition of enough reactive power compensation to overcome voltage constraints would not be effective because the loss of 1L361 would then result in the thermal overload of 1L377 starting in the winter of F2012.

10.1 Is the proposed limitation of the N-1load serving capability in Dawson Creek (70 MW) a function of the least capability of 1L377 and 1L358 in series with 1L361?

10.2 BC Hydro describes the N-0 capability at Dawson as 150 MW, is this achieved by 70 MW on 1L377 and 85 MW on 1L358?

10.3 What would be the maximum transfer capability from CWD to BMT under N-0 conditions, if there were sufficient reactive power compensation available?

10.4 How much additional reactive power compensation would be required to support the maximum transfer capability from CWD to BMT?

10.5 What would be the effect on the voltage stability with the loss of the 1L361 line, if there were a 75 MW firm energy generation source in the Dawson Creek area?

10.6 What would be the effect on the voltage stability with the loss of the 1L361 line if there were an interconnection to the Alberta substation 55 km east of Dawson Creek?

11.0 Reference: Exhibit B-1, Page 2-13

2.4.1.4 Low Voltage - Outage of 1L362 (BMT-DAW)

Starting in the winter of F2014, the loss of 1L362 would result in low operating voltages at the BMT 138 kV bus.

11.1 What would the cost be for adding one additional 138 KV line from BMT to DAW?

11.2 What would the power transfer capability be for an added 138 KV line from BMT to DAW?

12.0 Reference: Exhibit B-1, Page 2-13

10 ***2.4.1.5 Thermal Limits and Low Voltage - System Normal Conditions***

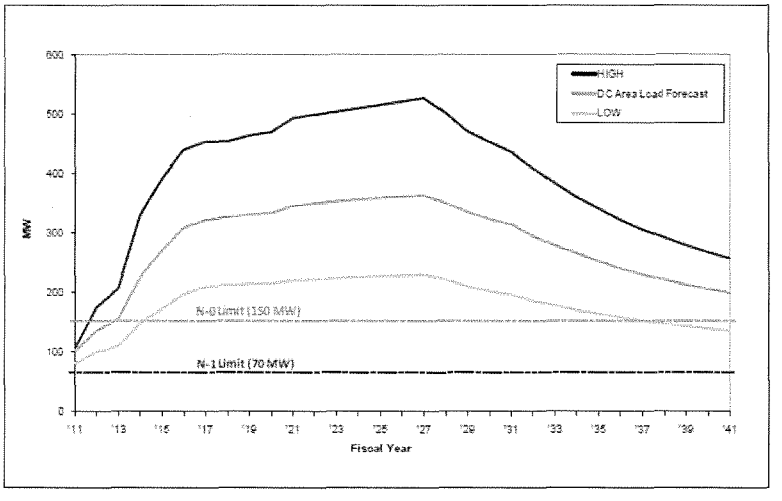
11 Starting in F2014 during winter conditions with all system elements in service the
12 system will experience: 1) low 138 kV voltages at BMT resulting in transmission
13 voltage customer Electric Service Agreements (**ESAs**) not being met: and 2) low
14 voltages for the DAW 25 kV system. Overcoming these voltage constraints using
15 reactive power compensation equipment would not resolve the thermal constraints
16 resulting from the single transmission line outages discussed above.

12.1 What are the terms and conditions in the ESAs which BC Hydro has with customers in this area that would govern the actions BC Hydro would take in the event of low voltage conditions?

12.2 What are the terms and conditions in the ESAs which BC Hydro has with customers in this area that would govern outages of one of the system elements for supply to the area that would govern the actions BC Hydro would take to avoid thermal constraints arising from a single transmission line outage?

13.0 Reference: Exhibit B-1, Page 2-14

13 **Figure 2–5 Load Forecast Scenarios**



13.1 Please provide 3 graphs comparable to Figure 2-5, one each for Groundbirch loads, loads to be serviced from BMT and for load to be serviced from DAW.

14.0 Reference: Exhibit B-1, Appendix B, Appendix C

The recent recession has resulted in a lowering of continental gas demand, which has decreased market natural gas prices and tightening credit; these factors have led to delays in Montney gas projects. BC Hydro's gas price forecasts, as presented in its recent stakeholder consultation sessions for its 2011 Integrated Resource Plan recognize this decrease in long-term gas price projections.

