489 Pages

BC HYDRO – CPCN FOR DAWSON CREEK/CHETWYND AREA TRANSMISSION PROJECT EXHIBIT B-6

Janet Fraser
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September 22, 2011

Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

RE: Project No. 3698640
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Application for a Certificate of Public Convenience and Necessity (CPCN)
for the Dawson Creek/Chetwynd Area Transmission Project (DCAT)

BC Hydro encloses its responses to Round 1 Intervener Information Requests as follows:

Exhibit B-6	Public Version
Exhibit B-6-1	Confidential Version

BC Hydro also encloses as Exhibit B-5-2 an amendment to BCUC IR. 1.38.2.1.

For further information, please contact Geoff Higgins at 604-623-4121 or by e-mail at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

for Janet Fraser
Chief Regulatory Officer

gh/af

Enclosure
Copy to: BCUC Project No. 3698640 (DCAT) Registered Intervener Distribution List.

The British Columbia Public Interest Advocacy Centre

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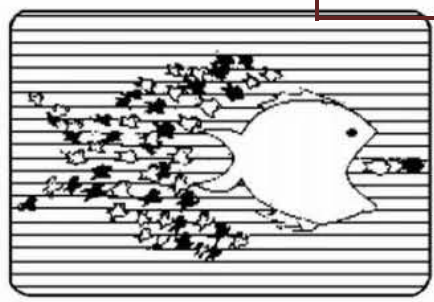

Eugene Kung 687-3006
James L. Quail 687-3034
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Barristers & Solicitors

Hasan Alam 687-3017
Articled Student

24 August 2011

Our File: 7485

Via Email: bchydroregulatorygroup@bchydro.com

Ms. Janet Fraser
Chief Regulatory Officer
British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Ms. Fraser:

Re: British Columbia Hydro and Power Authority
Certificate of Public Convenience and Necessity
for the Dawson Creek/Chetwynd Area Transmission Project
Project No.3698640
BCOAPO et. al Information Request #1

Further to Commission Order G-132-11, please find enclosed BCOAPO's Information Request No. 1.

Sincerely,
BC PUBLIC INTEREST ADVOCACY CENTRE

Eugene Kung
Barrister & Solicitor
Encl.

Cc: Registered Interveners

REQUESTOR NAME:	**BCOAPO**
INFORMATION REQUEST ROUND NO:	**#1**
TO:	**BRITISH COLUMBIA HYDRO & POWER AUTHORITY**
DATE:	**August 24, 2011**
PROJECT NO:	**3698640**
APPLICATION NAME:	**CPCN – Dawson Creek/Chetwynd Area Transmission Project**

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1 Page 2-19 makes reference to the existing load in the area. Appendix C of the System Planning Report (page 86) indicates that the current load in the Dawson Creek and Groundbirch area is roughly 100 MW. Please confirm that this is the case and, with reference to Figure 2-2, please indicate where this load is distributed within the area.

1.2 What is the load associated with the gas producers in the area that are currently BC Hydro customers.

1.2.1 Please confirm (per page 82) that these customer are currently served on an interruptible basis.

1.3 Are there any other current customers in area that are served on an interruptible basis?

1.4 Of the roughly 100 MW of current load, how much is served on an interruptible basis?

2.0 Reference: Exhibit B-1, page 2-9

Preamble: The Application distinguishes between those gas producers "who have indicated their intent to take service from BC Hydro" and those "who have indicated an interest but not yet made any formal commitments".

2.1 Please describe what entails "a formal commitment to take service".

2.2 What is the anticipated load (MW) associated with those gas producers who have made a formal commitment to take service?

3.0 Reference: Exhibit B-1, pages 2-13

3.1 Were any other local generation options considered besides wind (e.g. local gas-fired generation)? If not, why not? If yes, why were they rejected?

4.0 Reference: Exhibit B-1, pages 2-15 and 2-17

4.1 What are the comparative economics for a gas producer of using electric vs. direct gas compression?

5.0 Reference: Exhibit B-1, page 2-19 and System Planning Report (Appendix B), page 82 of 100

5.1 What is the total load (MW) associated with the five large producers that have requested service?

5.2 What is the total load for all customers who have "requested service"?

5.3 Is it anticipated that the balance of the (up to) 278 MW of the forecast gas producer load (per Appendix B, page 82) will be associated with producers requiring less than 10 MW? Alternatively, does BC Hydro expect that there will additional requests for service from gas producers seeking more than 10 MW of power?

5.3.1 If yes, will these customers also be required to provide "security" and how will the amount be determined.

5.4 The determination of the 40/60 split appears to only take into account the transmission requirements to meet the needs of the existing customers and the five large producers. Where and how are the capacity requirements and costs to meet the needs of either smaller (<10 MW producers) or larger producers that have not "requested service" taken into account in the determination of security requirements?

6.0 Reference: Exhibit B-1, pages 2-14; 3-4 to 3-6 and 3-10

6.1 Please provide a revised version of Figure 2-5 based on Alternative 1, showing the new N-0 and N-1 limits.

6.2 Please provide a revised version of Figure 2-5 based on Alternative 2, showing the new N-0 and N-1 limits.

6.3 The Application states (page 3-4) that Alternative 1 will increase the firm transmission capacity to 185 MW which will meet the forecasted load requirements for the next 30 years. Please reconcile this statement with the fact the load forecast for the area increases to roughly 300 MW over the next 30 years.

6.4 Please reconcile the 185 MW and 207 MW transmission capacity values reported on pages 3-4 and 3-6 for Alternatives 1 and 2 respectively with the 413 MW and 368 MW supply capability values reported on page 3-10.

7.0 Reference: Exhibit B-1, pages 3-8 to 3-9

7.1 At what value of energy (2011 $) is Alternative 2's present value less than that for Alternative 1?

7.2 Based on the $129/MWh value for losses, by what percentage would the gas producer load forecast have to be reduced in order for the present value of Alternative 1 to exceed that for Alternative 2?

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

8.1 Assuming that virtually all of the gas producer requirements for were met through direct gas compression such that the load forecast more closely tracked the "Other Forecast" in Figure 2-3, would there be any other transmission alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years?

8.1.1 If not, why not?

8.1.2 If yes, what are they? Please provide rough cost estimates for the two most viable.

8.2 Assuming that the gas producer requirements were as projected in the Low Scenario forecast, would there be any other transmission alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years?

8.2.1 If not, why not?

8.2.2 If yes, what are they? Please provide rough cost estimates for the two most viable.

9.0 Reference: Exhibit B-1, page 4-9

9.1 Please explain more fully the "higher constructability risk" associated with Option E1.

10.0 Reference: Exhibit B-1, page 4-11

10.1 Please explain more fully why Option C1 is considered to have a "lower constructability risk".

11.0 Reference: Exhibit B-1, page 5-3

11.1 Please confirm whether or not BC Hydro intends on adopting/implementing the various mitigation measures set out in Table 5-1 and whether or not the costs of these measures have been included in the Project's cost estimate.

12.0 Reference: Exhibit B-1, page 6-6

12.1 Please confirm that the Blueberry First Nation should also have been included in those First Nations identified through the CAD search. If not how was their potential interest identified?

13.0 Reference: Exhibit B-1, pages 6-10 to 6-13

13.1 Are any of the lands affected by the propose project ones where the Treaty 8 signatory First Nations currently have treaty rights as discussed at lines 1-7 of page 6-11?

13.1.1 If so, what lands and which First Nations are affected?

14.0 Reference: Exhibit B-1, page 7-3

14.1 Are the security requirements based on the forecast or the actual project costs?

15.0 Reference: Exhibit B-1, page 7-9

15.1 Given the definition of the P90 cost estimate, please explain why there is considered to be a “moderate probability” that the cost estimate will be exceeded.

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1.1 Page 2-19 makes reference to the existing load in the area. Appendix C of the System Planning Report (page 86) indicates that the current load in the Dawson Creek and Groundbirch area is roughly 100 MW. Please confirm that this is the case and, with reference to Figure 2-2, please indicate where this load is distributed within the area.

RESPONSE:

In the Load Forecast for F2011, the Dawson Creek and Groundbirch area winter load was approximately 100 MW distributed by three points of supply: 1) DAW, 2) SEP and 3) NL2/3/5 as shown in Figure 2-2 of Exhibit B-1.

The actual measured distribution load for F2011 was approximately 25 MW less than the forecast due to a gas compression plant not connecting in time for the winter load, a pulp mill exhibiting partial shutdown, and other gas customers maintaining the same load demand in the winter. Additionally, a transmission voltage customer connected to the Dawson Creek Area 138 kV Transmission System was short of its expected peak demand and area stations peaks did not coincide as may be expected. The F2012 load is expected to be in line with the forecast.

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1.2 What is the load associated with the gas producers in the area that are currently BC Hydro customers.

RESPONSE:

The load associated with the gas producers (conventional) in the area that are currently BC Hydro customers is approximately 55 MW.

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1.2.1 Please confirm (per page 82) that these customer are currently served on an interruptible basis.

RESPONSE:

New customers since 2009 with loads exceeding 1 MW are served on an interruptible basis. This was implemented as a mitigation strategy pending implementation of system upgrades to increase system capacity.

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1.3 Are there any other current customers in area that are served on an interruptible basis?

RESPONSE:

No, at this time there are not any other current customers served on an interruptible basis.

1.0 Reference: Exhibit B-1, System Planning Report (Appendix B), page 86
Exhibit B-1, pages 2-4 and 2-19

1.1.4 Of the roughly 100 MW of current load, how much is served on an interruptible basis?

RESPONSE:

Approximately 55 MW of transmission and distribution load is interruptible.

2.0 Reference: Exhibit B-1, page 2-9

The Application distinguishes between those gas producers "who have indicated their intent to take service from BC Hydro" and those "who have indicated an interest but not yet made any formal commitments".

1.2.1 Please describe what entails "a formal commitment to take service".

RESPONSE:

A formal commitment to take service means that the customer has signed an Electricity Supply Agreement (Transmission) and/or an Electricity Service Agreement (Distribution).

2.0 Reference: Exhibit B-1, page 2-9

The Application distinguishes between those gas producers "who have indicated their intent to take service from BC Hydro" and those "who have indicated an interest but not yet made any formal commitments".

1.2.2 What is the anticipated load (MW) associated with those gas producers who have made a formal commitment to take service?

RESPONSE:

The anticipated load associated with those gas producers who have made a formal commitment to take service and/or provided a letter of support is 181 MW. This does not include customers currently in service.

3.0 Reference: Exhibit B-1, pages 2-13

1.3.1 Were any other local generation options considered besides wind (e.g. local gas-fired generation)? If not, why not? If yes, why were they rejected?

RESPONSE:

No other local generation options were considered besides wind. Little consideration was given to local gas-fired generation for the reasons discussed in response to CEC IR 1.38.1.

4.0 Reference: Exhibit B-1, pages 2-15 and 2-17

1.4.1 What are the comparative economics for a gas producer of using electric vs. direct gas compression?

RESPONSE:

Please refer to the responses to BCUC IRs 1.38.4 and 1.43.1.

5.0 Reference: Exhibit B-1, page 2-19 and
System Planning Report (Appendix B), page 82 of 100

1.5.1 What is the total load (MW) associated with the five large producers that have requested service?

RESPONSE:

The total anticipated load (MW) associated with the five large customers that have requested service is 176 MW in the F2014 timeframe.

Please also refer to BCUC IR 1.38.2 with respect to how these customer loads are reflected in the Base Load forecast.

5.0 Reference: Exhibit B-1, page 2-19 and
System Planning Report (Appendix B), page 82 of 100

1.5.2 What is the total load for all customers who have "requested service"?

RESPONSE:

The load for customers in service, committed, or currently undertaking studies total 48 MW by 2021.

5.0 Reference: Exhibit B-1, page 2-19 and
System Planning Report (Appendix B), page 82 of 100

1.5.3 Is it anticipated that the balance of the (up to) 278 MW of the forecast gas producer load (per Appendix B, page 82) will be associated with producers requiring less than 10 MW? Alternatively, does BC Hydro expect that there will additional requests for service from gas producers seeking more than 10 MW of power?

RESPONSE:

BC Hydro agrees that the additional load will be comprised of customers with loads greater and less than 10 MW. The size distribution of customer loads will depend on the size of new customer loads, and possible producer consolidations in the region. BC Hydro has not forecast the extent to which this may occur.

5.0 Reference: Exhibit B-1, page 2-19 and
System Planning Report (Appendix B), page 82 of 100

1.5.3 Is it anticipated that the balance of the (up to) 278 MW of the forecast gas producer load (per Appendix B, page 82) will be associated with producers requiring less than 10 MW? Alternatively, does BC Hydro expect that there will additional requests for service from gas producers seeking more than 10 MW of power?

1.5.3.1 If yes, will these customers also be required to provide "security" and how will the amount be determined.

RESPONSE:

Please refer to the response to BCOAPO IR 1.5.4.

5.0 Reference: Exhibit B-1, page 2-19 and
System Planning Report (Appendix B), page 82 of 100

1.5.4 The determination of the 40/60 split appears to only take into account the transmission requirements to meet the needs of the existing customers and the five large producers. Where and how are the capacity requirements and costs to meet the needs of either smaller (<10 MW producers) or larger producers that have not "requested service" taken into account in the determination of security requirements?

RESPONSE:

Loads that are less than 10 MW will be served with the available capacity that is part of the DCAT Project.

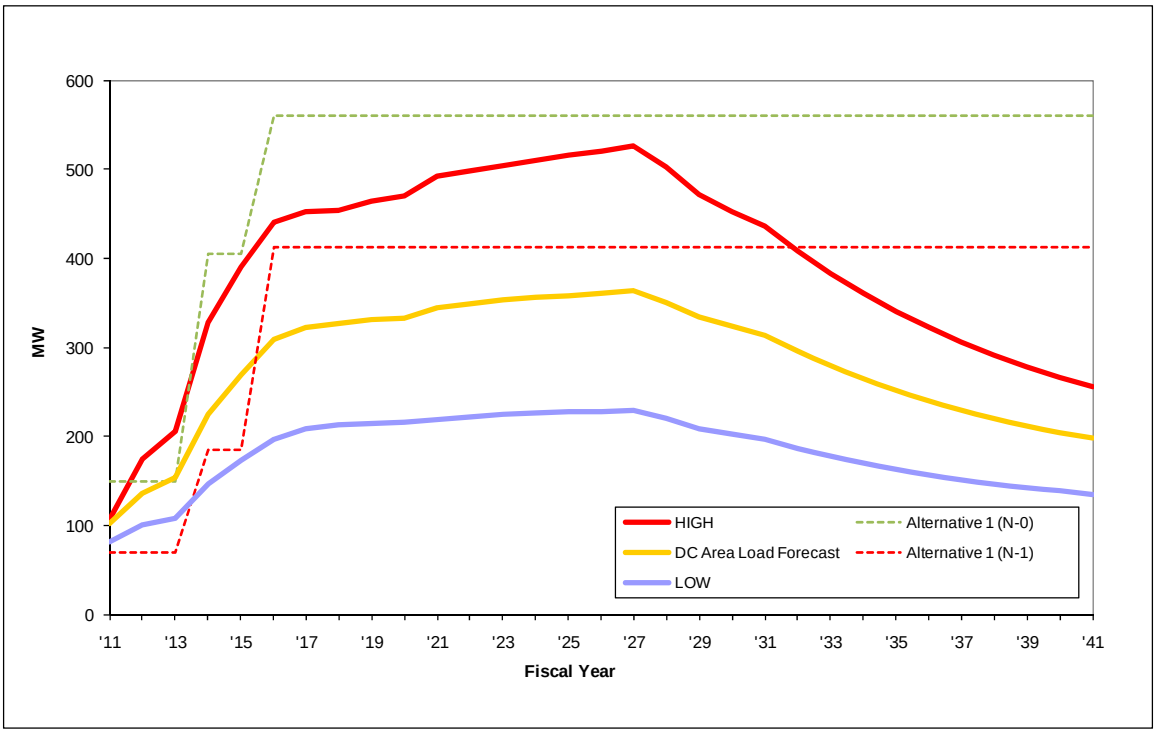
Any loads greater than 10 MW that have not yet requested service cannot likely be supplied until after additional capacity is made available by future upgrades. Security requirements in connection with customer loads will be determined based on the provision of the Electric Tariff at that time.

6.0 Reference: Exhibit B-1, pages 2-14; 3-4 to 3-6 and 3-10

1.6.1 Please provide a revised version of Figure 2-5 based on Alternative 1, showing the new N-0 and N-1 limits.

RESPONSE:

The following figure shows the N-0 and N-1 limits for Alternative 1 over the 30-year planning period. The limits change with the implementation of the DCAT Project in F2014 and thereafter inclusion of an F2016 stage for evaluation purposes.

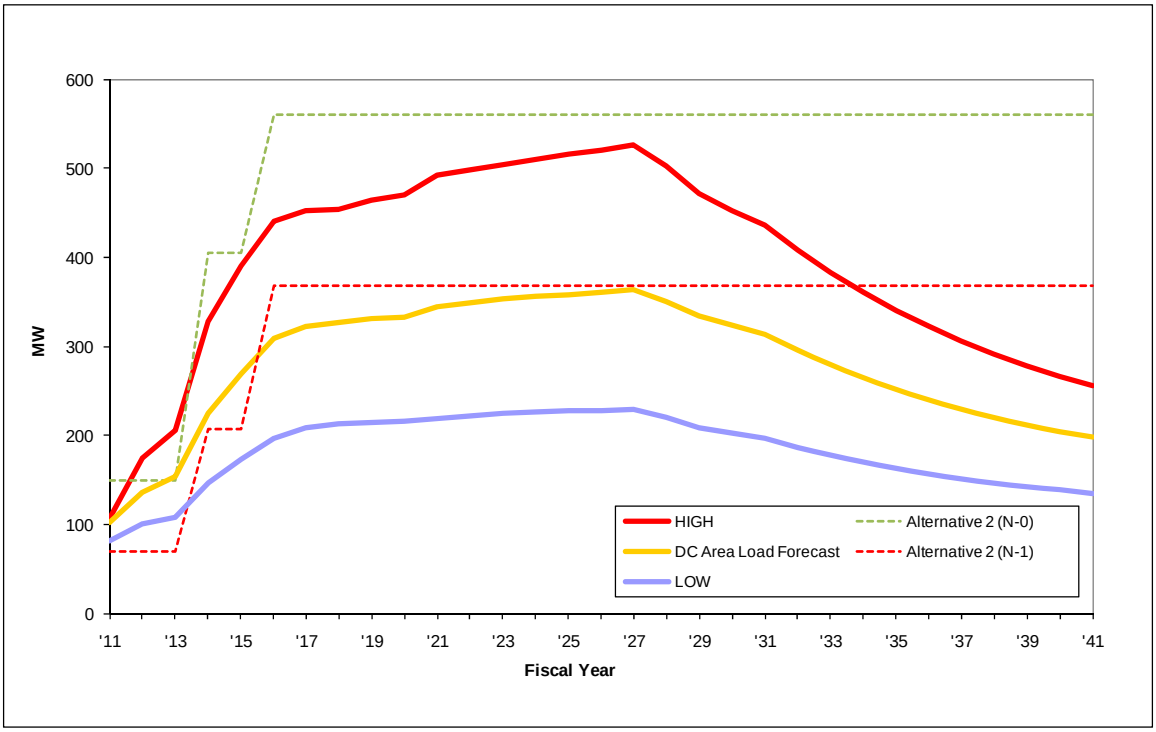


6.0 Reference: Exhibit B-1, pages 2-14; 3-4 to 3-6 and 3-10

1.6.2 Please provide a revised version of Figure 2-5 based on Alternative 2, showing the new N-0 and N-1 limits.

RESPONSE:

The following figure shows the N-0 and N-1 limits for Alternative 2 over the 30-year planning period. The limits change with the implementation of the DCAT Project in F2014 and thereafter inclusion of an F2016 stage for evaluation purposes.



6.0 Reference: Exhibit B-1, pages 2-14; 3-4 to 3-6 and 3-10

1.6.3 The Application states (page 3-4) that Alternative 1 will increase the firm transmission capacity to 185 MW which will meet the forecasted load requirements for the next 30 years. Please reconcile this statement with the fact the load forecast for the area increases to roughly 300 MW over the next 30 years.

RESPONSE:

The Application states (Exhibit B-1, page 3-4) that with implementation of an F2016 stage, Alternative 1 will meet the forecast of Dawson Creek and Groundbirch load supply requirements for the next 30 years.

On a stand-alone basis, the Project will increase the firm transmission capacity to 185 MW. An F2016 stage will increase the firm transmission capacity to meet the peak of the 30-year forecast.

For clarity, the Application is seeking approval of the DCAT Project only. An F2016 stage, as noted in the Application, is included for evaluation purpose only.

6.0 Reference: Exhibit B-1, pages 2-14; 3-4 to 3-6 and 3-10

1.6.4 Please reconcile the 185 MW and 207 MW transmission capacity values reported on pages 3-4 and 3-6 for Alternatives 1 and 2 respectively with the 413 MW and 368 MW supply capability values reported on page 3-10.

RESPONSE:

Prior to the implementation of an F2016 stage, Alternative 1 and 2 would have a transmission capacity of 185 MW and 207 MW respectively.

These transmission capacity values increase to 413 MW for Alternative 1 and 368 MW for Alternative 2 after the implementation of an F2016 stage.

7.0 Reference: Exhibit B-1, pages 3-8 to 3-9

1.7.1 At what value of energy (2011 $) is Alternative 2's present value less than that for Alternative 1?

RESPONSE:

Please refer to the response to BCUC IR 1.54.7.

7.0 Reference: Exhibit B-1, pages 3-8 to 3-9

1.7.2 Based on the $129/MWh value for losses, by what percentage would the gas producer load forecast have to be reduced in order for the present value of Alternative 1 to exceed that for Alternative 2?

RESPONSE:

Through interpolation, it is inferred that the Dawson Creek Area Load Forecast would need to be reduced by approximately 15 per cent for the present value of Alternative 1 to exceed that of Alternative 2.

If this reduction were all attributed to gas production, this would represent a 20 per cent reduction in the gas producer load forecast.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.1 Assuming that virtually all of the gas producer requirements for were met through direct gas compression such that the load forecast more closely tracked the "Other Forecast" in Figure 2-3, would there be any other transmission alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years?

RESPONSE:

Please refer to the response to BCUC IR 1.46.1.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.1 Assuming that virtually all of the gas producer requirements for were met through direct gas compression such that the load forecast more closely tracked the "Other Forecast" in Figure 2-3, would there be any other transmission alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years?

1.8.1.1 If not, why not?

RESPONSE:

Please refer to the response to BCUC IR 1.46.1.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.1.2 If yes, what are they? Please provide rough cost estimates for the two most viable.

RESPONSE:

Please refer to the response to BCUC IR 1.46.1.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.2 Assuming that the gas producer requirements were as projected in the Low Scenario forecast, would there be any other transmission alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years?

RESPONSE:

Yes. Please refer to the response to BCOAPO IR 1.8.2.2.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.2.1 If not, why not?

RESPONSE:

Please refer to the response to BCOAPO IR 1.8.2.2.

8.0 Reference: Exhibit B-1, Project Alternatives (Section 3)

1.8.2.2 If yes, what are they? Please provide rough cost estimates for the two most viable.

RESPONSE:

A conceptual review was undertaken to identify alternatives for meeting the load requirements of the Dawson Creek and Groundbirch area over the next 30 years assuming that the gas producer requirements were as projected in the Low Scenario forecast.

Two hypothetical alternatives were identified to restore N-1 reliability to the Dawson Creek 138 kV transmission system with order of magnitude estimates. Additional study would be required to do a complete evaluation of alternatives. These alternatives do not address N-1 reliability of the existing 230 kV system.

<u>Alternative 1</u>

Construct a new 55 km 138 kV line between TAY and DAW, and VAR compensation installed at BMT. Under this alternative the Groundbirch load would be supplied by the 230 kV system by a tap on 2L312 since the 138 kV system would not have sufficient capacity to supply both the Dawson Creek and Groundbirch loads.

Estimate: $60 million.

<u>Alternative 2</u>

Construct new 230-138 kV SLS at the intersection of the 230-138 kV systems approximately 20 km east of CWD, a new 138 kV line between SLS and BMT and VAR compensation at BMT.

Estimate: $70 million.

9.0 Reference: Exhibit B-1, page 4-9

1.9.1 Please explain more fully the "higher constructability risk" associated with Option E1.

RESPONSE:

Constructability risk was evaluated against general constructability issues (such as working near live lines or restricted construction, requirements for traffic management, etc.), new access required for construction, and soil conditions.

As compared to the other options, Options E1 has higher constructability risk associated with new access and soil conditions. Option E1 involves routing the line through marshy areas just east of the Alaska Highway, which restricts the construction to winter only in these areas.

BC Hydro notes that Option E3 has higher risk associated with general constructability issues as compared to the other alternatives. This is due to construction restrictions of building on the existing ROW while keeping existing lines in service. However, E3 was eliminated for other considerations including higher cost, as noted in the Application on page 4-9.

10.0 Reference: Exhibit B-1, page 4-11

1.10.1 Please explain more fully why Option C1 is considered to have a "lower constructability risk".

RESPONSE:

Options C3 and C2 were considered to have a higher general constructability risk than C1 because they both pass through areas of significant oil and gas development activity. This would place restrictions on equipment movement, safe distances, laydown areas and stringing operations. In addition, due to oil and gas activity, large number of permits would need to be obtained for crossing, and paralleling pipelines.

Option C3 passes through some potentially unstable terrain so the soil condition was considered less favourable than for options C1 and C2.

Access along C1 and C2 were considered better than for Option C3, as option C3 runs through a larger portion of relatively remote Crown land with limited access requiring more road construction. However, C1 is slightly better than C2 due to its proximity to the existing transmission line and Highway 97.

Considering all the above, C1 is considered to be a "lower constructability risk" that C2 or C3.

11.0 Reference: Exhibit B-1, page 5-3

1.11.1 Please confirm whether or not BC Hydro intends on adopting/implementing the various mitigation measures set out in Table 5-1 and whether or not the costs of these measures have been included in the Project's cost estimate.

RESPONSE:

BC Hydro intends to implement the mitigation measures set out in Table 5-1 where required. These measures will form the basis for the development of the construction EMP that all contractors will be required to follow. Please refer to section 5.8 (pages 5-23 to 5-25) of Exhibit B-1 for more information about the construction EMP. The costs to implement the construction EMP including its mitigation measures are included in the Project estimate.

12.0 Reference: Exhibit B-1, page 6-6

1.12.1 Please confirm that the Blueberry First Nation should also have been included in those First Nations identified through the CAD search. If not how was their potential interest identified?

RESPONSE:

The results of the CAD search are provided in Exhibit B-1, Appendix G, pages 1 to 3 of 171. As indicated, Blueberry River First Nation was not identified in this search. Please refer to the response to BCUC IR 1.4.1 for a description of the parameters used for this search.

Blueberry River First Nation was identified as a First Nation who may have Aboriginal interests in the area on the basis of the information sources described in Exhibit B-1, section 6.1.4.1.

13.0 Reference: Exhibit B-1, pages 6-10 to 6-13

1.13.1 Are any of the lands affected by the propose project ones where the Treaty 8 signatory First Nations currently have treaty rights as discussed at lines 1-7 of page 6-11?

RESPONSE:

The land affected by the Project is within the boundaries of Treaty 8. Please refer to section 6.1.6 of Exhibit B-1, pages 6-14 to 6-25 for a discussion of the consequent consultation process BC Hydro undertook with First Nations that are members of Treaty 8.

13.0 Reference: Exhibit B-1, pages 6-10 to 6-13

1.13.1.1 If so, what lands and which First Nations are affected?

RESPONSE:

Please refer to the response to BCOAPO IR 1.13.1.

14.0 Reference: Exhibit B-1, page 7-3

1.14.1 Are the security requirements based on the forecast or the actual project costs?

RESPONSE:

The security requirements are based on the P50 cost estimate for the Project. Please refer to Exhibit B-1, Appendix C.

15.0 Reference: Exhibit B-1, page 7-9

1.15.1 Given the definition of the P90 cost estimate, please explain why there is considered to be a "moderate probability" that the cost estimate will be exceeded.

RESPONSE:

Given that some of the control and mitigation strategies related to cost risk have been implemented (such as performing the Monte Carlo analysis, independent review of the cost estimate, and the planned use of blanket contracts), and that the risk is framed in relation to the P90 estimate, the correct probability for this risk at this time is "lower probability".

REQUESTOR NAME: **BC Sustainable Energy Association and Sierra Club of British Columbia**
INFORMATION REQUEST ROUND NO: 1
TO: **B.C. Hydro**
DATE: **August 24, 2011**
PROJECT NO: **3698640**
APPLICATION NAME: **Dawson Creek/Chetwynd Area Transmission Project**

1.0 Topic: Energy efficiency
Reference: Exhibit B-1, 2.3.4 Dawson Creek and Groundbirch Area Load Forecast

"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."

1.1 Is BC Hydro considering DSM for natural gas production load in the Dawson Creek and Groundbirch Area and elsewhere in the Province *at all*, i.e., as distinct from considering it in connection with this transmission upgrade project?

1.2 What assurances can BC Hydro provide that natural gas production electrical load enabled by approval of the proposed project will be met with the most efficient machinery possible?

2.0 Topic: Need
Reference: Exhibit B-1, Figure 2-4, Dawson Creek and Groundbirch Areas Load Forecast Including DSM

2.1 Please provide a version of Figure 2-4 that extends the graph to the left, i.e., showing actual load in previous years for, say, ten years.

3.0 Topic: Planning
Reference: Exhibit B-1, 2.4 Existing System Capacity Constraints

"...Figure 2–5 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 areas 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 Groundbirch and Dawson Creek areas."

3.1 Is it normal for BC Hydro to have a regional system that cannot serve the entire winter peak load on an N-1 basis, or that is two winters away from being unable to support the winter peak on an N-0 basis? If there are other instances, please list them.

3.2 If not, why did BC Hydro not apply for a CPCN for a transmission upgrade in the Dawson Creek/Chetwynd Area sooner?

4.0 Topic: Risk mitigation
Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 2.8 Proposed Tariff Revision

"BC Hydro acknowledges that, absent contractual limitations, natural gas producers may not choose to use electricity to meet their compression needs and that in consequence they will require significantly less electricity. To ensure that BC Hydro's existing customers are not exposed to undue risk in this regard, BC Hydro has canvassed industrial customers seeking more than 10 MW of power and requested that they provide security for their pro rata share of the costs of Project based on their forecast load. Each of the customers has indicated its willingness to provide security in this way.

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

"Tariff Supplement No. 6 provides for new customers paying the incremental costs of transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates." [underline added]

4.1 What is the relationship between the security to be provided by industrial customers to be served by the Project and the proposed Tariff Supplement No. 6? Will the security be replaced by Tariff Supplement No. 6? Are the two entirely different?

4.2 How is "the extent the projected revenue from their future rates do not cover those [transmission reinforcement] costs" determined? Please confirm that customers served by transmission reinforcement undertaken to serve their load will pay regular tariff rates for electricity they consume. If so, how does *any* portion of the rates they pay go toward covering the cost of the transmission reinforcement (except to the extent that *all* ratepayers cover the cost of transmission reinforcement)?

4.3 The discussion in section 2.8 talks about both *security* for the cost of transmission reinforcement and *recovery* of some of the costs of transmission reinforcement. Is BC Hydro proposing to *recover* 60 per cent of the Project costs from the five natural gas electrification load customers to be served by 60 per cent of the capacity of the Project? If not, why not?

4.4 Please provide examples of other situations in which BC Hydro has undertaken a transmission reinforcement project to meet electrical demand from prospective, rather than existing, customers. In those situations, did the prospective customers for which the transmission

reinforcement project was undertaken pay for the project? Did they provide security to cover the risk that they would not take the amount service they had requested?

5.0 Topic: Cost; Minister's Review
Reference: Exhibit B-1, 2.6 BC Hydro Corporate Objectives; 4.9 Estimate of Rate Impact

5.1 Please file the June 2011 Review of BC Hydro ("Minister's Review").

5.2 What are the implications of the Minister's Review for the Project, for example in terms of timing, cost and rate impacts?

5.3 The Application states that F2013 would be the first year in which BC Hydro's revenue requirement would be affected by the project [p.4-26]. Is BC Hydro proposing, i.e., in the F2013-F2014 RRA as filed, that the Project's F2013 and F2014 impact on the revenue requirement would be recovered in rates in those fiscal years? Has that changed, or will it change, as a result of BC Hydro's implementation of the Minister's Review?

6.0 Topic: Project justification
Reference: Exhibit B-1, 2. Project Justification

6.1 What is the minimum transmission upgrade in the Dawson Creek/Chetwynd Area that BC Hydro is legally obligated to provide, and what is the source of this legal obligation?

7.0 Topic: Stranded asset risk
Reference: Exhibit B-1, 2.5 Load Resource Balances; Figure 2-5 Load Forecast Scenarios; 2.5.2 Scenarios outside the Predicted Range; Appendix H, BCTC Public Engagement document, p.64 of 163

Figure 2-5 shows the High Load Forecast exceeding 500 MW (in approximately 2027) and the Low Load Forecast falling below 200 MW (in approximately 2031).

"There is a risk that all gas producers could choose to use gas compressors in which case the load growth could be even less than projected in the Low Scenario forecast." [p.2-15]

"- Risk of having stranded asset if the load growth or generation projects don't materialize; or conversely not having enough capacity if those requirements exceed the forecast"

7.1 Please define "stranded asset." Is there a technical distinction between a stranded asset and an underutilized asset?

7.2 Please discuss the risk of the Project becoming a stranded asset, or an underutilized asset.

7.3 Is it BC Hydro's proposal that ratepayers would bear the risk of the Project becoming a stranded asset, or an underutilized asset?

8.0 Topic: GHG emissions consequences
Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"Based on the expected electrical load from gas production that would be served via the Project, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C." [p.2-16]

8.1 Please provide or reference all the assumptions and calculations leading to the estimate of avoided/reduced GHG emissions of 1 million tonnes per year. Please include confirmation of the baseline GHG emissions against which the reduction is measured.

8.2 Please confirm that the amount of avoided/reduced GHG emissions per year due to the Project enabling electrification of natural gas production load would vary with the yearly amount of electrified natural gas production load.

8.3 Please provide a graph and corresponding table showing the Project's estimated avoided/reduced GHG emissions per year, to 2041. On the table, please also show cumulative GHG reductions; annual produced natural gas (produced with electric power provided by the Project), and the quantity of GHG emissions corresponding to combustion of the produced natural gas, per year and cumulative.

8.4 Please provide a graph and corresponding table showing B.C.'s legislated GHG reduction targets, B.C.'s forecast GHG emissions without the Project, and B.C.'s forecast GHG emissions *with* the Project over the planning period.

9.0 Topic: GHG emissions consequences
Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"There is potential for further avoided/reduced GHG emissions as future gas production in the Montney basin is electrified."

9.1 Please elaborate on this statement. Does this potential for further avoided/reduced GHG emissions apply to the Project as defined, or is it dependent on implementation of further phases of transmission upgrading?

10.0 Topic: GHG emissions consequences
Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive

to them and make the realization of the significant economic benefits identified above more likely.
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." [underline added]

10.1 Please provide an estimate of the incremental gas production that would be induced by embedded cost electricity provided by the Project. Please provide the corresponding GHG emissions due to combustion of this gas.

10.2 For comparison, please provide the GHG emissions from combustion of a unit of natural gas and the avoided/reduced GHG emissions from electrification of the production of a unit of natural gas.

10.3 The application talks about the potential scope of shale gas development in the Montney being vast, and natural gas gross revenues being approximately $4.5 billion per year at BC Hydro's forecast gas prices. Please provide a graph and corresponding table showing this quantity of gas and the GHG emissions associated with combustion of this gas over the planning period.

10.4 Given that BC Hydro justifies the Project in part by the avoided/reduced GHG emissions due to electrification of natural gas production load, how does BC Hydro reconcile that GHG benefit with the negative GHG emissions consequences of fostering a vast shale gas development?

10.5 Please comment on the proposition that if the Project did not proceed at all, or at a scale sufficient to electrify natural gas production load in the Montney Basin, the Project's contribution to tipping the balance in favour of natural gas production in certain situations would be reversed and the avoided GHG emissions from combustion of the avoided natural gas production would be greater than the avoided GHG emissions from electrification of the incremental natural production if the Project did proceed.

11.0 Topic: Effect on wind generation
Reference: Exhibit B-1, Appendix B, System Planning Report, Wind generation; Table 1-2: Near Term Wind Generation Projects Table 1-2: Near Term Wind Generation Projects

11.1 Please discuss the implications of the Project for Near Term Wind Generation Projects and potential future wind generation in the Dawson Creek/Chetwynd Area.

11.2 To the extent that approval and implementation of the Project builds electrical load in the Dawson Creek/Chetwynd Area is it reasonable to expect that new wind generation resources in the area would be evaluated with a lower or no discount for transmission losses to the Lower Mainland in comparison with other generation resources?

11.3 Would approval and implementation of the Project provide any benefit to potential wind generation sources in terms of reduced costs of incremental firm transmission?

12.0 Topic: Project staging
Reference: Exhibit B-1, 3.2.1 Project Staging; 3.2.4 Common F2016 Stage

12.1 Please describe the F2016 Stage at a high level, and provide a map showing both the Project and an illustrative configuration of the F2016 Stage.

12.2 Please confirm that BC Hydro would apply for a CPCN for the F2016 Stage. Does BC Hydro have an intended target date for a CPCN application for the F2016 Stage? If so, what is the target date? How much lead time does BC Hydro believe is necessary between a CPCN application and the desired in service date of the F2016 Stage?

13.0 Topic: Impacts on system
Reference: Exhibit B-1

13.1 Please discuss and quantify the induced natural gas production electrification load associated with the Project in relation to the BC Hydro integrated system load and load balance.

13.2 By how many months would the need for new generation resources be advanced, or pushed back, if the Project was approved, or the CPCN rejected?

14.0 Topic: Environmental project risk
Reference: Exhibit B-1, 7.7 Environmental Impacts of the Project; Appendix F, Environmental Overview Assessment

"Potential effects of the Project include the loss of habitat for fish, vegetation, and wildlife. However, if BMPs are implemented and work windows applied, the majority of Project effects can be reduced or eliminated for all disciplines." [p.192 of 207, pdf p. 538]

14.1 Did BC Hydro apply to the B.C. Environmental Assessment Office to voluntarily opt-in to the provincial environmental assessment process under subsection 7(1) of the B.C. *Environmental Assessment Act*? If not, why not?

14.2 On what basis will it be determined whether on-site environmental monitors will be engaged by BC Hydro or by contractors? When will that choice be made?

14.3 Does BC Hydro retain operational responsibility for auditing and monitoring implementation of the environmental management plan?

15.0 Topic: First Nations project risk
Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 6. First Nations Consultation and Public Engagement

15.1 To what extent does the Project budget fully incorporate costs associated with BC Hydro meeting obligations or commitments to First Nations? What is the risk of exceeding those cost estimates?

15.2 Does BC Hydro consider that its ability to obtain approval and to complete the Project is at risk due to First Nations issues? If so, what steps and procedures will be followed to address this risk?

1.0 Topic: Energy efficiency

Reference: Exhibit B-1, 2.3.4 Dawson Creek and Groundbirch Area Load Forecast

"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."

1.1.1 Is BC Hydro considering DSM for natural gas production load in the Dawson Creek and Groundbirch Area and elsewhere in the Province at all, i.e., as distinct from considering it in connection with this transmission upgrade project?

RESPONSE:

Yes, DSM for natural gas production load is included within the scope of the Power Smart New Plant Design program which is available to eligible BC Hydro customers.

1.0 Topic: Energy efficiency

Reference: Exhibit B-1, 2.3.4 Dawson Creek and Groundbirch Area Load Forecast

"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."

1.1.2 What assurances can BC Hydro provide that natural gas production electrical load enabled by approval of the proposed project will be met with the most efficient machinery possible?

RESPONSE:

BC Hydro is unable to provide assurances that natural gas production electrical load will be met with the most efficient machinery possible. However, BC Hydro aims to influence customer decisions about energy efficiency through its DSM programs and in this case by interacting with customers at the earliest design stage possible. In particular, the New Plant Design program encourages new and existing industrial customers to use energy efficient equipment in new plants and plant expansions.