14.1 Given the continuing flat performance of the US economy and recent financial market concerns, what is the probability that the Montenay gas projects may experience further delays?

15.0 Reference: Exhibit B-1, Page 2-16

4 Upgrading the transmission system in the Peace region will allow natural gas
5 producers to connect to the BC Hydro electric system providing clean electricity to
6 meet their compression requirements rather than the alternative of using natural gas
7 driven compressors. Based on the expected electrical load from gas production that
8 would be served via the Project, the avoided/reduced GHG reductions from using
9 electric compressors rather than gas driven compression is in the range of 1 million
10 tonnes per year in B.C. There is potential for further avoided/reduced GHG
11 emissions as future gas production in the Montney basin is electrified.

15.1 How can the GHG reduction be in the range of 1 million tonnes per year in BC when the load forecast for GWh of energy used, which would displace energy otherwise used for compression rises over a period of years and then declines significantly over a period of years?

15.2 Please provide the GHG reduction estimate year by year throughout the forecast period matched with the assumed GWhs delivered to load for each of the base, high and low forecasts.

15.3 Does BC Hydro have a specific mandate and or target to be reducing GHG emissions?

15.4 Does BC Hydro have any cost limits to its undertakings which may limit GHG reductions?

16.0 Reference: Exhibit B-1, Page 2-17

The upgrading of transmission infrastructure in the Peace region will bring low cost electricity into the fastest growing industrial sector in B.C. The potential scope of shale gas development in the Montney is vast.

16.1 Please provide for each year of the forecast period the price the gas producers would be expected to pay for electrical supply in terms of energy charges, demand charges and basic charges along with any other charges which may be applicable.

16.2 Please estimate the customer revenue BC Hydro would expect to receive for each year alongside the base case forecast electrical supply.

16.3 Please provide BC Hydro's projected cost of new supply for firm energy for each of the years throughout the 30 year forecast period.

16.4 Please advise whether or not this projected cost of new supply for energy includes an estimate for the system reserves which must be maintained for system reliability associated with the provision of electric grid system supply.

16.5 Please provide a projected cost for each year for providing the generation capacity and shaping required for delivering the energy as required by the customer use profile.

16.6 Please advise what the economic impacts are for the Province, related to the increased costs to BC Hydro customers for this energy supply.

17.0 Reference: Exhibit B-1, Page 2-17 and 2-18

The choice between gas and electricity for compression will not be the primary determinant of the extent of development in the Montney. At the margin however, it is a significant decision that must be made by producers and the choice of reasonably priced electricity may tip the balance in favour of development in particular circumstances. The very significant contribution that shale gas development can make to B.C.'s economic future makes any contribution BC Hydro can make to encourage that economic development significant.

17.1 Does BC Hydro have a mandate to be making contributions to gas producers to encourage economic development?

17.2 Could BC Hydro provide an estimate as to what percentage of the natural gas producer cost structure gathering compression energy may represent?

18.0 Reference: Exhibit B-1, Page 2-18

10 The current capacity constraints of the Peace region transmission system coupled
11 with the significant anticipated load growth provide a compelling reason to construct
12 the Project without SD No. 9. However, SD No. 9 underscores the importance of
13 planning to ensure inadequate transmission capacity does not hamper economic
14 development in the province. Simply put, in the absence of the Project, BC Hydro
15 will not be in a position to meet customer requests for electricity connection in the
16 Peace region.

18.1 Please confirm that in the absence of BC Hydro supplying the gas producer loads the gas producers would likely proceed with natural gas fuelled compression and the economic development in the province would not vary significantly other than for the cost reductions which would take place in the BC Hydro cost structure.

19.0 Reference: Exhibit B-1, Page 2-18

22 need to be quite robust. Accordingly, BC Hydro has designed the Project, as set out
23 in this application, to provide a significant improvement in BC Hydro's ability to serve
24 Dawson Creek and Groundbirch area loads and to serve as a base to which
25 significant additional capacity can be added as required.

19.1 Please quantify the significant additional capacity being provided in the BC Hydro proposed project, such that the unutilized capability can be understood.