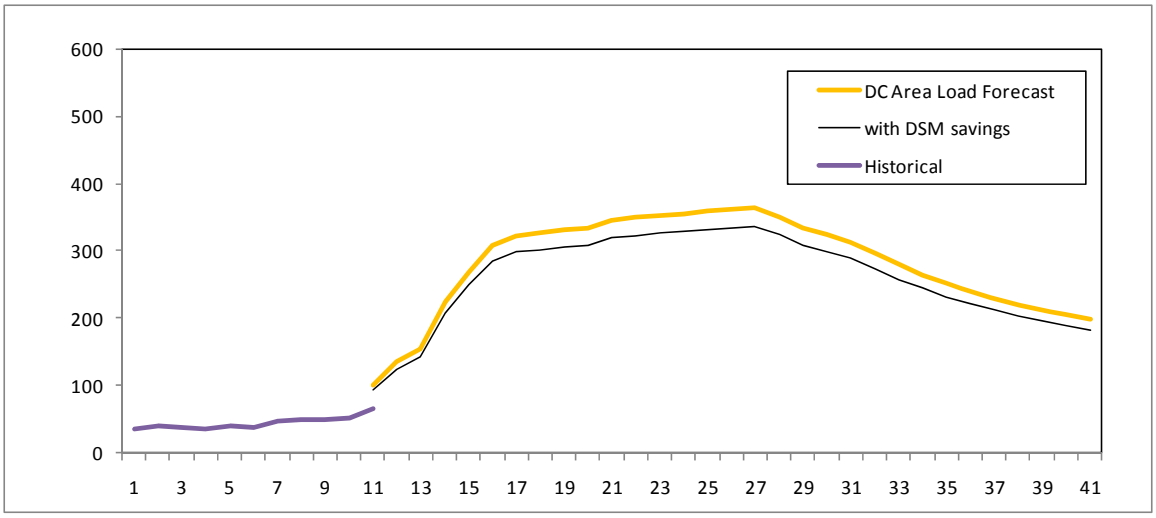
2.0 Topic: **Need**

Reference: **Exhibit B-1, Figure 2-4, Dawson Creek and Groundbirch Areas Load Forecast Including DSM**

1.2.1 Please provide a version of Figure 2-4 that extends the graph to the left, i.e., showing actual load in previous years for, say, ten years.

RESPONSE:

The following graph shows Figure 2-4 extended to include ten years of historical load data for the Dawson Creek and Groundbirch Areas.



Please refer to the response to BCOAPO IR 1.1.1 for an explanation of the gap between the forecast load in F2011, and the actual load measured in F2011.

3.0 Topic: Planning

Reference: Exhibit B-1, 2.4 Existing System Capacity Constraints

"...Figure 2–5 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 areas 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 Groundbirch and Dawson Creek areas."

1.3.1 Is it normal for BC Hydro to have a regional system that cannot serve the entire winter peak load on an N-1 basis, or that is two winters away from being unable to support the winter peak on an N-0 basis? If there are other instances, please list them.

RESPONSE:

BC Hydro's regional planning criterion is to ensure reliability of supply at an N-1 level for non-radial systems. BC Hydro endeavours to ensure appropriate system upgrades are identified in a timely way to ensure implementation before reliability standards are compromised. Depending on the pace of extraordinary load growth, such as in the South Peace region, interim measures may be necessary to maintain supply, including curtailment, in the event significant transmission system upgrades are necessary but cannot be implemented in time to ensure N-1 performance.

There are no other large scale projects identified to address N-1 deficiencies similar to the Dawson Creek area. Smaller projects that may be necessary to address minor N-1 deficiencies, if any, are identified through BC Hydro's system planning process, and are implemented as part of BC Hydro's capital plan expenditures, as required.

3.0 Topic: Planning

Reference: Exhibit B-1, 2.4 Existing System Capacity Constraints

"...Figure 2–5 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 areas 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 Groundbirch and Dawson Creek areas."

1.3.2 If not, why did BC Hydro not apply for a CPCN for a transmission upgrade in the Dawson Creek/Chetwynd Area sooner?

RESPONSE:

The pace of actual and forecast load growth in the region is unprecedented as is illustrated graphically in the response to BCSEA IR 1.2.1. Neither industry nor BC Hydro previously anticipated the pace of development that is now expected.

4.0 Topic: Risk mitigation

Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 2.8 Proposed Tariff Revision

"BC Hydro acknowledges that, absent contractual limitations, natural gas producers may not choose to use electricity to meet their compression needs and that in consequence they will require significantly less electricity. To ensure that BC Hydro's existing customers are not exposed to undue risk in this regard, BC Hydro has canvassed industrial customers seeking more than 10 MW of power and requested that they provide security for their pro rata share of the costs of Project based on their forecast load. Each of the customers has indicated its willingness to provide security in this way.

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

"Tariff Supplement No. 6 provides for new customers paying the incremental costs of transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates." [underline added]

1.4.1 What is the relationship between the security to be provided by industrial customers to be served by the Project and the proposed Tariff Supplement No. 6? Will the security be replaced by Tariff Supplement No. 6? Are the two entirely different?

RESPONSE:

With respect to transmission voltage customers, Electric Tariff Supplement No. 6 applies without change to determine the amount of the security to be provided.

With respect to distribution voltage customers with loads greater than 10 MW, the Application includes a revision to the Electric Tariff to provide for the same security requirement for transmission system reinforcement as those transmission customers supplied under Electric Tariff Supplement No. 6.

4.0 Topic: Risk mitigation

Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 2.8 Proposed Tariff Revision

"BC Hydro acknowledges that, absent contractual limitations, natural gas producers may not choose to use electricity to meet their compression needs and that in consequence they will require significantly less electricity. To ensure that BC Hydro's existing customers are not exposed to undue risk in this regard, BC Hydro has canvassed industrial customers seeking more than 10 MW of power and requested that they provide security for their pro rata share of the costs of Project based on their forecast load. Each of the customers has indicated its willingness to provide security in this way.

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

"Tariff Supplement No. 6 provides for new customers paying the incremental costs of transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates." [underline added]

1.4.2 How is "the extent the projected revenue from their future rates do not cover those [transmission reinforcement] costs" determined? Please confirm that customers served by transmission reinforcement undertaken to serve their load will pay regular tariff rates for electricity they consume. If so, how does any portion of the rates they pay go toward covering the cost of the transmission reinforcement (except to the extent that all ratepayers cover the cost of transmission reinforcement)?

RESPONSE:

Please refer to the response to BCUC IR 1.48.2 for a discussion on how Electric Tariff Supplement No. 6 treats projected revenues and costs. Transmission voltage customers will be supplied electricity under the approved tariff (Rate Schedule 1823) and the revenues received are used to reduce the required security.

If approved and implemented, then the cost of the DCAT Project will be included in BC Hydro's revenue requirements.

4.0 Topic: Risk mitigation

Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 2.8 Proposed Tariff Revision

"BC Hydro acknowledges that, absent contractual limitations, natural gas producers may not choose to use electricity to meet their compression needs and that in consequence they will require significantly less electricity. To ensure that BC Hydro's existing customers are not exposed to undue risk in this regard, BC Hydro has canvassed industrial customers seeking more than 10 MW of power and requested that they provide security for their pro rata share of the costs of Project based on their forecast load. Each of the customers has indicated its willingness to provide security in this way.

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

"Tariff Supplement No. 6 provides for new customers paying the incremental costs of transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates." [underline added]

1.4.3 The discussion in section 2.8 talks about both security for the cost of transmission reinforcement and recovery of some of the costs of transmission reinforcement. Is BC Hydro proposing to recover 60 per cent of the Project costs from the five natural gas electrification load customers to be served by 60 per cent of the capacity of the Project? If not, why not?

RESPONSE:

Yes. BC Hydro expects to recover costs. Based on the application of Electric Tariff Supplement No.6, the estimated revenues from the five customers are sufficient to offset 60 per cent of the cost of the Project.

Please refer to the response to BCUC IR 1.48.2.

4.0 Topic: Risk mitigation

Reference: Exhibit B-1, 2.7 Risks and Risk Mitigation; 2.8 Proposed Tariff Revision

"BC Hydro acknowledges that, absent contractual limitations, natural gas producers may not choose to use electricity to meet their compression needs and that in consequence they will require significantly less electricity. To ensure that BC Hydro's existing customers are not exposed to undue risk in this regard, BC Hydro has canvassed industrial customers seeking more than 10 MW of power and requested that they provide security for their pro rata share of the costs of Project based on their forecast load. Each of the customers has indicated its willingness to provide security in this way.

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

"Tariff Supplement No. 6 provides for new customers paying the incremental costs of transmission reinforcement undertaken to serve their load to the extent the projected revenue from their future rates do not cover those costs. Customers are also required to post security equal to the revenue they are projected to contribute through rates." [underline added]

1.4.4 Please provide examples of other situations in which BC Hydro has undertaken a transmission reinforcement project to meet electrical demand from prospective, rather than existing, customers. In those situations, did the prospective customers for which the transmission reinforcement project was undertaken pay for the project? Did they provide security to cover the risk that they would not take the amount service they had requested?

RESPONSE:

Electric Tariff Supplement No. 6 has been applied numerous times since it was approved in 1991, to supply new transmission voltage customers. In some cases there was no system reinforcement required. In cases where a system reinforcement was required, customers provided security in support of the system reinforcement. Where future revenues were not anticipated to cover BC Hydro's costs, customers have been required to make contributions to the costs. In all these cases Electric Tariff Supplement No. 6 was the basis for the treatment of each customer.

More generally, BC Hydro implements system upgrades to meet projected load growth and service obligations.

5.0 Topic: **Cost; Minister's Review**

Reference: **Exhibit B-1, 2.6 BC Hydro Corporate Objectives; 4.9 Estimate of Rate Impact**

1.5.1 Please file the June 2011 Review of BC Hydro ("Minister's Review").

RESPONSE:

The June 2011 Review of BC Hydro is attached as Appendix 1 to Exhibit C4-2.

5.0 Topic: Cost; Minister's Review

Reference: Exhibit B-1, 2.6 BC Hydro Corporate Objectives; 4.9 Estimate of Rate Impact

1.5.2 What are the implications of the Minister's Review for the Project, for example in terms of timing, cost and rate impacts?

RESPONSE:

Please refer to the response to COPE IR 1.3.1.

5.0 Topic: Cost; Minister's Review

Reference: Exhibit B-1, 2.6 BC Hydro Corporate Objectives; 4.9 Estimate of Rate Impact

1.5.3 The Application states that F2013 would be the first year in which BC Hydro's revenue requirement would be affected by the project [p.4-26]. Is BC Hydro proposing, i.e., in the F2013-F2014 RRA as filed, that the Project's F2013 and F2014 impact on the revenue requirement would be recovered in rates in those fiscal years? Has that changed, or will it change, as a result of BC Hydro's implementation of the Minister's Review?

RESPONSE:

At this time, BC Hydro still proposes that the Project's impact on its F2013 and F2014 revenue requirement will be recovered in rates beginning in these fiscal years.

6.0 Topic: Project justification

Reference: Exhibit B-1, 2. Project Justification

1.6.1 What is the minimum transmission upgrade in the Dawson Creek/Chetwynd Area that BC Hydro is legally obligated to provide, and what is the source of this legal obligation?

RESPONSE:

BC Hydro's service obligations are established by the *Utilities Commission Act (UCA)*. Section 38 of the UCA indicates that the utility must provide and maintain facilities to provide service to the public that is "…adequate, safe, efficient, just and reasonable." Further under section 39 of the UCA the utility must provide suitable service without undue discrimination or delay to all persons who apply for service, are reasonably entitled to it and pay the rates established for that service.

Also, as noted at page 2-18 of Exhibit B-1, the BCUC must consider and be guided by the government's objective of encouraging utilities to develop adequate infrastructure in the time required to serve persons who receive or may receive service from the public utility (section 2.1 of SD No. 9).

BC Hydro has put forward an Application for the DCAT Project to address current capacity constraints in the Peace region transmission system. Without the Project, BC Hydro will not be able to meet customer requests for electricity service. The Project is scoped to meet near term growth requirement while establishing an adequate and efficient system to support future upgrades needed to address significant anticipated growth in the region.

7.0 Topic: Stranded asset risk

Reference: Exhibit B-1, 2.5 Load Resource Balances; Figure 2-5 Load Forecast Scenarios; 2.5.2 Scenarios outside the Predicted Range; Appendix H, BCTC Public Engagement document, p.64 of 163

Figure 2-5 shows the High Load Forecast exceeding 500 MW (in approximately 2027) and the Low Load Forecast falling below 200 MW (in approximately 2031).

"There is a risk that all gas producers could choose to use gas compressors in which case the load growth could be even less than projected in the Low Scenario forecast." [p.2-15]

"- Risk of having stranded asset if the load growth or generation projects don't materialize; or conversely not having enough capacity if those requirements exceed the forecast"

1.7.1 Please define "stranded asset." Is there a technical distinction between a stranded asset and an underutilized asset?

RESPONSE:

A stranded asset is an asset which is deemed to have reached the end of its useful economic life before all capital costs are fully recovered from customers.

Underutilized assets are assets that are still used and useful despite the fact that the asset is not fully utilized relative to their design specifications. Stranded assets are no longer used and useful.

7.0 Topic: Stranded asset risk

Reference: Exhibit B-1, 2.5 Load Resource Balances; Figure 2-5 Load Forecast Scenarios; 2.5.2 Scenarios outside the Predicted Range; Appendix H, BCTC Public Engagement document, p.64 of 163

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"- Risk of having stranded asset if the load growth or generation projects don't materialize; or conversely not having enough capacity if those requirements exceed the forecast"

1.7.2 Please discuss the risk of the Project becoming a stranded asset, or an underutilized asset.

RESPONSE:

The risk of the Project becoming an underutilized asset is discussed in Exhibit B-1, section 2.7, pages 2-18 and 2-19. The section notes that security from large industrial customers seeking more than 10 MW of power is being put in place to ensure ratepayers are not exposed to undue risk of the load not materializing.

As set out in the Application, the ability to service the load forecasted and anticipated during the forecast period of 30 years requires additional system upgrades beyond the DCAT Project. There is little risk that the transmission system capacity improvements achieved by the upgrades implemented as part of the DCAT Project alone will be stranded or underutilized in the long run.

7.0 Topic: Stranded asset risk

Reference: Exhibit B-1, 2.5 Load Resource Balances; Figure 2-5 Load Forecast Scenarios; 2.5.2 Scenarios outside the Predicted Range; Appendix H, BCTC Public Engagement document, p.64 of 163

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"- Risk of having stranded asset if the load growth or generation projects don't materialize; or conversely not having enough capacity if those requirements exceed the forecast"

1.7.3 Is it BC Hydro's proposal that ratepayers would bear the risk of the Project becoming a stranded asset, or an underutilized asset?

RESPONSE:

To ensure BC Hydro's existing customers are not exposed to undue risk, BC Hydro has requested that gas producers provide security for their pro rata share of the costs of the Project based on their forecasted load. For further information, please refer to section 2.7 of Exhibit B-1 (pages 2-18 and 2-19).

8.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"Based on the expected electrical load from gas production that would be served via the Project, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C." [p.2-16]

1.8.1 Please provide or reference all the assumptions and calculations leading to the estimate of avoided/reduced GHG emissions of 1 million tonnes per year. Please include confirmation of the baseline GHG emissions against which the reduction is measured.

RESPONSE:

The premise is that there would be an avoidance/reduction in GHG emissions (CO_2) being vented as a result of work otherwise provided by natural gas driven compressors being replaced by clean electricity supply. This premise assumes that, absent electric supply, industry would self-supply the work load. The calculation underlying the one million tonne per year estimate is approximate.

The estimated avoided/reduced emissions can be calculated with the following formula:

CO2 reduction (tonnes/year):

= Electrical demand (GWh/year) x direct gas drive compressor heat rate x (gigajoules/GWh) x natural gas combustion CO2 rate (tonnes/gigajoule)

= 1962 x 11,200 x 0.056

= 1,230,566 tonnes/year, rounded to 1 Mt/year.

The underlying assumptions are:

1962 GWh/year = Maximum expected electrical load service (GWh) to gas producers operating in the Groundbirch/Dawson Creek areas of the Montney gas basin. The baseline is the incremental gas sector Groundbirch/Dawson electric load (Reference: Exhibit B-1, Appendix B, page 82, Table 1 – Expected Annual Gas Production and Electricity Demand, GWh in F2027). As noted in the Application, future transmission upgrades are required beyond the DCAT Project to realize the 30-year forecast scenario.

11,200 GJ/GWh = approximate average heat rate of gas compression being replaced. This heat rate was provided by industry and is based on a 2500 hp direct drive natural gas-fired compressor.

0.056 t/GJ = approximate CO_2 produced in the combustion of natural gas. This estimate was derived from a list of coefficients provided by the US Energy Information Agency, and converted to metric units.

BC Hydro notes that the reference quotation from Exhibit B-1, page 2-16, requires modification. It should read:

> **"Based on the expected electrical load from gas production that would be served via the Project and future upgrades, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C."**

8.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"Based on the expected electrical load from gas production that would be served via the Project, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C." [p.2-16]

1.8.2 Please confirm that the amount of avoided/reduced GHG emissions per year due to the Project enabling electrification of natural gas production load would vary with the yearly amount of electrified natural gas production load.

RESPONSE:

Confirmed.

8.0 Topic: GHG emissions consequences

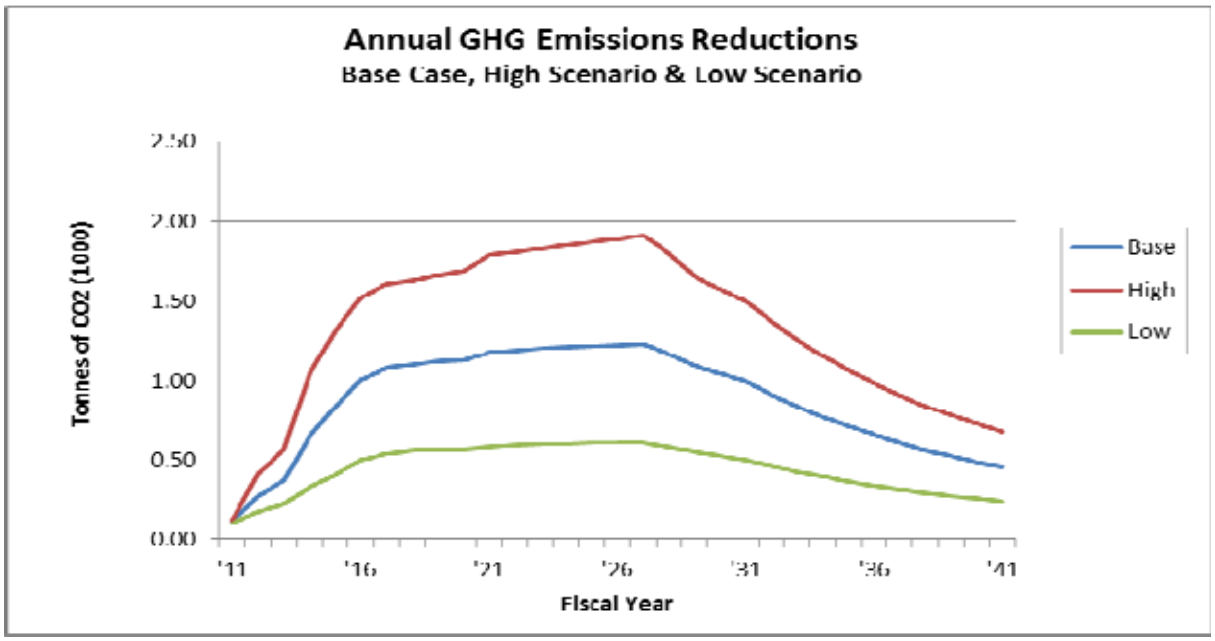
Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

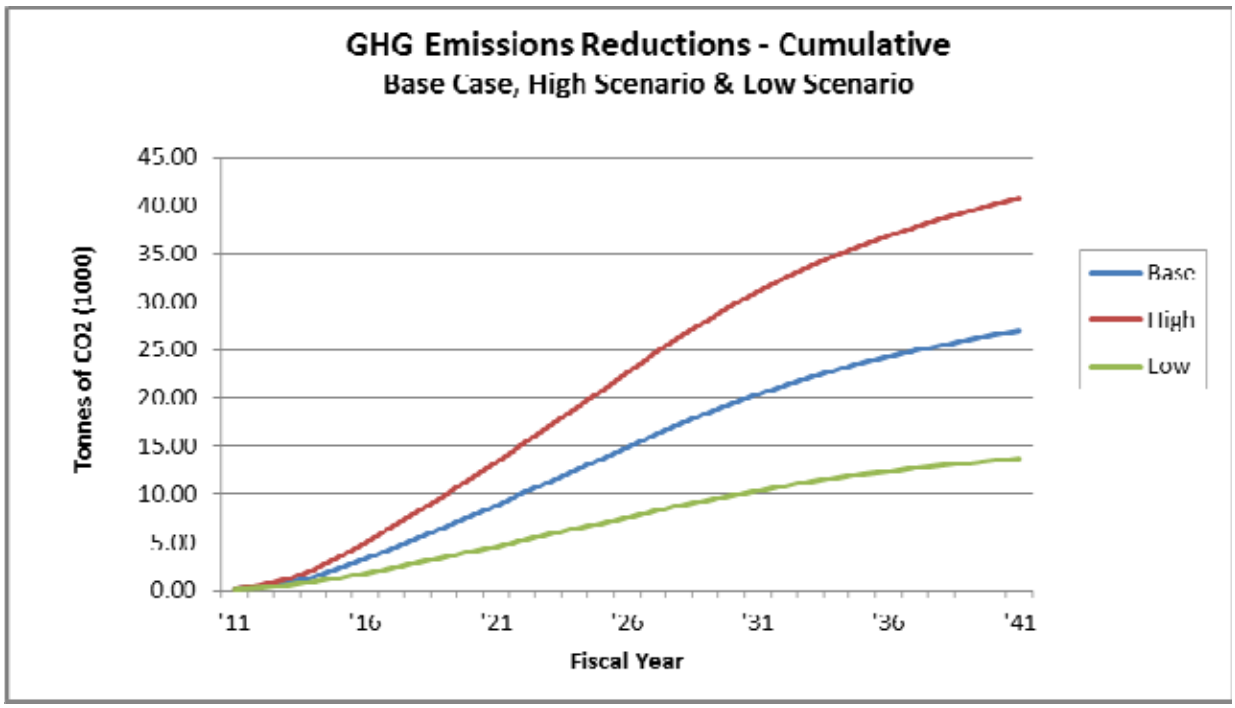
"Based on the expected electrical load from gas production that would be served via the Project, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C." [p.2-16]

1.8.3 Please provide a graph and corresponding table showing the Project's estimated avoided/reduced GHG emissions per year, to 2041. On the table, please also show cumulative GHG reductions; annual produced natural gas (produced with electric power provided by the Project), and the quantity of GHG emissions corresponding to combustion of the produced natural gas, per year and cumulative.

RESPONSE:

The chart and table shows the forecast reduction in GHG emissions for the various scenarios.





Fiscal Year	1 Gas Production Scenarios (GWh)			2 Heat Rate (GJ/GWh)	3 CO2 (Tons/GJ)	4 = (3 x 4 5/1000) Annual Emission Reductions (MT of CO2)			5 Cumulative Emission Reductions (MT of CO2)		
	Base	High	Low			Base	High	Low	Base	High	Low
F2011	191	199	163	11.2	0.056	0.12	0.12	0.10	0.12	0.12	0.10
F2012	439	657	281	11.2	0.056	0.28	0.41	0.18	0.40	0.54	0.28
F2013	593	906	356	11.2	0.056	0.37	0.57	0.22	0.77	1.11	0.50
F2014	1,035	1,667	527	11.2	0.056	0.65	1.05	0.33	1.42	2.15	0.83
F2015	1,325	2,082	647	11.2	0.056	0.83	1.31	0.41	2.25	3.46	1.24
F2016	1,597	2,426	794	11.2	0.056	1.00	1.52	0.50	3.25	4.98	1.74
F2017	1,714	2,561	866	11.2	0.056	1.08	1.61	0.54	4.32	6.58	2.28
F2018	1,757	2,592	898	11.2	0.056	1.10	1.63	0.56	5.43	8.21	2.84
F2019	1,780	2,653	906	11.2	0.056	1.12	1.66	0.57	6.54	9.87	3.41
F2020	1,792	2,688	910	11.2	0.056	1.12	1.69	0.57	7.67	11.56	3.98

Fiscal Year	1 Gas Production Scenarios (GWh)			2 Heat Rate (GJ/GWh)	3 CO2 (Tons/GJ)	4 = (3 x 4 5/1000) Annual Emission Reductions (MT of CO2)			5 Cumulative Emission Reductions (MT of CO2)		
	Base	High	Low			Base	High	Low	Base	High	Low
F2021	1,870	2,847	935	11.2	0.056	1.17	1.79	0.59	8.84	13.35	4.57
F2022	1,892	2,880	947	11.2	0.056	1.19	1.81	0.59	10.03	15.15	5.16
F2023	1,915	2,913	964	11.2	0.056	1.20	1.83	0.60	11.23	16.98	5.77
F2024	1,927	2,946	968	11.2	0.056	1.21	1.85	0.61	12.43	18.83	6.37
F2025	1,938	2,979	972	11.2	0.056	1.22	1.87	0.61	13.65	20.69	6.98
F2026	1,950	3,012	976	11.2	0.056	1.22	1.89	0.61	14.87	22.58	7.60
F2027	1,962	3,045	979	11.2	0.056	1.23	1.91	0.61	16.10	24.49	8.21
F2028	1,858	2,870	929	11.2	0.056	1.17	1.80	0.58	17.27	26.29	8.79
F2029	1,743	2,645	881	11.2	0.056	1.09	1.66	0.55	18.36	27.95	9.35
F2030	1,661	2,510	840	11.2	0.056	1.04	1.57	0.53	19.40	29.53	9.87
F2031	1,587	2,388	803	11.2	0.056	1.00	1.50	0.50	20.40	31.02	10.38
F2032	1,456	2,187	739	11.2	0.056	0.91	1.37	0.46	21.31	32.40	10.84
F2033	1,337	2,006	681	11.2	0.056	0.84	1.26	0.43	22.15	33.65	11.27
F2034	1,230	1,843	629	11.2	0.056	0.77	1.16	0.39	22.92	34.81	11.66
F2035	1,135	1,697	583	11.2	0.056	0.71	1.06	0.37	23.63	35.88	12.03
F2036	1,048	1,565	541	11.2	0.056	0.66	0.98	0.34	24.29	36.86	12.37
F2037	971	1,447	503	11.2	0.056	0.61	0.91	0.32	24.90	37.76	12.68
F2038	901	1,340	468	11.2	0.056	0.56	0.84	0.29	25.47	38.60	12.98
F2039	838	1,244	438	11.2	0.056	0.53	0.78	0.27	25.99	39.38	13.25
F2040	781	1,157	410	11.2	0.056	0.49	0.73	0.26	26.48	40.11	13.51
F2041	730	1,079	385	11.2	0.056	0.46	0.68	0.24	26.94	40.79	13.75
2 - Average Heat Rate of 2,500 hp Direct Drive Compressor											
3 - CO2 Content											

8.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"Based on the expected electrical load from gas production that would be served via the Project, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C." [p.2-16]

1.8.4 Please provide a graph and corresponding table showing B.C.'s legislated GHG reduction targets, B.C.'s forecast GHG emissions without the Project, and B.C.'s forecast GHG emissions with the Project over the planning period.

RESPONSE:

The B.C. *Greenhouse Gas Reduction Targets Act* (GGRTA) sets legislated targets for reducing greenhouse gases. Under the Act, B.C.'s GHG emissions are to be reduced by at least 33 per cent below 2007 levels by 2020. Interim reduction targets of 6 per cent by 2012 and 18 per cent by 2016 will guide and measure progress. A further emission-reduction target of 80 per cent below 2007 levels is required for 2050.

BC Hydro does not know how GHG emissions associated with gas sector activity in the Montney region are being accounted for in the provincial GHG emissions forecast. As such, GHG emissions related to providing electric service to the gas sector via the DCAT Project have been characterized as reduced emissions or avoided emissions.

9.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (a) Reduce B.C. GHG emissions

"There is potential for further avoided/reduced GHG emissions as future gas production in the Montney basin is electrified."

1.9.1 Please elaborate on this statement. Does this potential for further avoided/reduced GHG emissions apply to the Project as defined, or is it dependent on implementation of further phases of transmission upgrading?

RESPONSE:

To the extent increased gas sector development in the region can be served with clean electricity supply, there would be an avoidance/reduction in GHG emissions as a result of work otherwise provided by natural gas driven compressors.

The statement is used in reference to the base case gas producers forecast. The potential for further avoided/reduced GHG emissions reflects the potential for increase gas production that is electrified, as may be represented by the high load forecast. Future transmission upgrades are required beyond the DCAT Project to realize the 30-year forecast scenarios.

10.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive to them and make the realization of the significant economic benefits identified above more likely.

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." [underline added]

1.10.1 Please provide an estimate of the incremental gas production that would be induced by embedded cost electricity provided by the Project. Please provide the corresponding GHG emissions due to combustion of this gas.

RESPONSE:

BC Hydro does not have such an estimate. The statement was intended to be conceptual in nature.

10.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive to them and make the realization of the significant economic benefits identified above more likely.

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." [underline added]

1.10.2 For comparison, please provide the GHG emissions from combustion of a unit of natural gas and the avoided/reduced GHG emissions from electrification of the production of a unit of natural gas.

RESPONSE:

The formula for calculating the requested information is provided in the response to BCSEA IR 1.8.1.

10.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive to them and make the realization of the significant economic benefits identified above more likely.

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." [underline added]

1.10.3 The application talks about the potential scope of shale gas development in the Montney being vast, and natural gas gross revenues being approximately $4.5 billion per year at BC Hydro's forecast gas prices. Please provide a graph and corresponding table showing this quantity of gas and the GHG emissions associated with combustion of this gas over the planning period.

RESPONSE:

Please refer to the response to BCSEA IR 1.8.3.

10.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive to them and make the realization of the significant economic benefits identified above more likely.

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." [underline added]

1.10.4 Given that BC Hydro justifies the Project in part by the avoided/reduced GHG emissions due to electrification of natural gas production load, how does BC Hydro reconcile that GHG benefit with the negative GHG emissions consequences of fostering a vast shale gas development?

RESPONSE:

The production from the Montney gas basin is likely to be exported to other jurisdictions (U.S., Asia) and the utilization (combustion) of the increased production is unlikely to have any impact on GHG emissions in British Columbia. There are likely to be positive GHG consequences in other jurisdictions as the increased availability of natural gas will enable the displacement of higher emission energy sources (coal in the U.S. and coal and oil in Asia).

10.0 Topic: GHG emissions consequences

Reference: Exhibit B-1, 2.6.1 Energy Objectives (c) Encourage Economic Development…, p.2-17

"By providing industry with a choice of natural gas or electricity, BC Hydro will make a positive contribution to the overall economics of development in the Montney basin. Those producers that choose to sign up to purchase electricity will do so because they have concluded that it is advantageous in the long term. That in turn will make investment in the Montney and its reserves more attractive to them and make the realization of the significant economic benefits identified above more likely.

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." [underline added]

1.10.5 Please comment on the proposition that if the Project did not proceed at all, or at a scale sufficient to electrify natural gas production load in the Montney Basin, the Project's contribution to tipping the balance in favour of natural gas production in certain situations would be reversed and the avoided GHG emissions from combustion of the avoided natural gas production would be greater than the avoided GHG emissions from electrification of the incremental natural production if the Project did proceed.

RESPONSE:

If the Project did not proceed, then the absence of reasonably priced electricity as an energy source may tip the balance away from development in particular circumstances. Reduced production, however, may increase GHG emissions in other jurisdictions if other, higher emission fuels are used instead. If the production is exported, then the impact on emissions in British Columbia will be from the increased use of gas compression. It can be expected that GHG emissions will be greater in a scenario where the project does not proceed.

11.0 Topic: **Effect on wind generation**

Reference: **Exhibit B-1, Appendix B, System Planning Report, Wind generation; Table 1-2: Near Term Wind Generation Projects Table 1-2: Near Term Wind Generation Projects**

1.11.1 Please discuss the implications of the Project for Near Term Wind Generation Projects and potential future wind generation in the Dawson Creek/Chetwynd Area.

RESPONSE:

The DCAT Project would add transmission capacity to the Dawson Creek, Groundbirch and Chetwynd areas. This would be consistent with increasing system capacity to integrate future wind generation in these areas. In addition, the DCAT Project is aligned with future plans to add redundancy to the existing 230 kV supply from GMS to the new SLS Substation. This would increase the reliability of the near term wind generation projects and would be consistent with integrating future wind generation along the 230 kV transmission corridor between GMS and TLR.

With the DCAT Project in place, the existing Peace Regional 230 kV system would gain another connection to the grid at the new SLS Substation. On the loss of the 230 kV transmission supply at GMS, it may be possible to maintain the 230 kV connection to SLS under certain wind generation output scenarios. This would allow the wind generation farms to ride through certain momentary outages of the 230 kV transmission supply at GMS.

Further study is required to identify how the new system configuration will be operated in real time. This would include a remedial action scheme design to identify when it would be appropriate to trip generators or shed load under various system conditions.

11.0 Topic: **Effect on wind generation**

Reference: **Exhibit B-1, Appendix B, System Planning Report, Wind generation; Table 1-2: Near Term Wind Generation Projects Table 1-2: Near Term Wind Generation Projects**

1.11.2 To the extent that approval and implementation of the Project builds electrical load in the Dawson Creek/Chetwynd Area is it reasonable to expect that new wind generation resources in the area would be evaluated with a lower or no discount for transmission losses to the Lower Mainland in comparison with other generation resources?

RESPONSE:

No. The building of electrical load in the Dawson Creek/Chetwynd areas would not materially impact the losses to the Lower Mainland of new wind resources in comparison to other generation resources in the area or elsewhere in B.C.

The Lower Mainland/ Vancouver Island (LM/VI) region is BC Hydro's major load centre and it relies significantly on electricity supply from other regions of the province. The Dawson Creek/Chetwynd areas are located within the Peace region which contains a large proportion of BC Hydro's generation capability. This capability exceeds the regional load of the Peace region and is transmitted to the LM/VI region. The load growth in the Dawson Creek/ Chetwynd areas are not expected to materially change the electricity exports out of the Peace region and development of wind or other generation would increase the energy transmitted to the LM/VI region and increase the losses to the Lower Mainland.

11.0 Topic: **Effect on wind generation**

Reference: **Exhibit B-1, Appendix B, System Planning Report, Wind generation; Table 1-2: Near Term Wind Generation Projects Table 1-2: Near Term Wind Generation Projects**

1.11.3 Would approval and implementation of the Project provide any benefit to potential wind generation sources in terms of reduced costs of incremental firm transmission?

RESPONSE:

The Cost of Incremental Firm Transmission (CIFT) is an indication of the long-term unit cost of reinforcements of the bulk transmission system between major areas of generation and load in the province. Approval and implementation of the Project would not have any impact on the CIFT.

12.0 Topic: Project staging

Reference: Exhibit B-1, 3.2.1 Project Staging; 3.2.4 Common F2016 Stage

1.12.1 Please describe the F2016 Stage at a high level, and provide a map showing both the Project and an illustrative configuration of the F2016 Stage.

RESPONSE:

The F2016 stage used for evaluation purposes is further described in Appendix B (page 96 of 100) of Exhibit B-1. It is referred to as "Alternative A: New 230 kV line from GMS to Sundance Substation".

12.0 Topic: Project staging

Reference: Exhibit B-1, 3.2.1 Project Staging; 3.2.4 Common F2016 Stage

1.12.2 Please confirm that BC Hydro would apply for a CPCN for the F2016 Stage. Does BC Hydro have an intended target date for a CPCN application for the F2016 Stage? If so, what is the target date? How much lead time does BC Hydro believe is necessary between a CPCN application and the desired in service date of the F2016 Stage?

RESPONSE:

Please refer to the response to BCUC IR 1.52.1.

13.0 Topic: Impacts on system

Reference: Exhibit B-1

1.13.1 Please discuss and quantify the induced natural gas production electrification load associated with the Project in relation to the BC Hydro integrated system load and load balance.

RESPONSE:

The expected annual gas production and electricity demand are shown in Exhibit B-1, Appendix B, Table 1 on page 82 of 100. This forecast is included in developing BC Hydro's 2010 Electric Forecast before DSM. As such, the gas producer load forecast is reflected in BC Hydro's integrated system load resource balance.

13.0 Topic: **Impacts on system**

Reference: **Exhibit B-1**

1.13.2 By how many months would the need for new generation resources be advanced, or pushed back, if the Project was approved, or the CPCN rejected?

RESPONSE:

BC Hydro is obliged to serve new and existing load whether or not a CPCN is granted for the Project. Thus, the need for new generation resources to be advanced will turn on the decision of customers to electrify, not on whether a CPCN is granted.

14.0 Topic: Environmental project risk

Reference: Exhibit B-1, 7.7 Environmental Impacts of the Project; Appendix F, Environmental Overview Assessment

"Potential effects of the Project include the loss of habitat for fish, vegetation, and wildlife. However, if BMPs are implemented and work windows applied, the majority of Project effects can be reduced or eliminated for all disciplines." [p.192 of 207, pdf p. 538]

1.14.1 Did BC Hydro apply to the B.C. Environmental Assessment Office to voluntarily opt-in to the provincial environmental assessment process under subsection 7(1) of the B.C. Environmental Assessment Act? If not, why not?

RESPONSE:

The Project does not trigger a B.C. Environmental Assessment and BC Hydro did not opt in to the process. In making this decision, BC Hydro considered the following:

1. **BC Hydro did complete an EOA (including studies of wildlife, fish, and socioeconomic issues, among others) which determined there would be minimal Project impact after mitigation measures were implemented;**

2. **The Project is unlikely to trigger CEAA; and**

3. **BC Hydro has been consulting with and commits to continuing to consult with First Nations, key stakeholders and landowners on the Project.**

14.0 Topic: Environmental project risk

Reference: Exhibit B-1, 7.7 Environmental Impacts of the Project; Appendix F, Environmental Overview Assessment

"Potential effects of the Project include the loss of habitat for fish, vegetation, and wildlife. However, if BMPs are implemented and work windows applied, the majority of Project effects can be reduced or eliminated for all disciplines." [p.192 of 207, pdf p. 538]

1.14.2 On what basis will it be determined whether on-site environmental monitors will be engaged by BC Hydro or by contractors? When will that choice be made?

RESPONSE:

The construction contractor will retain the environmental monitors. Please refer to section 5.8 of Exhibit B-1, page 5-24, Lines 20 to 25.

14.0 Topic: Environmental project risk

Reference: Exhibit B-1, 7.7 Environmental Impacts of the Project; Appendix F, Environmental Overview Assessment

"Potential effects of the Project include the loss of habitat for fish, vegetation, and wildlife. However, if BMPs are implemented and work windows applied, the majority of Project effects can be reduced or eliminated for all disciplines." [p.192 of 207, pdf p. 538]

1.14.3 Does BC Hydro retain operational responsibility for auditing and monitoring implementation of the environmental management plan?

RESPONSE:

The contractors' monitors will be responsible for day to day monitoring of the implementation of the EMP/EPPs. BC Hydro's Environmental Officer will audit the contractors and their construction monitors to ensure compliance. Section 5.8 of Exhibit B-1 further describes the responsibility of the contractors' monitors and of BC Hydro's Environmental Officer on the Project.

15.0 Topic: **First Nations project risk**

Reference: **Exhibit B-1, 2.7 Risks and Risk Mitigation; 6. First Nations Consultation and Public Engagement**

1.15.1 To what extent does the Project budget fully incorporate costs associated with BC Hydro meeting obligations or commitments to First Nations? What is the risk of exceeding those cost estimates?

RESPONSE:

Please refer to the response to BCUC IR 1.15.1 and the confidential responses to BCUC IRs 1.2.1 and 1.13.2.

15.0 Topic: **First Nations project risk**

Reference: **Exhibit B-1, 2.7 Risks and Risk Mitigation; 6. First Nations Consultation and Public Engagement**

1.15.2 Does BC Hydro consider that its ability to obtain approval and to complete the Project is at risk due to First Nations issues? If so, what steps and procedures will be followed to address this risk?

RESPONSE:

No. Please refer to the response to BCUC IR 1.15.1.

William E Ireland, QC
Douglas R Johnson+
Allison R Kuchta+
Christopher P Weafer+
Gregory J Tucker+
Terence W Yu+
James H McBeath+
Susan C Blair
George J Roper

D Barry Kirkham, QC+
James D Burns+
Daniel W Burnett+
Paul J Brown+
Karen S Thompson+
Harley J Harris+
Paul A Brackstone+
Edith A Ryan

Robin C Macfarlane+
Duncan J Manson+
Harvey S Delaney+
Patrick J Haberl+
Gary M Yaffe+
Jonathan L Williams+
Scott H Stephens
James W Zaitsoff

J David Dunn+
Alan A Frydenlund+*
James L Carpick+
Michael P Vaughan
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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

INTERLAW MEMBER OF INTERLAW, AN INTERNATIONAL ASSOCIATION OF INDEPENDENT LAW FIRMS IN MAJOR WORLD CENTRES

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

The only local source of generation in the Dawson Creek area is the 102 MW Bear Mountain Wind Farm located approximately 15 km south west from the City of Dawson Creek, which provides an intermittent source of electricity to the area. The 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.