20.0 Reference: Exhibit B-1, Page 2-19

7 The pro rata share for each of the five large customers that have requested service
8 was calculated on the assumption that 40 per cent of the capacity of the Project is
9 required to return the transmission system back to meeting BC Hydro's standard
10 (N-1) transmission planning criteria for existing customers already taking service.
11 The other 60 per cent of the capacity of the Project will be to serve the five large
12 loads with interconnection requests to BC Hydro. Therefore, the amount of security
13 sought from the customers with interconnection requests will be equal to 60 per cent
14 of the cost of the Project.

20.1 In the event that the existing system load could be brought to N-1 reliability sooner and at a lesser cost than 40% of the DCAT project cost, does BC Hydro have the ability to require greater pro rata share security?

20.2 Please quantify and the five load requests in terms of MW of capacity.

21.0 Reference: Exhibit B-1, Page 3-2

It must be noted that two major projects with different in-service dates are required to meet the full 30-year load forecast; the first in F2014 (**Project**), and the second in F2016 which will be referred to as the F2016 stage (**F2016 stage**). This Application addresses the F2014 stage only. The evaluation of the F2016 stage alternatives will be the subject of future proceedings, as necessary. Both stages are independent decisions. The selection of a specific alternative for the Project does not impact any alternative decision of the F2016 stage, and the selection of a specific alternative in the F2016 stage does not impact the alternative decision in the Project. Because the Project and F2016 stages are independent, a common F2016 stage project was established to evaluate Project alternatives. For further information on F2016 stage planning, please see section 4.5 and the System Planning Report in Appendix B.

21.1 What should BC Hydro do if the two project stages are not independent as BC Hydro asserts they are?

21.2 What does BC Hydro believe the Commission should do if it finds that the two project stages are not independent?

21.3 What would BC Hydro do with an alternative project to meet 2014 requirements, which is less expensive than the one BC Hydro has proposed but requires a different project to meet the 2016.

21.4 Does BC Hydro believe it is necessary to have a common 2016 stage to evaluate the alternatives?

21.5 BC Hydro proposes that the selection of the Project does not impact any F2016 stage, however, if BC Hydro made the first stage alternatives as either a 138 KV line or 230 KV line from SNK to BMT then both the first stage and second stages would have been different, is that not correct?

22.0 Reference: Exhibit B-1, Page 3-3

5 Given the very rapid and dramatic changes in the load forecast, BC Hydro has not
6 advanced the F2016 stage sufficiently to bring forward a CPCN application at this
7 time. Accordingly, BC Hydro has decided that the Project should not be delayed to
8 include the F2016 stage project scope because: there is an immediate need for
9 additional transmission capacity in the Dawson Creek and Groundbirch areas; and
10 further upgrades can be assessed independently from the Project.

22.1 Has BC Hydro's choice of the Project option essentially precluded the development of a CPCN for any other F2014 transmission options because there would be insufficient time to develop the CPCN application and obtain approval?

22.2 Would BC Hydro agree that some forms of local generation solutions in the Dawson Creek area could be developed and implemented to meet F 2014 requirements?

22.3 Would BC Hydro agree that if the F 2014 requirements were met by another project other than the one BC Hydro is proposing that in F 2016 BC Hydro could bring forward an application for transmission solutions that may respond to the load as it develops over and above the F2014 requirements?

23.0 Reference: Exhibit B-1, Page 3-4

3 The addition of a new 230 kV double circuit transmission line, together with the new
4 SLS and corresponding upgrades at BMT and DAW, will increase the firm
5 transmission capacity that serves the Dawson Creek area to 185 MW. With

23.1 Please confirm that the firm capacity that serves Dawson Creek is the N-1 capability to transfer power to DAW.

23.2 Please confirm that the assumption behind the 185 MW capacity involves an assumption that one 230 KV line would be out.

23.3 Please confirm that because 70 MW is available from 1L377 that the remaining transmission lines would have the capability to deliver 115 MW, versus the 85 MW that could be delivered from 1L358, which is to be removed to put in the 230KV lines.