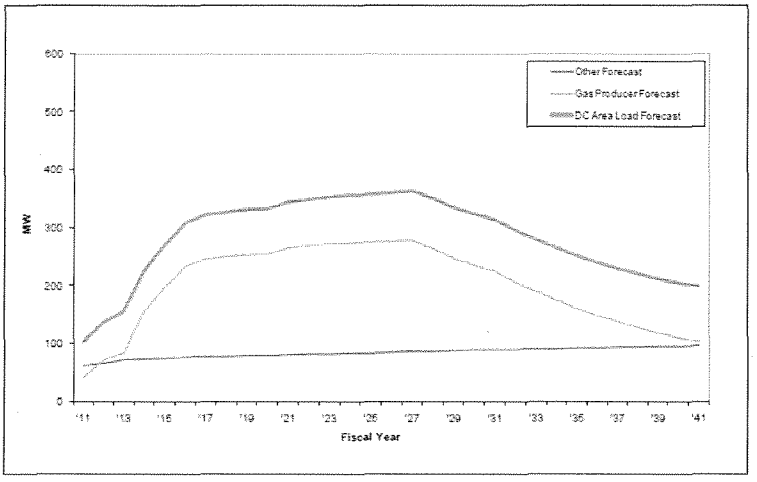
3.5 Please describe the limits, if any, of the GMS facility to integrate additional wind farm generation from the Peace River area.

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.

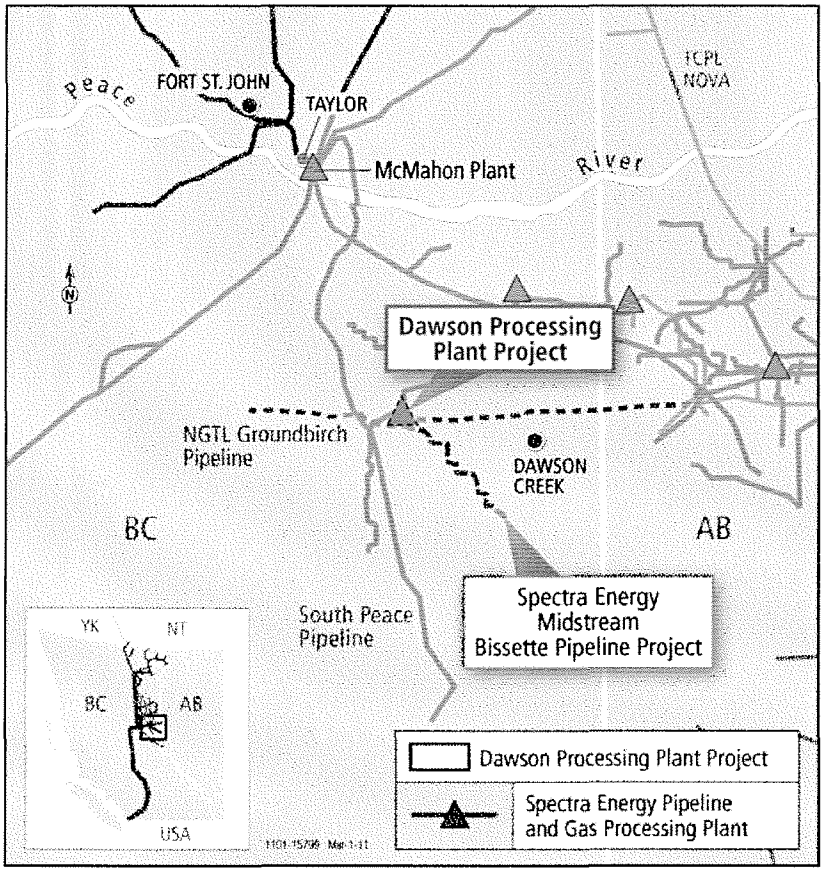
4.4 Please describe why BC Hydro the BC Hydro area transmission planning does not expect that it is possible to service load from the SNK substation yet in a second stage for serving maximum loads options include 230KV transmission from SNK.

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



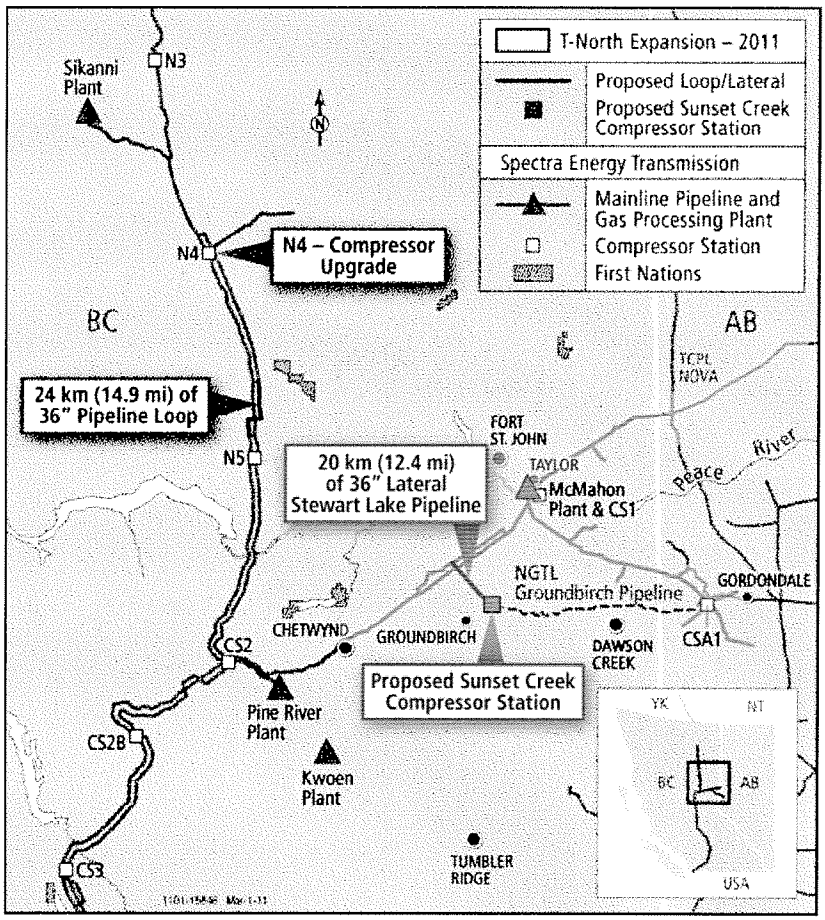
- Location: Dawson Creek area, northeast British Columbia
- Approximate Size of Proposed Facility: 60 acres
- Processing Capacity:
  - Phase 1: 100 million cubic feet per day (MMcf/d)
  - Phase 2: 100 million cubic feet per day (MMcf/d)
- Source of Gas Supply: Montney shale gas formation/South Peace 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

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

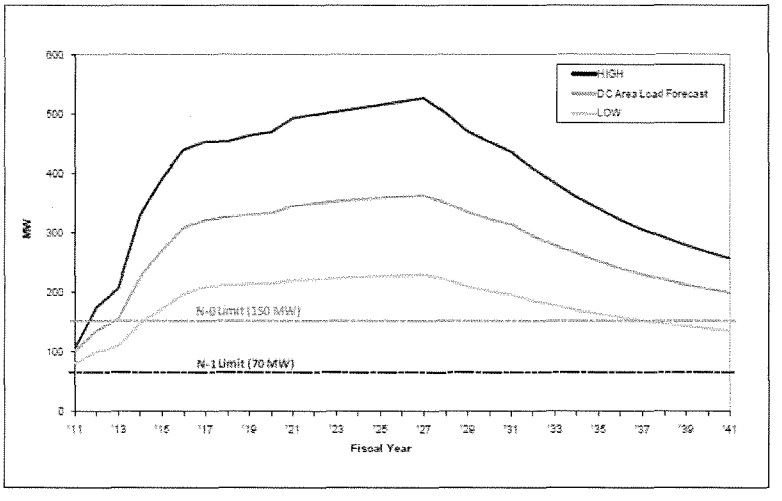
11 Starting in F2014 during winter conditions with all system elements in service the
12 system will experience: 1) low 138 kV voltages at BMT resulting in transmission
13 voltage customer Electric Service Agreements (**ESAs**) not being met: and 2) low
14 voltages for the DAW 25 kV system. Overcoming 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

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

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

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

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

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

> The addition of a new 230 kV double circuit transmission line, together with the new SLS and corresponding upgrades at BMT and DAW, will increase the firm 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

> The addition of a single new 138 kV transmission line constructed on double circuit structures, together with the new SLS and corresponding upgrades at BMT and DAW will increase the firm transmission capacity that serves the Dawson Creek area 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

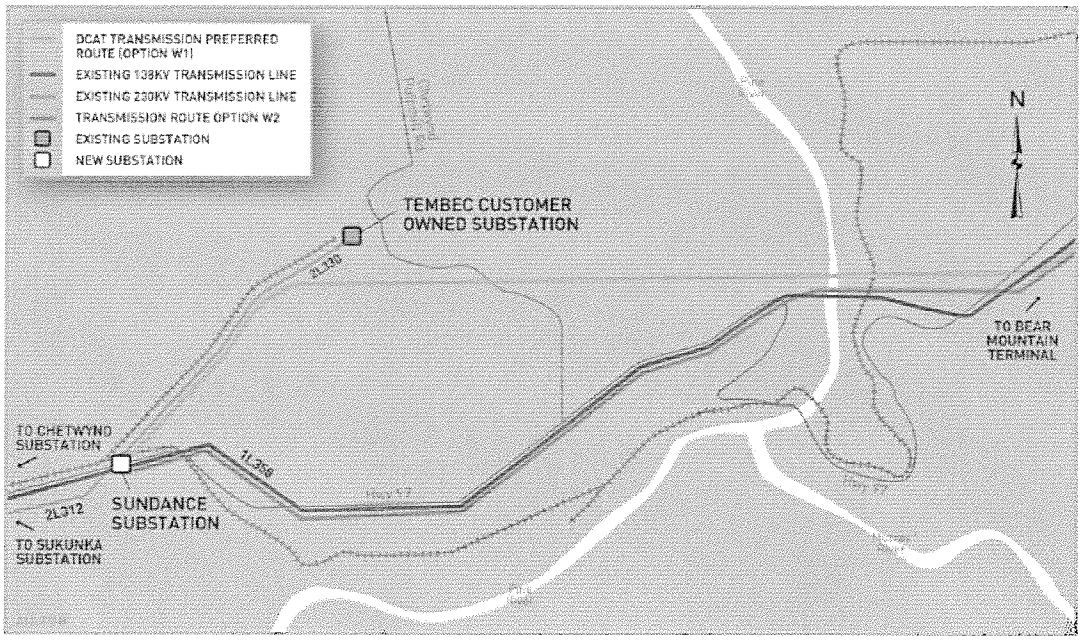
Transmission line ROWs must be cleared to prevent flashovers and possible safety issues due to growing/falling vegetation. All trees within the ROW will be cleared, which is estimated to be approximately 130 hectares (320 acres, 1,297,707 m^2).

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

> ***6.1.6.1 Summary of Consultation to Date***
>
> A high level summary of BC Hydro's consultation process to date is provided below. Supporting documentation related to the consultation communications between 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

> The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is 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?

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.

1.1.1 Please identify what loads are not served at the peak for F2011.

RESPONSE:

All loads were served in the Dawson Creek area at the peak for F2011 because no transmission line outages were experienced during F2011 winter peak conditions.

The firm transmission capacity in F2011 was approximately 50 MW (Exhibit B-1, Appendix B, pages 14 and 15 of 100).

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.

1.1.2 Please quantify the loads are not served at the peak for F2011.

RESPONSE:

Please refer to the response to CEC IR 1.1.1

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.

1.1.3 Please quantify for how long the loads cannot be served at the peak for F2011.

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.

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.

1.1.4 Please quantify at what times the loads cannot be served at the peak for F2011.

RESPONSE:

Please refer to the response to CEC IR 1.1.1.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.1.5** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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.

1.1.5 Please quantify the amount of energy not provided at the peak for F2011.

RESPONSE:

Please refer to the response to CEC IR 1.1.1.

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.

1.1.6 Please identify and quantify the same information as above as estimates for F2012, F2013 and F2014.

RESPONSE:

The following table shows estimates of the quantity of load in the Dawson Creek area, prior to the implementation of the DCAT Project, which exceeds the firm transmission limits, unavailability, and expected energy not served for F2012, F2013, and F2014. This analysis was based on the 70 MW voltage stability limit on the outage of 1L377 which represents the most severe transmission line contingency.

	F2012	F2013	F2014
Load above Capacity (MW)	Up to 64	Up to 82	Up to 114
Unavailability (%)	0.094	0.094	0.094
Expected Energy Not Served (MWh)	80,100	92,850	113,000

The following table show estimates of the quantity of load in the Dawson Creek area which exceeds system normal (N-0) transmission limits, duration above capacity, and expected energy not served for F2012, F2013, and F2014.

	F2012	F2013	F2014
Load above Capacity (MW)	0	0	34
Duration Above Capacity (Hours)	0	0	3,233
Expected Energy Not Served (MWh)	0	0	516,140

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.

1.1.7 Please describe the load shedding regime and rules in place for F2011.

RESPONSE:

Regime:

A Local Area Protection Scheme (LAPS) was implemented in November 2010 to provide automatic under-voltage load shedding in the Dawson Creek – Chetwynd areas. The scheme, an interim mitigation plan, was used to provide system security against possible area wide voltage collapse or blackout due to an N-1 outage during winter heavy load period of either 1L361 GMS-Chetwynd lines or 1L377 Taylor-Dawson Creek line.

The load shedding by LAPS was applied at three stations: DAW, BMT, and CWD. The scheme was based on local intelligence at the three stations:

- **The load shedding at DAW is triggered by opening of the 1L377 line breaker with accompanying pre-set under-voltage, or if the under-voltage persists by pre-set delayed under-voltage;**
- **The load shedding at CWD is triggered by opening of the 1L361 line breaker with accompanying pre-set under-voltage, or if the under-voltage persists by pre-set delayed under-voltage; and**
- **The load shedding at BMT trips 1L355 line by only pre-set delayed under-voltage. This was implemented as a back-up to the under-voltage load shedding protection applied by the customer at their three nodes (plants).**

The loads would be restored manually by System Operations when the lines are restored to service.

Rules:

At DAW substation up to four of the eight distribution feeders could be tripped by the LAPS scheme. The number of feeders armed for tripping was dependent on the forecast shortfall in transmission supply capacity to the Dawson Creek - Chetwynd area. The feeders to be tripped were pre-selected and prioritized based on percentage of interruptible industrial load connected to the respective feeders. The general intention was to restore supply to the residential and commercial customers by restoring the tripped feeders while remotely operated distribution reclosers would be used to disconnect the industrial loads from those feeders until the system outage was restored.

At CWD substation up to two of the three distribution feeders could be tripped by the LAPS scheme. The number of feeders armed for tripping was dependent on the forecast shortfall in transmission supply capacity to the Dawson Creek - Chetwynd area. The feeder serving the hospital and critical loads are excluded from the LAPS load shedding. The general intention was to restore supply to all customers by restoring the tripped feeders when the transmission system is restored to service.

At BMT the line 1L355 would be restored once the area system is restored to normal service.

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.

1.1.8 Please describe the load shedding regime and rules planned for F2012, F2013 and F2014.

RESPONSE:

Regime:

The required Local Area Protection Scheme (LAPS) would provide automatic under-voltage load shedding in the Dawson Creek - Chetwynd Area and would incorporate local and remote intelligence through new telecom facilities. It would include more redundancy for greater reliability, and will be also designed to provide selective load shedding to reduce instances of over-shedding. The LAPS would accommodate the redevelopment of DAW including the following additions:

- **Reconfiguration of the 138 kV bus and circuit breaker arrangement;**
- **138 kV switchable shunt capacitors;**
- **Replacement of existing switchable 25 kV shunt capacitor with two smaller sized units;**
- **Addition of a third 138 kV/25 kV transformer; and**
- **Additional two distribution feeders for a total of ten feeders.**

The load shedding would be applied at two stations: DAW and CWD. This LAPS would provide fast load shedding at the two stations as follows:

- **The load shedding at DAW would be triggered by faults on either 1L361 or 1L377 that result in tripping the respective line. During an outage event, the amount of load shedding would be based on the pre-trip total power transfer level on 1L361 and 1L377, south of GMS and Taylor respectively.**

- **The load shedding at CWD would be triggered by a fault on 1L361 that results in the tripping of the line. The amount of load shedding would be based on the pre-trip total power transfer level on 1L361 and 1L377, south of GMS and Taylor respectively.**

The loads are to be restored manually or by supervisory controls by System Operations when the lines are restored to service.

Rules:

At DAW up to six of the ten distribution feeders would be tripped by the LAPS scheme. The number of feeders armed for tripping would be dependent on the forecast shortfall in transmission supply capacity to the Dawson Creek - Chetwynd area. The feeders to be tripped would be pre-selected and prioritized based on percentage of interruptible industrial load connected to the respective feeders. The general intention is to restore supply to the residential and commercial customers by restoring the tripped feeders while remotely operated distribution reclosers would be used to disconnect the industrial loads from those feeders until the system outage is restored.

At CWD up to two of the three distribution feeders would be tripped by the LAPS scheme. The number of feeders armed for tripping would be dependent on the forecast shortfall in transmission supply capacity to the Dawson Creek - Chetwynd area. The feeder serving the hospital and critical loads will be excluded from the LAPS load shedding. The general intention is to restore supply to all customers by restoring the tripped feeders when the system is restored.

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.

1.1.9 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.

RESPONSE:

The industrial load customers to be connected to the Dawson Creek area system have been informed that they would be connected as interruptible loads until such time that the single contingency (N-1) capacity of the transmission system supplying the area is adequate. Some industrial load customers connected in the 2011 time frame or earlier are participating in the load shedding scheme.

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.

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.

1.1.10 Please provide a breakdown of the load by customer type for F2011, F2012, F2013 and F2014.

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**

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.

1.1.11 Please provide annual and peak daily load profiles for each of the customer types identified above.

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.

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.

1.1.12 Why has BC Hydro not provided peaking support in the area to date?

RESPONSE:

BC Hydro's current mitigation plans are sufficient in the near term for meeting the systems needs until the implementation of the DCAT Project.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.1.13** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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.

1.1.13 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?

RESPONSE:

Near term reinforcements are described in Exhibit B-1, Appendix B, page 14 of 100. These include the 138 kV Shunt Capacitor Banks, and a third 138/25 kV transformer at DAW.

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.

1.1.14 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.

RESPONSE:

Confirmed.

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.

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

RESPONSE:

Confirmed. The shunt capacitor and the transformer additions at the Dawson Creek Substation (DAW) are described in Appendix B of Exhibit B-1 on page 14 of 100 under the heading "Near Term System Reinforcements." The "Near Term System Reinforcements" are not part of the DCAT 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.

1.1.16 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.

RESPONSE:

The shunt capacitors and transformer upgrades are being implemented to serve loads identified and committed in the 2009/2010 timeframes. These projects were not justified on the basis of increasing the reliability for existing customers who have load shedding regimes in place.

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.

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

RESPONSE:

BC Hydro has no plans to provide peaking support for F2013 and F2014. BC Hydro considers existing mitigation plans to be sufficient in meeting system needs prior to and after the implementation of the DCAT Project.

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.

1.2.1 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.

RESPONSE:

Assuming the Dawson Creek area load is set to F2011 winter load levels, the following transfer capabilities would exist at CWD when all transmission lines are in service (N-0) and when CWD is only served by 1L361 (N-1):

- **N-0: 130 MW; and**
- **N-1: 100 MW.**

These limits were based on maintaining acceptable operating voltages.

Note that as the Dawson Creek area load increases, the N-0 limit to CWD would decrease since both these areas are served by a common 138 kV transmission system.

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.

1.2.2 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.

RESPONSE:

The transfer capability of a transmission system is not solely based on the linear addition of individual line thermal capacities since transmission capacity can also be constrained by voltage. Voltage at a particular system bus is impacted by many factors including load characteristics and location, power transfer levels, characteristics of reactive compensation devices, system impedance, and generator characteristics.

For example, if a station is being supplied by two lines with the same electrical parameters and thermal ratings but of different lengths, this could result in the ability of each line supplying the station on its own to be different due to voltage constraints, if voltage limits are encountered before thermal limits. BC Hydro would define the N-1 transfer capability by the most constraining outage.