23.4 Please confirm that this transfer capability is limited by possibility of the 2L312 line being out.

24.0 Reference: Exhibit B-1, Page 3-5

3 The addition of a single new 138 kV transmission line constructed on double circuit
4 structures, together with the new SLS and corresponding upgrades at BMT and
5 DAW will increase the firm transmission capacity that serves the Dawson Creek area
6 to 207 MW. With the F2016 stage in service, this alternative will meet the forecasted

24.1 Please confirm that the 207 MW firm transmission capacity serving Dawson in this alternative would assume an outage of one of the 138KV lines delivering power to BMT or DAW.

24.2 Please identify and quantify the contributions made to the firm transmission capacity by the additional 138 KV line, the interconnection with line 2L312, and the 110 MVA SVC addition at BMT.

25.0 Reference: Exhibit B-1, Page 3-8

Table 3–2 Capital Expenditures

		Alternative 1 ($ million)	Alternative 2 ($ million)
1	F2014 Stage	160.0	105.5
2	F2016 Stage	96.5	96.5
3	Total	256.5	202.0

25.1 Please provide a breakdown of the F2014 stage costs as follows

F 2014 Stage

Alternative #1	Direct $	PV $
SLS 230 KV Substation		
60 km 230 KV double circuit SLS to BMT		
12 km 230 KV double circuit BMT to DAW		
BMT 138 KV and 230 KV line and transformer positions		
DAW complete 138 KV ring bus and 138 KV line position		
138 KV line removal		
Total		

F 2014 Stage

Alternative # 2	Direct $	PV $
SLS 230 -138 KV substation		
60 km 138 KV line SLS to BMT		
12 km 138 KV double circuit from BMT to DAW		
110 MVA SVC at BMT		
BMT 138 KV line and transformer positions		
DAW complete 138 KV ring bus and 138 KV line position		
Total		

F 2016 Stage

Common	Direct $	PV $
73 km 230 KV line GMS to SNK		
30 km 230 KV line SNK to SLS		
GMS 230 KV line position		
replacement of 500/230 KV transformers		
SNK line position		
SLS line position		
Total		

26.0 Reference: Exhibit B-1, Page 3-9

With respect to system losses, for each alternative computer system modeling of the Peace region was used to calculate average yearly network losses (MW) converted to energy losses (MWh) and monetized at $129/MWh.[16] In the result, Alternative 1 would incur lower transmission system losses because it's designed with 230 kV transmission lines. A 230 kV system is more efficient for the following reasons:

26.1 Please confirm that the cost of energy used is for a flat block of firm energy on the BC Hydro system.

26.2 When evaluating system network losses, please explain why BC Hydro uses firm energy values.

26.3 In the event that self-sufficiency definitions and or requirements are changed for BC Hydro how might that change the cost of energy applicable to valuing losses?

26.4 Does the loss energy, which is being saved, have to be delivered on a firm basis as it relates to the firm load serving requirements of customers?

26.5 Does the loss energy, which is being saved, have to be delivered with system capacity resources and shaping as it relates to the load serving requirement of customers?

26.6 Given that the $129/MWh is a weighted average, this would mean that BC Hydro at the margin is paying more than the $129/MWh value, would it not?

26.7 Please confirm that BC Hydro expects to continue to acquire additional energy throughout the 30 year study period.

26.8 Please confirm that the 2009 Clean Power call energy may be applicable to only the early years of the 30 year study period.

26.9 Please update and advise as to whether or not the 2009 Clean Power call attrition rate is currently expected to be the same as when the call results were announced.

26.10 After deducting the specific known attrition projects and the anticipated attrition projects, would the weighted average of the remaining project energy costs be about the same as the $124/MWh, which is the basis for the updated to 2011 $129/MWh value being used.

26.11 Please confirm that the BC Hydro Resource Options information indicates that the cost of new supply curves for all of the clean energy sources rises as BC Hydro more energy is sourced from the given supply option.