In the case where voltage limits exists, it may be possible to add reactive compensation devices which provide the function of supporting system voltages thereby increasing transfer capability. Installing sufficient reactive compensation may result in system firm capacity to then be defined by a transmission line's thermal limits. In this case, new transmission lines or generation would need to be installed to further increase transmission capacity.

Through application of system simulation which includes modeling of the electrical characteristics of system components and loads, it was determined that the constraining outage in supplying the Dawson Creek area is the loss of 1L377 with a limit of 70 MW, and with all system elements in service the system limit was found to be 150 MW. Both of these limits are defined by voltage limit violations.

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.

1.2.3 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?

RESPONSE:

BC Hydro does not consider this a feasible alternative. The existing structures cannot accommodate an additional conductor due to the structural load resulting from the additional conductor. An additional conductor will also require new insulators and hardware including spacer dampers for the entire line length. Adding an additional conductor would require all new structures and effectively require a complete rebuild of the line.

Although energized work methods exist to do this work, significant outages would be required to perform this upgrade, which would compromise the already strained system in the area.

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.

1.2.4 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.

RESPONSE:

The thermal capacity of existing lines is not adequate to meet the forecast load as early as F2012. Therefore, power transfer could only be effectively improved through implementation of additional transmission lines or local generation.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.3.1** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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

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

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

RESPONSE:

Confirmed.

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

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

1.3.2 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.

RESPONSE:

Please refer to the responses to CEC IRs 1.9.1 and 1.10.5.

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

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

1.3.3 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.

RESPONSE:

BC Hydro cannot provide the information requested, as it pertains to third-party confidential information and the third-party has not agreed to its release.

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

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

1.3.4 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.

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.

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

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

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

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.

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

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

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

RESPONSE:

Please refer to the response to CEC IR 1.3.5.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.3.7** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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

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

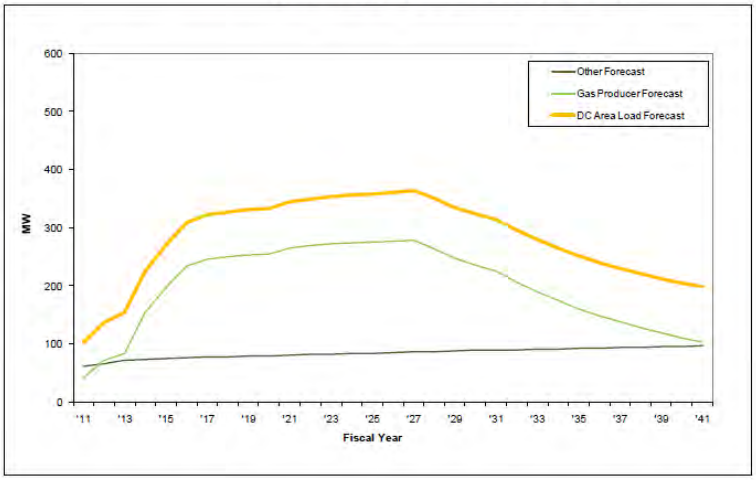
1.3.7 Please identify whether or not BC Hydro has identified back-up generation capability of customers in the area and if so please quantify the amount.

RESPONSE:

Yes, one customer has back-up generation of 8 MW.

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

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



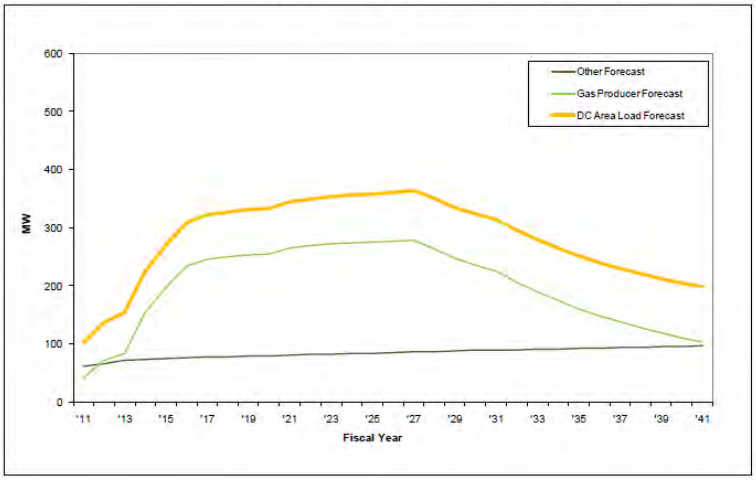
1.4.1 Please provide a specific point mapping of where the loads are anticipated to be within the Dawson Creek and Groundbirch areas.

RESPONSE:

A specific point mapping is not possible because of the confidential nature of customer plans and locations, and some of the locations haven't been determined at this time.

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

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



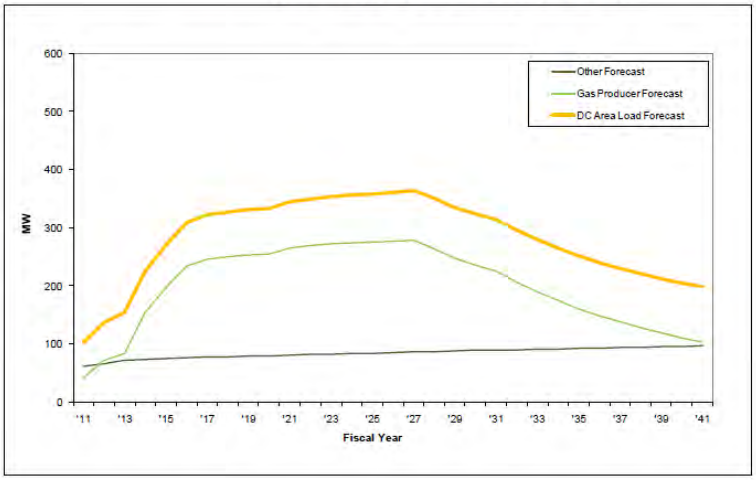
1.4.2 To the extent a specific point mapping is not possible, with the current level of customer requests and intents currently being studied, please provide a breakdown between the Dawson Creek area and the Groundbirch area.

RESPONSE:

The breakdown between Groundbirch and Dawson Creek areas for prospective large customers is approximately 45 and 55 per cent, respectively.

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

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



1.4.3 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.

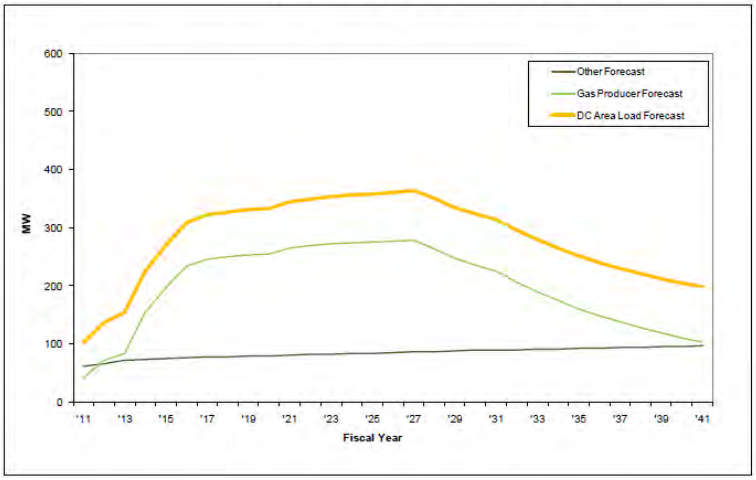
RESPONSE:

The forecast load in the Groundbirch area could be supplied by SNK. After the implementation of the DCAT Project, the 230 kV system at Groundbirch would be served by 2L312 which is connected to SNK.

Alternately, a new 230kV line could be constructed in parallel with 2L312 from SNK to the new Groundbirch load. The 30-year transmission plan to supply the Groundbirch and Dawson Creek area loads also considers a second 230 kV line in this area.

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

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



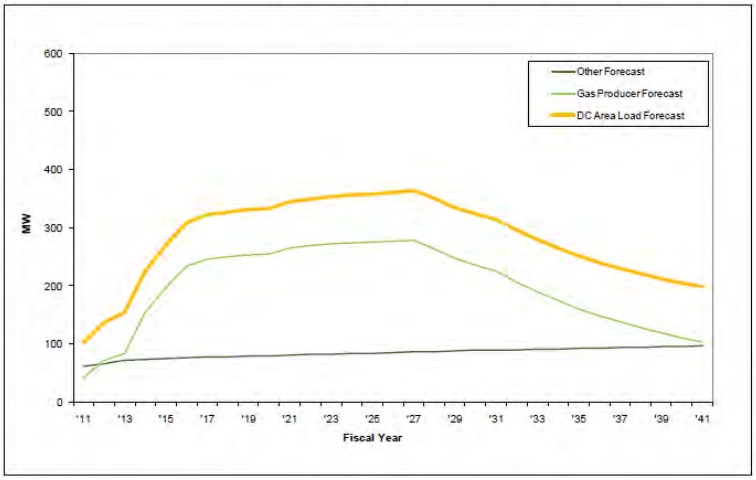
1.4.4 Please describe why BC Hydro the BC Hydro area transmission planning does not expect that it is possible to service load from the SNK substation yet in a second stage for serving maximum loads options include 230KV transmission from SNK.

RESPONSE:

BC Hydro does not understand the premise of the question, as no such expectation is expressed in the System Planning report, included at Exhibit B-1, Appendix B. Please refer to the response to CEC IR 1.4.3.

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

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



1.4.5 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.

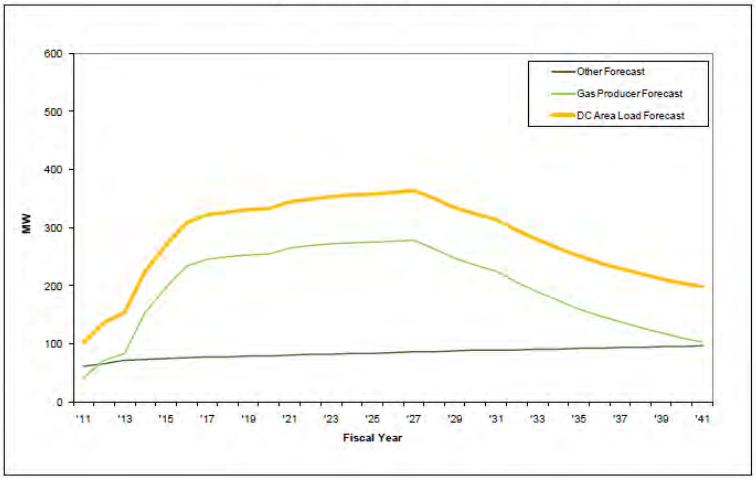
RESPONSE:

Other parts of the 230 kV system are not as suitable as the new Sundance Substation (SLS) connected to 2L312 to supply the Groundbirch and Dawson Creek area loads, due to the anticipated location of these expected loads.

Please also refer to the response to CEC IR 1.40.2.

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

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



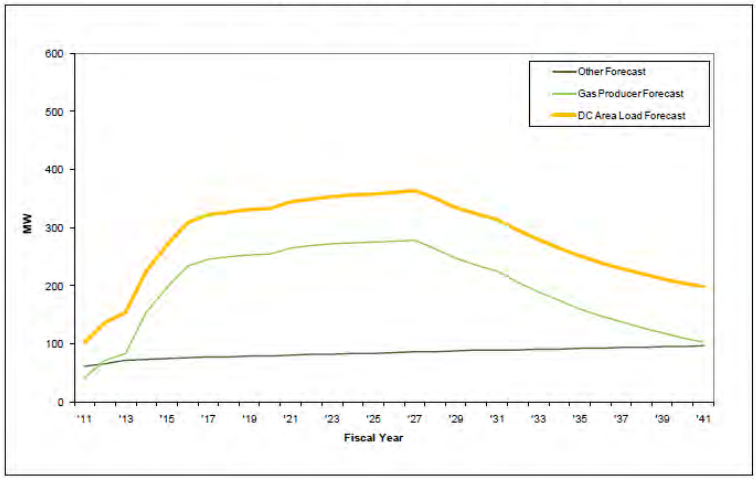
1.4.6 Please identify the potential magnitude of gas producer loads per compression unit.

RESPONSE:

BC Hydro's Load Forecast does not depend upon the potential magnitude of gas producer loads per unit. Different producers may have different levels of horse power per compressor so the potential magnitude varies within the industry and the equipment to be installed. BC Hydro's load forecast is based on an electricity intensity range from 0.11 to 0.12 MW/MMcf/day.

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

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



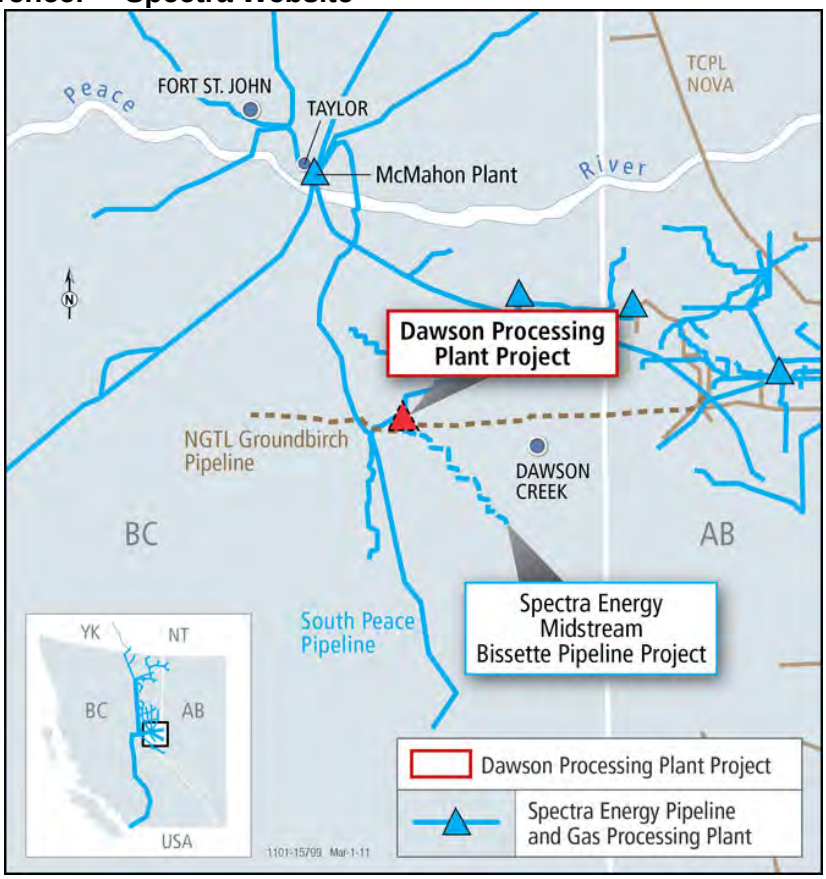
1.4.7 Please identify what would be required to service gas producer loads from the 230 KV transmission system, presumably 230KV transformers stepping down to 138 KV transmission voltage for transmission customers and to distribution levels for distribution customers.

RESPONSE:

Servicing the gas producer loads from the 230 kV transmission system could include the following:

1. **Tap to an existing 230 kV line;**
2. **Connection to an existing or new 230 kV switching station;**
3. **Step down transformation to 138 kV for 138 kV transmission interconnection; and**
4. **Step down transformation to 25 kV for distribution interconnection.**

5.0 Reference: Spectra Website



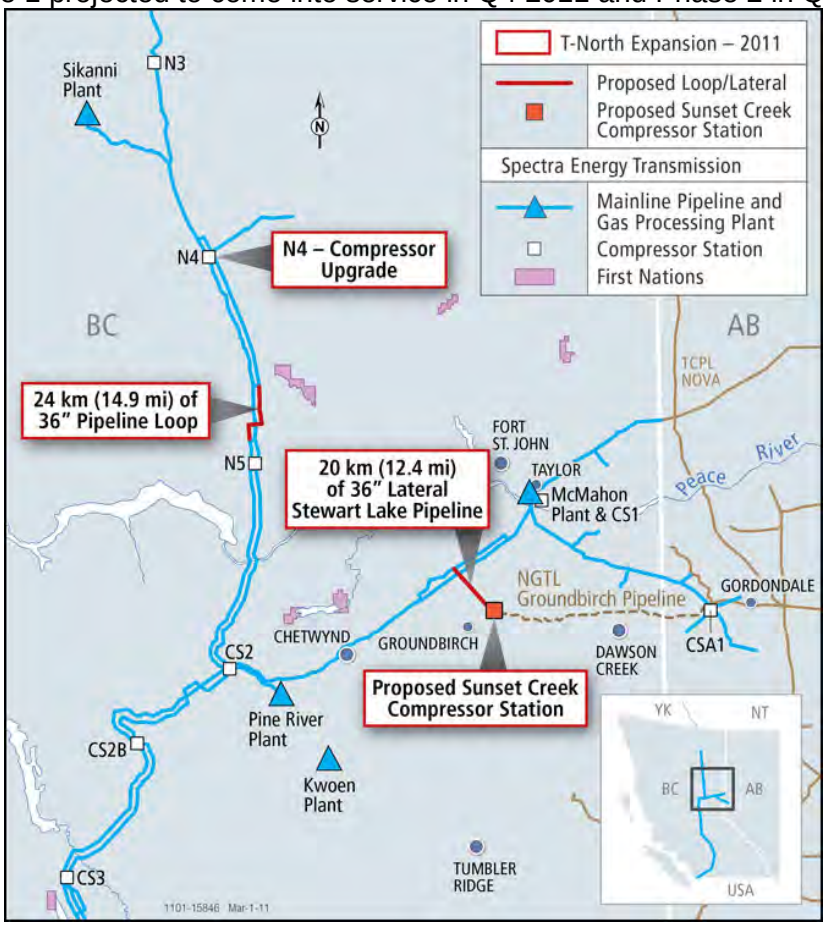
- Location: Dawson Creek area, northeast British Columbia
- Approximate Size of Proposed Facility: 60 acres
- Processing Capacity:
  - Phase 1: 100 million cubic feet per day (MMcf/d)
  - Phase 2: 100 million cubic feet per day (MMcf/d)
- Source of Gas Supply: Montney shale gas formation/South Peace 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.

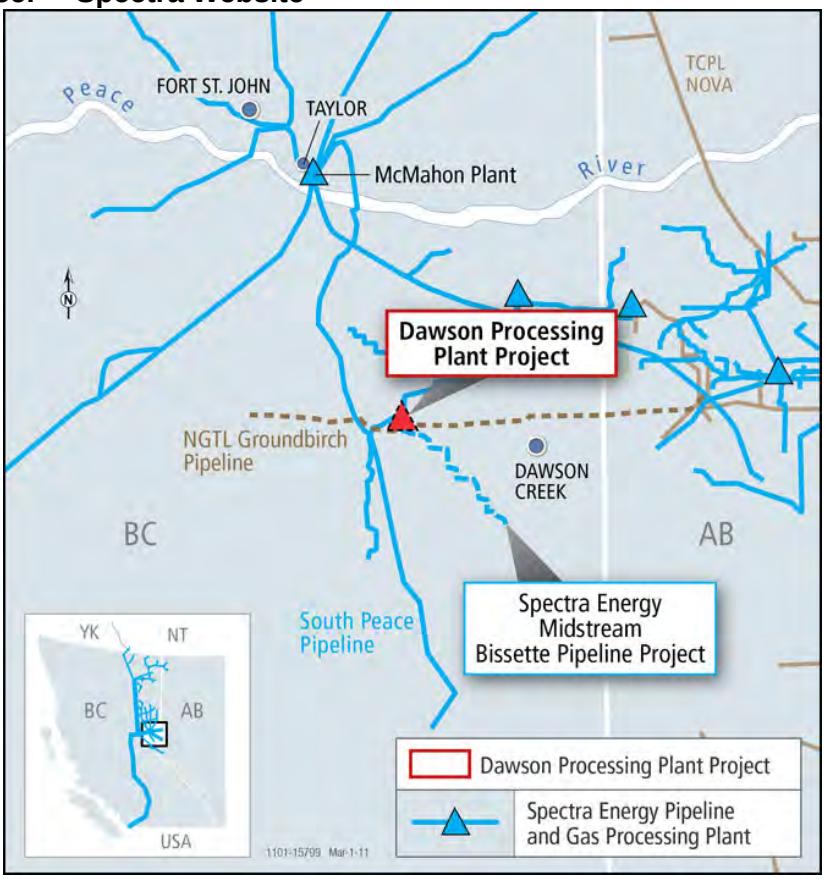
Spectra Energy's pipeline system is well positioned for future growth based on customer need and timing. A second binding pipeline open season in 2010 resulted in a further 550 MMcf/d committed under long term demand-based arrangements supporting a further expansion of the T-North system in the 2012/2013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

1.5.1 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.