27.0 Reference: Exhibit B-1, Page 4-3

Double circuit steel monopoles have been selected as the typical structure for the Project. Though capital construction cost for double circuit monopole structures is higher than the lowest cost wood single circuit H-frame, double circuit monopole construction results in a significantly lower number of structures due to their longer span lengths and combination of two circuits on one set of structures, and reduced ROW requirements (as two or more H-frame single circuit lines would be required to carry conductors that could accommodate the Project requirements). The double circuit structures require minimal, if any, guy wire support requirements, and there is a smaller footprint for each monopole structure. Therefore, using double-circuit steel monopole construction for the proposed new transmission lines lowers the impact on the environment and land use as compared to other alternatives, by minimizing clearing, reducing the environmental fragmentation that would result from multiple lines, and minimizing operational changes to agricultural landowners. Minimizing these impacts increases general acceptance of the transmission line and reduces land acquisition risk that could impact the in service date. In addition, the steel construction is expected to have longer life and lower maintenance costs during its life cycle.

27.1 Has BC Hydro investigated using pre-stressed concrete spun cast transmission towers in place of steel towers?

27.2 Has BC Hydro investigated using hybrid, pre-stressed concrete spun cast transmission tower bases with steel pole tops?

27.3 Please provide the criteria and formulas BC Hydro uses to determine line sag and therefore pole spacing, recognizing but ignoring that the specific terrain issues will interact with these for final design determinations.

27.4 Please describe how the conductor separation between the double circuit lines is determined, why it is wider for the middle conductor and narrower for the bottom and top conductor.

27.5 Please describe quantitatively the tradeoffs which determine the conductor separation and what is compromised for the compact design and quantitatively how much the tradeoff value is for the compact design.

27.6 Please describe quantitatively the cost tradeoffs between pole height and pole spacing.

28.0 Reference: Exhibit B-1, Page 4-5

The existing 138 kV ROW (for lines 1L362 and 1L358) is generally 18 m in width, although it is less in some areas, particularly where the line is located within road allowance. The average ROW width required for the Project 230 kV line, at spans of about 300 m to 400 m, would be approximately 33 m. Where the new line will be located next to one of the existing 138 kV lines, there is a reduction in the required new ROW width due to overlap, thus the additional ROW required will be approximately 26 m.

28.1 Please advise quantitatively how the 33 m ROW width is determined for the 230 KV line.

28.2 Please advise if the bottom conductor distance to the ground level is more important than the distance of the other conductors to the ground level and quantify why.

28.3 Please advise if the 33 m ROW width is determined based on the minimum distance to the ground level from the lowest point of the conductor sag to the ground.

29.0 Reference: Exhibit B-1, Page 4-5

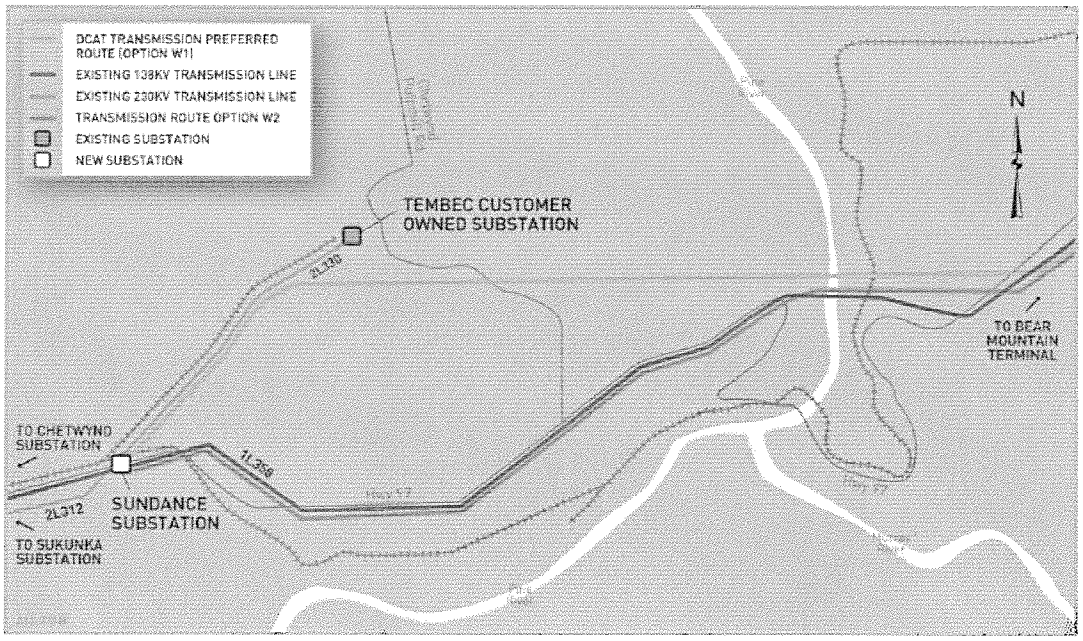
Transmission line ROWs must be cleared to prevent flashovers and possible safety issues due to growing/falling vegetation. All trees within the ROW will be cleared, which is estimated to be approximately 130 hectares (320 acres, 1,297,707 m^2).

29.1 Will some percentage of the cleared trees be of timber quality and if so how much.

29.2 Has BC Hydro determined if any of the cleared trees could be of use to the Tembec mill.

30.0 Reference: Exhibit B-1, Page 4-13

Figure 4–5 Route Options East of Pine River SLS (West Segment)



30.1 Please provide the scale for the transmission route maps.

30.2 Please advise is BC Hydro looked at locating the Sundance substation at the customer owned Tembec site, to shorten the length of 230 KV line required, given that the preferred route virtually goes to the station anyway.

31.0 Reference: Exhibit B-1, Page 4-15

Once the new Project 230 kV transmission lines are in place, the existing 1L362 and 1L358 lines will not be required to serve load in the Dawson Creek area. To minimize Project footprint and environmental fragmenting, and to reduce ongoing operations and maintenance costs, the lines where appropriate will be decommissioned and removed. Line 1L362, which runs between BMT and DAW, will be removed along its entire length. Except for 5 km of line from BMT to a customer tap and the portion of the line from CWD to the new SLS substation, 1L358 will be decommissioned. Lines 1L362 and the decommissioned portion of 1L358 will be removed and salvaged in 2014, after the Project transmission lines are fully commissioned.

31.1 How much is the salvage expected to be for the decommissioned 138 KV lines?

31.2 Has BC Hydro done a tradeoff of salvage value versus the potential over the 30 year period to provide 138 KV service from BMT, DAW or SLS to surrounding developing loads.

31.3 How was the decision to decommission made?

32.0 Reference: Exhibit B-1, Page 4-15

SLS will be a 230/138 kV transformation station having the following:

- 4 x 230 kV line bays – two for in/out of 2L312[17] and two for the new 230 kV circuits 2L329 and 2L333 to BMT;
- 1 x 230/138 kV power transformer; and
- 2 x 138 kV line bays for in/out of 1L358.[18]

32.1 When determining the reliability, is N-1 constrained by the single 230/138 KV power transformer, which if out would be equivalent to taking out the two 230 KV transmission lines?

33.0 Reference: Exhibit B-1, Page 4-25

4.7.2 Price Escalation Assumption

No escalation factor has been applied to the Project beyond inflation at B.C. Consumer Price Index.

33.1 Please provide the BC construction inflation index for the last 5 years and BC Hydro's expectations for this in the next 3 years.

34.0 Reference: Exhibit B-1, Page 6-14

17 ***6.1.6.1 Summary of Consultation to Date***

18 A high level summary of BC Hydro's consultation process to date is provided below.
19 Supporting documentation related to the consultation communications between
20 BC Hydro and each First Nation can be found in Appendix G.[29]

34.1 Why does BC Hydro not consult its customer group representatives, while it is in the process of developing the project and alternatives prior to the CPCN application to the Commission?

35.0 Reference: Exhibit B-1, Page 7-1 and 7-2

20 The need for the Project is discussed in Section 2.5. As explained there, some
21 enhancement of the transmission system is required to meet current loads. Thus,
22 there is a high level of confidence that the Project will provide some benefit by
23 enhancing the quality of service to existing customers. However, the Project is also
24 required to serve significant, industrial customer demand. To minimize the risk that
25 the industrial customer demand does not materialize, BC Hydro has sought sufficient

1 security from new industrial customers to cover 60 per cent of the costs of the
2 Project. The risk of unused capacity burdening ratepayers in these circumstances is
3 thus low.