RESPONSE:

Customer specific load information is confidential and therefore has not been provided.

5.0 Reference: Spectra Website



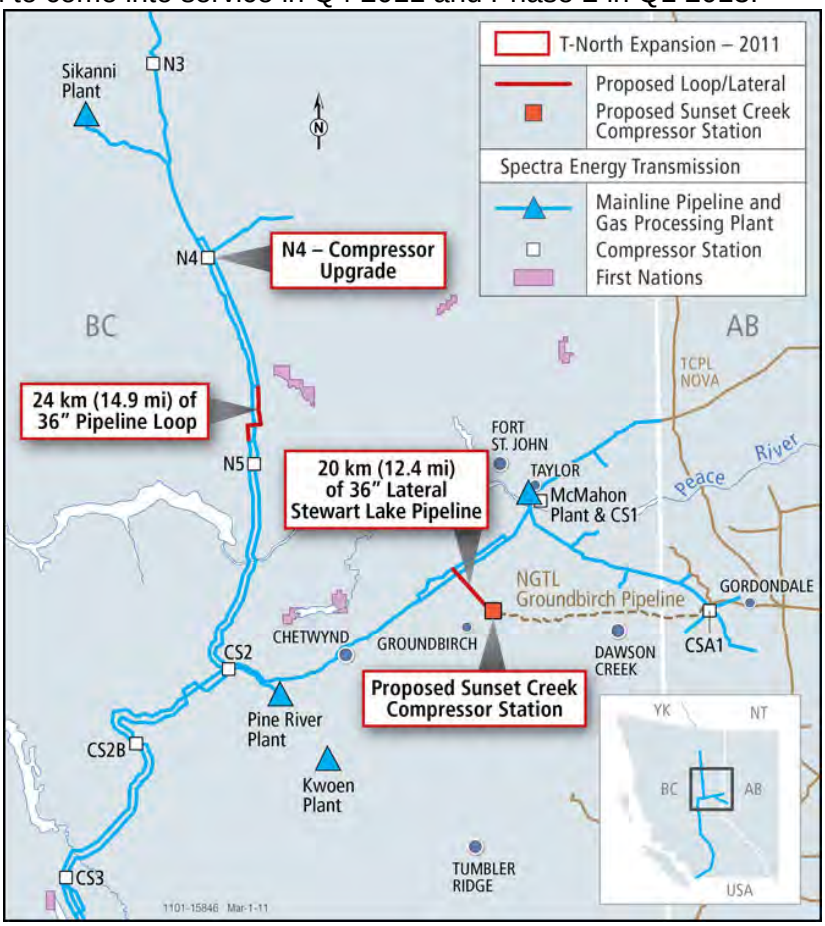
- Location: Dawson Creek area, northeast British Columbia
- Approximate Size of Proposed Facility: 60 acres
- Processing Capacity:
  - Phase 1: 100 million cubic feet per day (MMcf/d)
  - Phase 2: 100 million cubic feet per day (MMcf/d)
- Source of Gas Supply: Montney shale gas formation/South Peace 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
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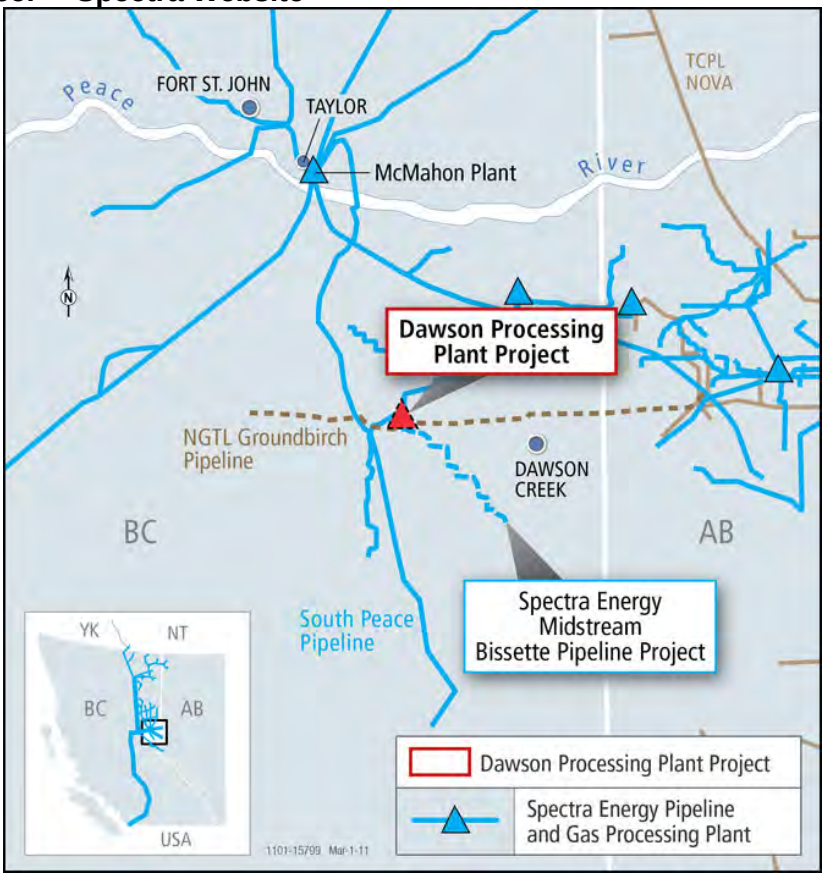
1.5.2 Please indicate whether these loads would be served from DAW, BMT or SLS.

RESPONSE:

Please refer to the response to CEC IR 1.5.1.

5.0 Reference: Spectra Website



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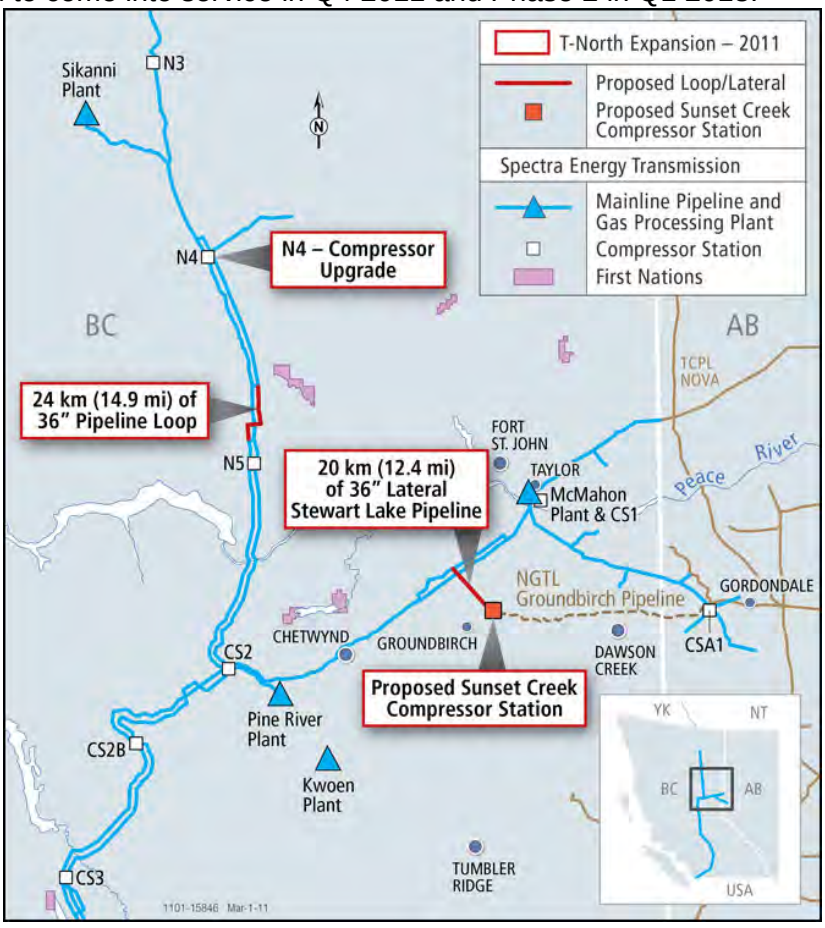

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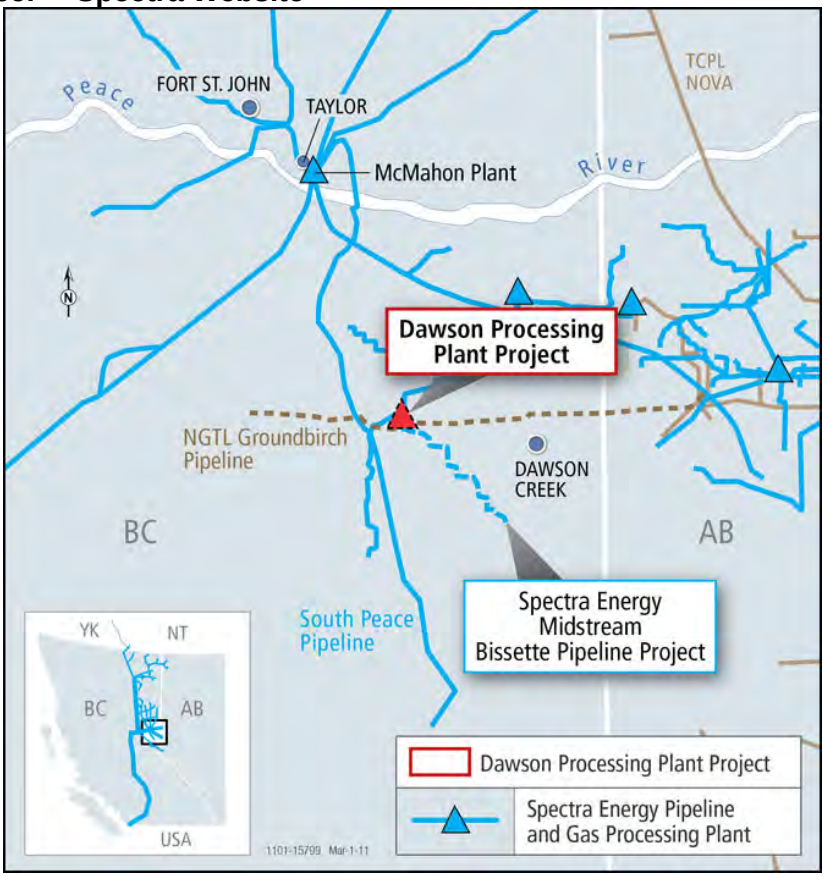
1.5.3 Given the location of a gas processing plant in the Groundbirch area and connections to the South Peace Pipeline and to the CS2 to Taylor area CS1 and McMahon plant, it would appear that this would be a focal point for a considerable amount of the potential load, is this correct.

RESPONSE:

BC Hydro's anticipated potential loads are distributed throughout Groundbirch and Dawson Creek areas.

5.0 Reference: Spectra Website



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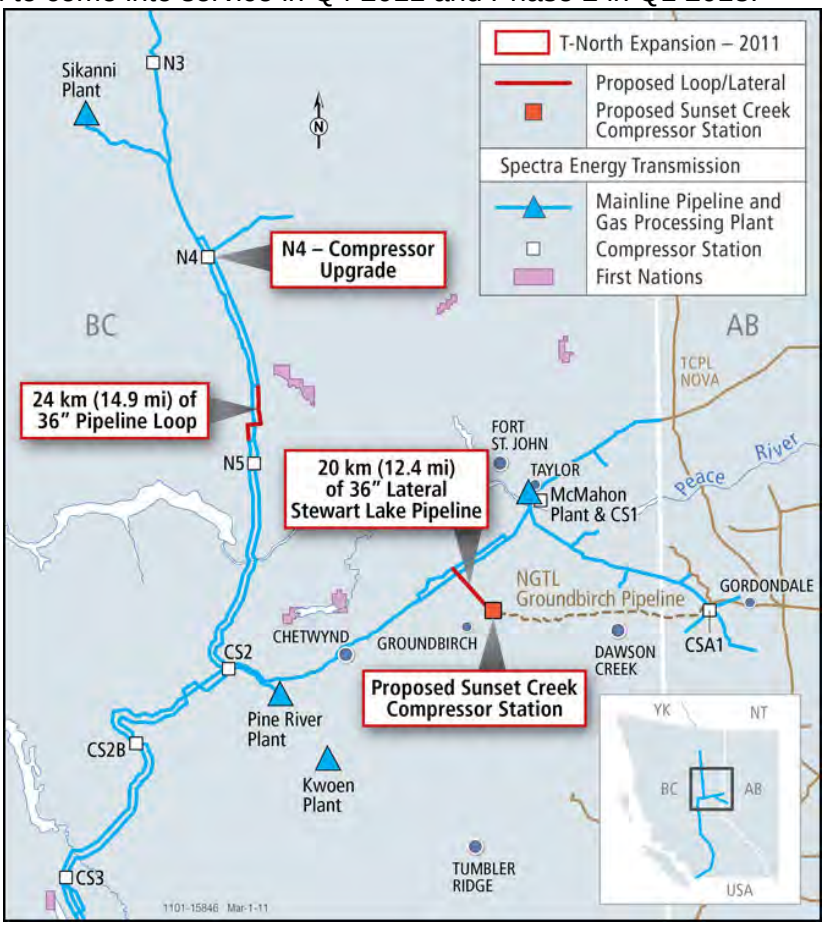

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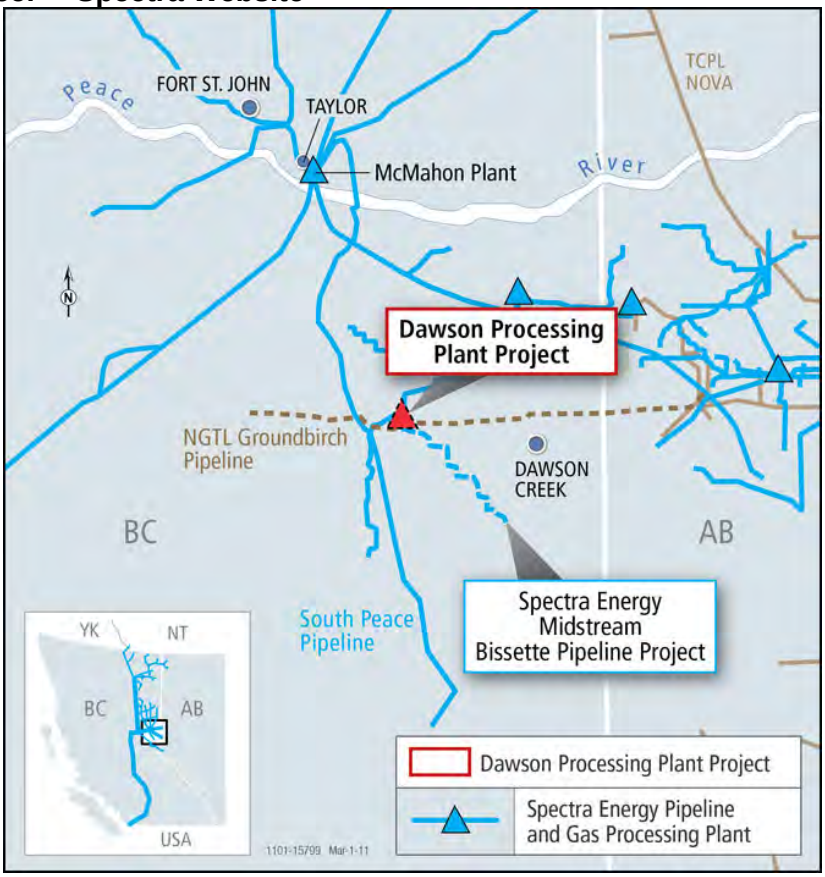
1.5.4 Given the potential load in this area, is there a possibility in the development of load such that a significant portion of the load may not need to be serviced from DAW and therefore the transfer capability upgrade all the way to DAW may not be a necessary as the planning shown in the CPCN may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

RESPONSE:

BC Hydro's Application addresses the forecasted load in both the Groundbirch and Dawson Creek areas.

5.0 Reference: Spectra Website



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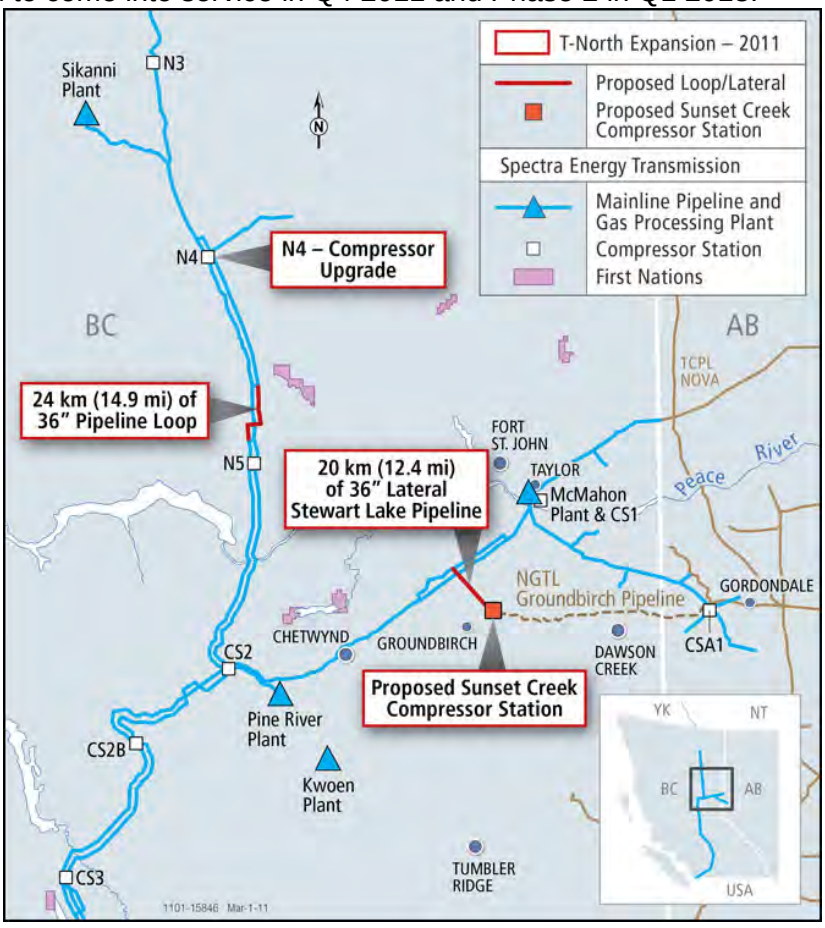

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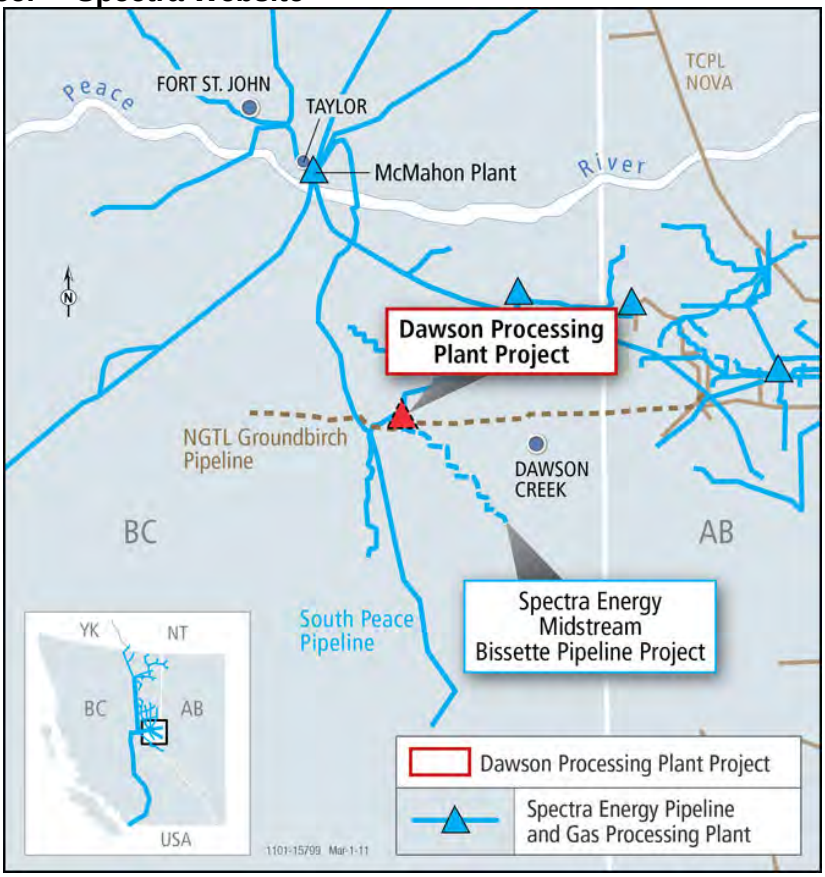
1.5.5 What if any examination of the potential detailed interconnections and loads has BC Hydro used to develop the transmission systems planning or has it been essentially the area load forecast assumed to be focused on DAW that has driven the planning?