35.1 Is there a risk of significant load materializing in the Groundbirch area, such that the load needing to be serviced from DAW or from BMT may be less than the capacity being designed and built all the way to DAW?
35.2 How does the security cover the cost of the Project?
35.3 Please provide the terms and conditions for the security.
35.4 Is the security released based on customer revenue over time?
35.5 How much customer revenue does BC Hydro estimate is required to insulate existing customers from unutilized or stranded cost of transmission infrastructure?
35.6 Has BC Hydro considered any other mitigations of this risk or has it only considered the security proposal it has adopted?

35.7 Is there a risk that the 60% estimate is too low for the actual exposure of BC Hydro customers that the cost impacts on customers may be well in excess of the portions BC Hydro believes it has secured?

36.0 Reference: Exhibit B-1, Page 7-2

The security arrangements BC Hydro has adapted for this project provide that the risk of 60 per cent of the actual cost of the Project will be taken by those new customers for whom it is being built. To control their exposure and the exposure of existing customers to the 40 per cent of Project costs which would affect them, BC Hydro has robust cost risk management programs that can be grouped into two broad categories: risks that may occur due to procurement issues, and those issues that may be encountered during the detailed design or construction of the Project and may require a change.

36.1 Would it be fair to say that BC Hydro's procurement risk management is essentially the application of its normal procurement process as applied to this project?

36.2 With the exception of the proposed tariff changes to the security provisions is BC Hydro doing anything new that it has not done in procurement before to mitigate risk?

36.3 Would it be fair to say that BC Hydro's detail design and or construction risk management is essentially the application of its normal practices applied to this project?

There is a risk that the Project is not adequate to meet accelerating load growth. BC Hydro is managing this risk by actively developing the F2016 stage and undertaking the Project in a manner that is completely supportive of future reinforcement through the F2016 stage. No other configuration of the Project has been identified that would provide better protection against this risk.

Reference: Exhibit B-1, Page 7-5 and 7-6

36.4 Is it correct to say that not meeting accelerating load growth is not much of a risk because the natural gas producer customers have the option of natural gas fueled

compression and are expected to be using this in situations where BC Hydro service will not be cost-effective to them?

36.5 Has BC Hydro's review of this risk been confined to project configurations or has BC Hydro looked at other options and if so what were those other options and what was BC Hydro's assessment of the other options?

There is a risk that the Project will not meet future requirements as soon as they emerge but no other Project configuration has been identified that would enhance capacity more quickly. In addition, BC Hydro will take steps to mitigate this risk by considering accelerated ROW acquisition activities and pre-ordering equipment where appropriate.

Reference: Exhibit B-1, Page 7-6

36.6 Is BC Hydro planning to pre-acquire ROW and equipment before it has the Commission approval of its CPCN?

36.7 In pre-ordering is BC Hydro imposing a potential cost risk on its customers if the Commission requires some elements of the Project to be changed?

36.8 Under what terms would BC Hydro be pre-ordering and pre-acquiring, would it be subject to the Commission's decisions?

37.0 Reference: Exhibit B-1, Appendix A, Page 63

- Interconnection with Alberta

The closest lines in the Alberta system are 138kV lines approximately 55km from Dawson Creek Substation, and the closest 230 kV line is approximately 200 km from Dawson Creek Substation (direct point-to-point distance)

37.1 Please provide the cost for a 138 KV line to the Alberta system tapping off a 138 KV line and connecting to DAW.

37.2 Please provide the potential power transfer capability for a connection to the Alberta system.

38.0 Reference: Exhibit B-1, Appendix A, Page 64

- IPPs and local generation opportunities

The following are potential generation developments identified to-date in the peace region:

38.1 Please describe the potential for natural gas fueled generation in the Dawson Creek area.

38.2 Please identify why BC Hydro has not considered natural gas fueled generation an option.

38.3 Please identify quantitatively where BC Hydro is currently with respect to the 93% clean objective, in terms of its use of fossil fueled generation sources.

38.4 Please identify the room from where BC Hydro is currently to the 93% clean objective in terms of MWs of generation and GWhs of generation.

39.0 Reference: Exhibit B-1, Appendix B, Page 17

Table 1-2: Near Term Wind Generation Projects

	ISD	MCR (MW)	ELCC (MW)	POI
Wildmare Wind Energy Project	2012	77	16	On 2L309, 17 km north of SNK
Tumbler Ridge Wind Energy Project	2012	47	10	On 2L323, 9 km from TLR
Quality Wind Project	2012	142	33	TLR 230kV bus
Meikle Creek Wind Energy Project	2013	117	25	On 2L313, 23 km north of TLR
Bullmoose Wind Energy Project	2015	60	13	On 2L322, 25 km from TLR

39.1 Please provide the transmission system map, like Figure 1-1 Existing Peace Region Transmission, with these wind generation projects located on the map and the transmission upgrades required to serve them also shown.

39.2 What would be required to connect from one of these wind projects to the 1L355 line to BMT.

40.0 Reference: Exhibit B-1, Appendix B, Page 21

The existing facilities in the Dawson Creek 138kV transmission system, including the short term reinforcements identified in section 1.2.1, have limited supply capacity to serve current and projected load. Figure 2-3 shows that the existing system cannot serve the entire winter peak load today with a single transmission line taken out of service (N-1), and starting in F2014 the system will not be able to support the winter peak load in the Groundbirch and Dawson Creek area with all transmission lines in service (N-0). Adding new load connected in the Groundbirch area to this system is not possible until a major transmission project is in place to increase the transmission capacity into the Dawson Creek and Groundbirch areas.

40.1 Why is the load in the Groundbirch area assumed to be served from the Dawson Creek area?

40.2 What would be the best way to serve Groundbirch loads from the 2L312 or 2L313 lines or from SNK, TLR, LAP or other substation located for the purpose?

40.3 How might serving the Groundbirch loads from the 230KV system side of the area transmission be affected by the proposed wind projects in the area and the transmission system upgrades they may require and be putting in place?

41.0 Reference: Exhibit B-1, Appendix B, Page 26

Prior to the implementation of a major project to increase the load serving capacity into the Dawson Creek and Chetwynd areas, BC Hydro is considering interim measures to manage the shortfall in capacity. Some options being considered are:

a. The implementation of a Local Area Protection Scheme(LAPS) which would shed load in a controlled manner under certain critical system outages,

b. Load interconnection contracts which designate new loads as interruptible under any system condition. This is an interim measure only, as transmission planning standards TPL-001 and TPL-002 set by the North American Electricity Reliability Corporation (NERC) require that no loss of demand result when all facilities are in service or after events resulting in the loss of a single element. This interim measure also does not meet BC Hydro N-1 planning criterion.

c. Short term reactive power contracts from local IPPs or customers to provide a dependable supply of reactive power under any system conditions.

d. Transfer of load from the Dawson Creek area to neighboring areas.

41.1 Why would interruptible power loads have to be served by a transmission system planned to N-1 capability?

41.2 What is the consequence to BC Hydro for not meeting TPL-001 and TPL-002 NERC for interruptible loads?

41.3 What loads from Dawson Creek would be transferred to neighbouring areas and where would they be transferred to?

41.4 Please describe and quantify the short term reactive power options and or potential which might be considered as well as provide an estimate of the cost for such.

42.0 Reference: Exhibit B-1, Appendix B, Page 29

Table 4-1: Assumed new load Point of Interconnection

Area	Assumed Point-of-Interconnection
Dawson Creek area	DAW 25kV bus and BMT138kV bus
Groundbirch area	New Sundance Substation 138kV bus[6]
Chetwynd area	CWD 138kV bus
Fort St-John/Fox area	FJN 138kV bus
GMS area	PPS 138kV bus

42.1 Please provide the quantitative assumptions with respect to each point of load connection for each of the five areas listed and aggregate these to the total area load forecast assumption.

43.0 Reference: Exhibit B-1, Appendix B, Appendix C, Page 80

3. The substantial potential in wind generation in the Peace region. Recent wind generation interconnection studies have identified a need to for additional transmission capacity on the 230kV transmission system between Tumbler Ridge substation and GMS.

43.1 What transmission system upgrades are required to service the Peace wind generation projects, which have approved EPAs?

43.2 Are the independent power producers with approved EPAs for additional wind generation in the Peace paying for transmission system upgrades?

43.3 What transmission system upgrades would be required to service additional Peace wind generation, which may likely be added in future BC Hydro power calls during the next 30 years?