RESPONSE:

The interconnection of individual load customers was considered during the system planning process.

5.0 Reference: Spectra Website



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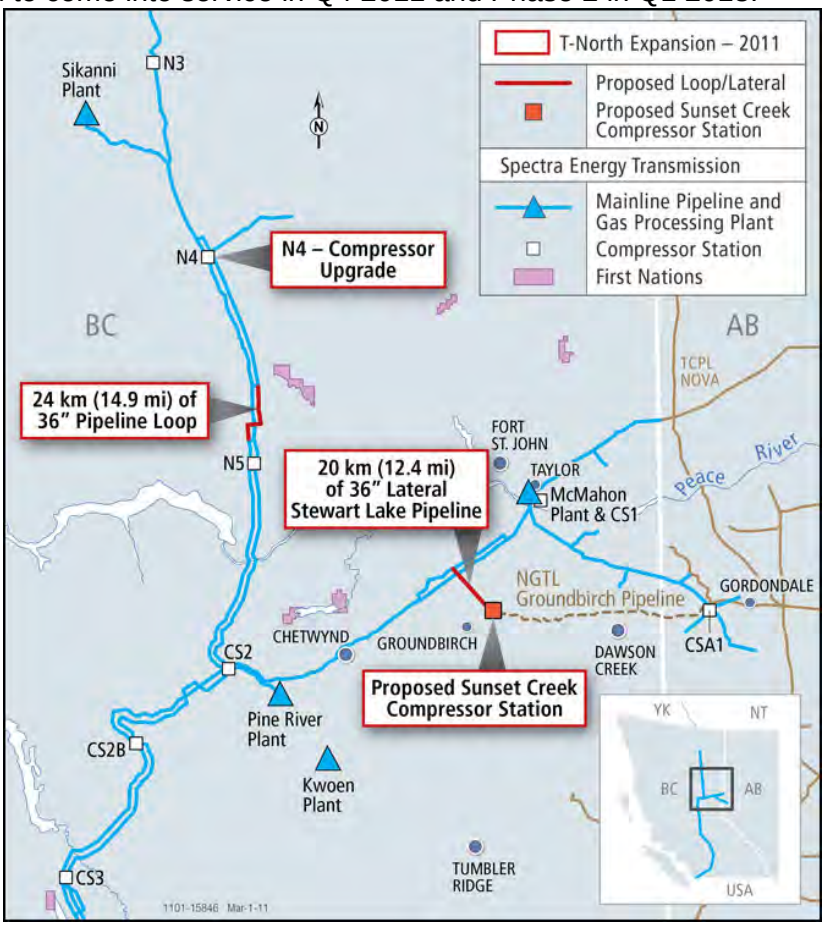

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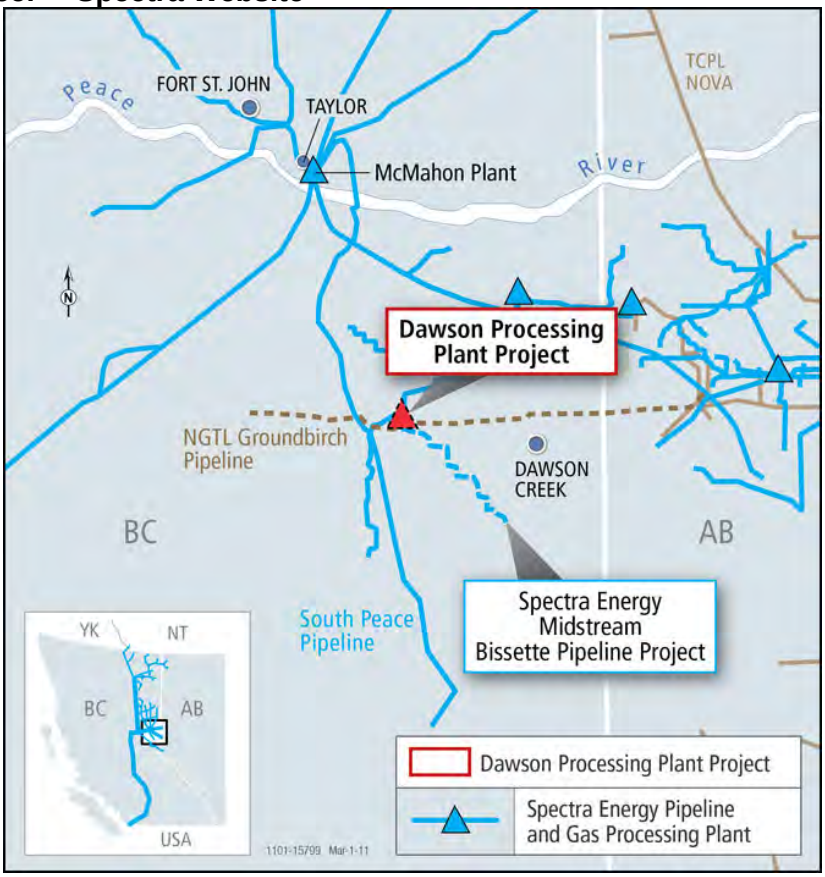
1.5.6 What other specific planned loads is BC Hydro aware of? Please provide all details known.

RESPONSE:

BC Hydro is working with Spectra Energy and other potential customers, but is unable to discuss their specific plans. BC Hydro treats these plans as confidential until made public by the customer.

BC Hydro provided confidential information with respect to customer loads in its response to BCUC IR 1.44.1, filed on a confidential basis.

5.0 Reference: Spectra Website



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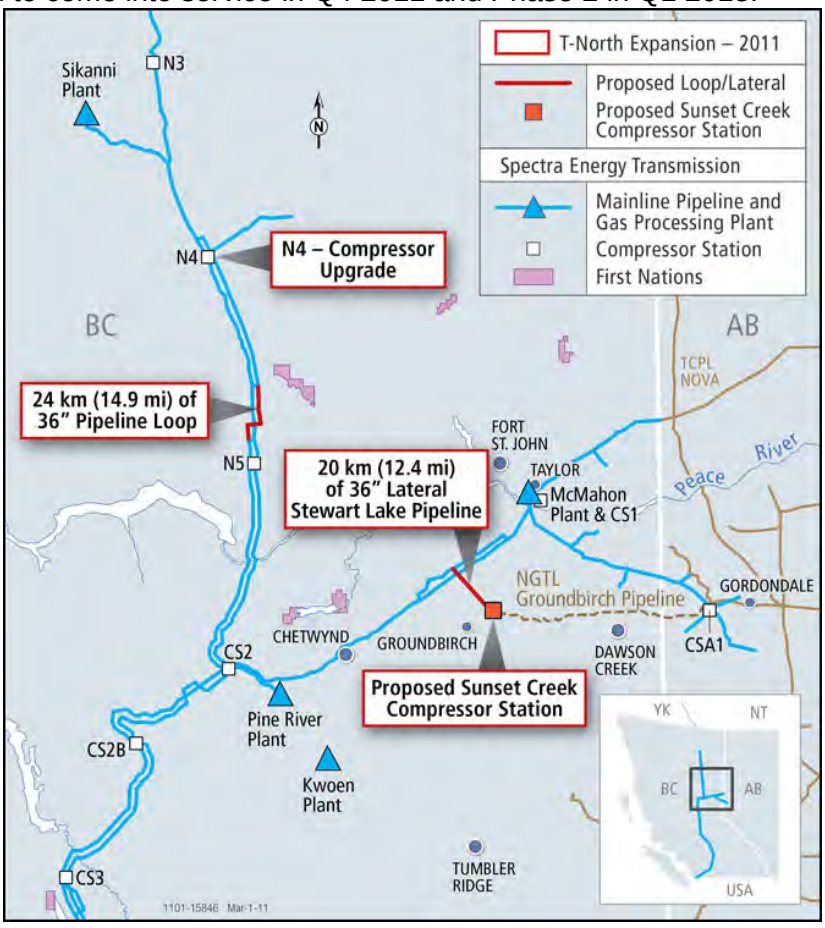

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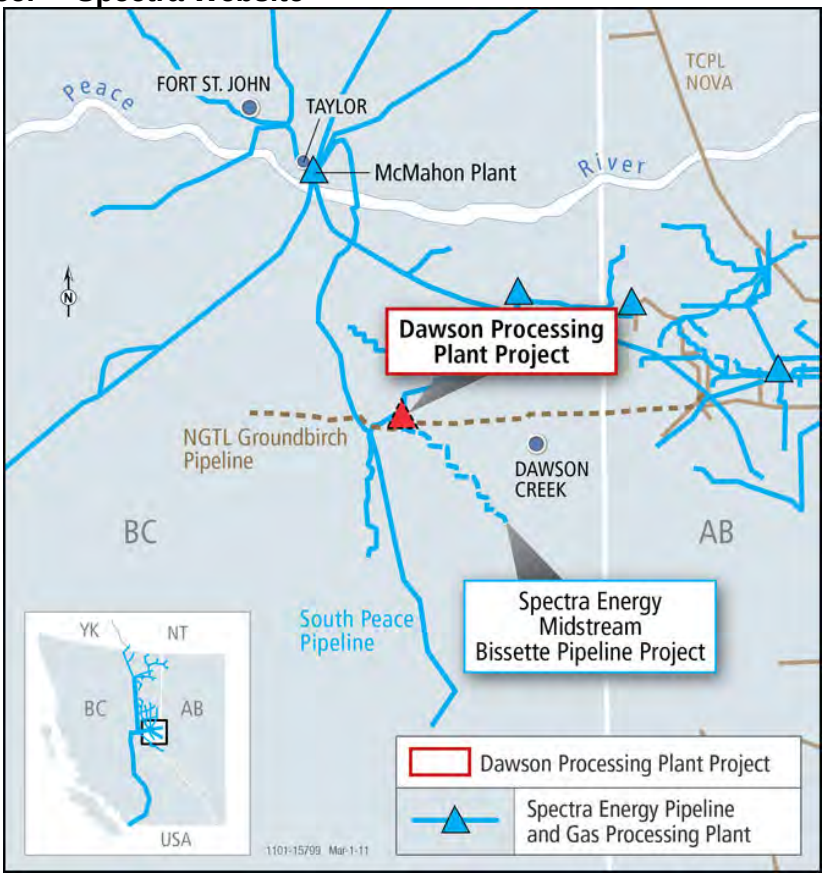
1.5.7 Has BC Hydro investigated the potential for co-generation opportunities next to the planned Dawson processing plant, as is the case in Taylor?

RESPONSE:

BC Hydro, as proponent, has not investigated the potential for co-generation opportunities next to the Dawson processing plant as an alternative to the DCAT Project. BC Hydro is also not aware of any IPP co-generation development interest next to the Dawson processing plant.

5.0 Reference: Spectra Website



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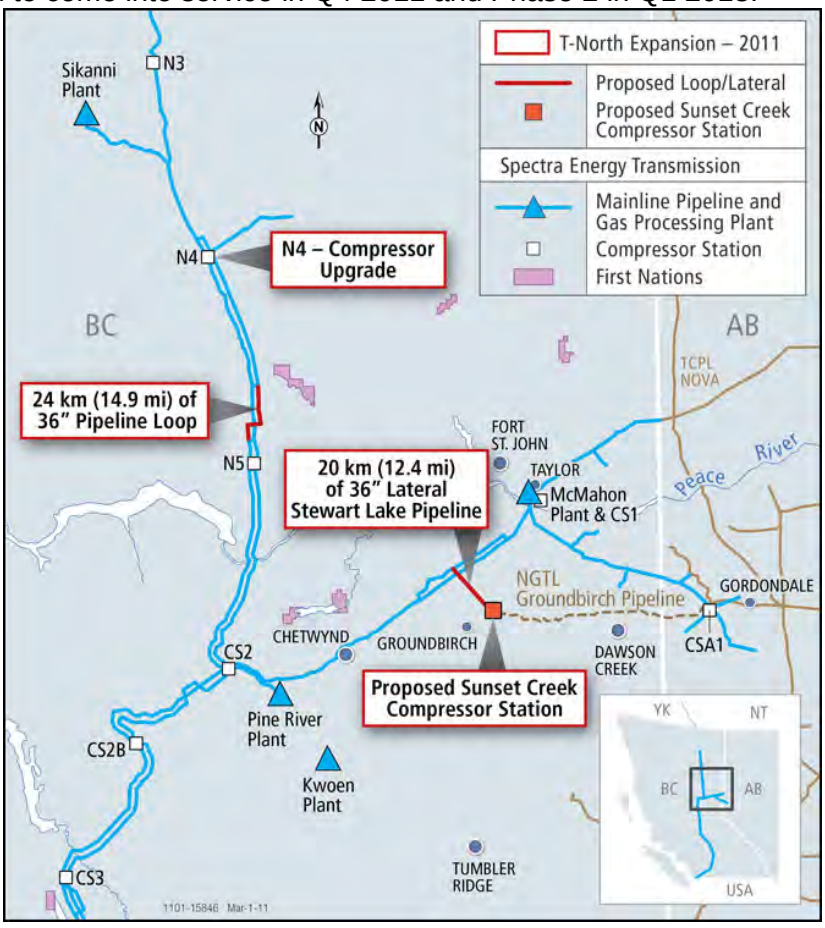

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1.5.8 How could such a cogeneration opportunity help and assist the electrical supply stability, thermal limitations and future load service in the area?

RESPONSE:

Please refer to the response to CEC IR 1.5.7.

Note that the Spectra Energy owned McMahon Cogeneration Plant (MCM) was included in system modeling data when undertaking the system planning study. MCM's dependable generation capacity is reflected in the system performance analysis as detailed in the system planning report included with the Application (Exhibit B-1, Appendix B).

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

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

1.6.1 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.

RESPONSE:

Both natural gas fuelled compressors and electric driven compressors are providing the same work for natural gas compression.

With respect to the prime mover, an electric motor is more efficient, has higher reliability, and requires less maintenance.

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

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

RESPONSE:

Please refer to the response to BCUC IR 1.37.2.

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

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

1.6.3 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.

RESPONSE:

BC Hydro understands that it would not be an economically feasible alternative to provide redundancy by having both natural gas and electric driven equipment on site.

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

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

1.6.4 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.

RESPONSE:

BC Hydro understands that any compressor downtime would lead to an appreciable decline in natural gas production at the processing plant.

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

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

1.6.5 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.

RESPONSE:

With any downtime, production losses would be expected and result in revenue losses for the producer. As per the response to CEC IR 1.6.4, any incremental periods of downtime deteriorate the economics. As noted in the response to CEC IR 1.6.1, higher reliability electric motor driven compression provides an economic advantage over natural gas drives with respect to downtime. Reliability of energy supply to the compressor would be factored into the economic decisions by gas producers prior to requesting electric services.

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

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

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

RESPONSE:

Please refer to the responses to BCUC IRs 1.38.4 and 1.43.1.

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

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

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

RESPONSE:

Please refer to the response to BCUC IR 1.38.4.

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

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

1.6.8 Please calculate the cost of GHG reduction in terms of $/tonne of CO2 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.

RESPONSE:

BC Hydro does not have the information to undertake such calculations, as it is dependant on the specific circumstances facing gas producers operating in the Montney region. In response to BCUC IR 1.38.4, BC Hydro has provided an indicative list of the various considerations individual companies make in determining whether or not to seek electricity service from BC Hydro, including the potential for reducing GHG emissions.

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.

1.7.1 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.

RESPONSE:

BC Hydro believes its outlook for future compression loads is reasonable because this forecast was informed by third-parties such as industry experts, government estimates, and information from regional gas producers.

BC Hydro recognizes that forecasting events further in the future have inherent uncertainty, which also applies to setting probability distributions against potential discount rates in the long run. However, given the potential volume of gas in the region, BC Hydro reasonably expects some decline in production rates beyond 2027.

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.

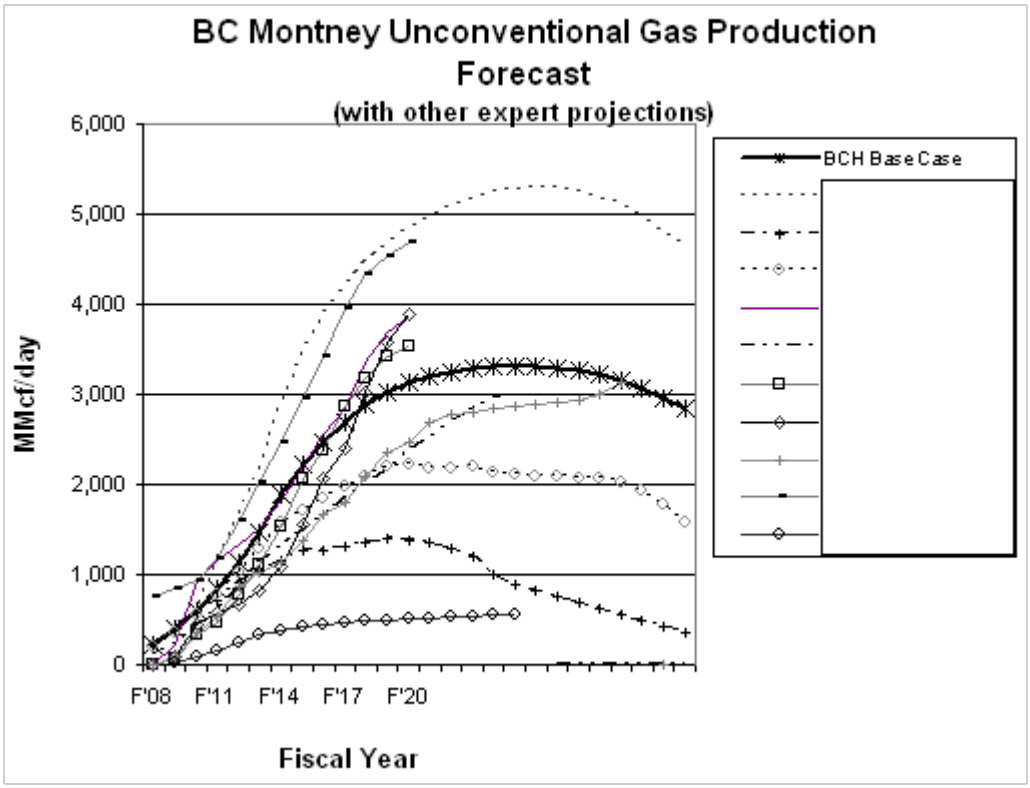
1.7.2 Please describe the certainty BC Hydro has with respect to the growth rates for the compression loads, in terms of a probability distribution across the range of potential growth rates.

RESPONSE:

BC Hydro believes its growth projection of compression loads is reasonable. BC Hydro undertook an extensive review of various sources including industry experts, government estimates, and information from regional gas producers to determine its project growth in compression loads.

Figure A3.3 of BC Hydro's 2010 Electric Load Forecast, filed as Appendix 3.2, Exhibit B-4, of the Ruskin Dam and Powerhouse Upgrade Project Application summarizes the review and is presented below for ease of reference. Pages 83 and 84 of Appendix B, Exhibit B-1 also describes the review.

This figure shows that BC Hydro's projected growth in gas compression is in the middle of the other expert projections. In addition the spread amongst all the projections in the growth period is a relatively tight distribution.


BC Montney Unconventional Gas Production Forecast
(with other expert projections)
6,000
5,000
4,000
3,000
2,000
1,000
0
MMcf/day
F'08
F'11
F'14
F'17
F'20
Fiscal Year
BCH Base Case

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.

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

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.

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.

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

RESPONSE:

The DSM savings shown graphically in Figure 2-4 on page 2-11 of Exhibit B-1 as MW capacity savings are the usual BC Hydro DSM savings.

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.

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

RESPONSE:

Yes.

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.

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

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.

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.

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

RESPONSE:

BC Hydro has been in discussions with customers with respect to their needs for reliability and understands that they require a high level of reliability. Generally BC Hydro provides information on transmission system reliability, and customers make their own business decision as to whether to take electric service.

Please refer to the response to CECBC IR 1.6.5 for further information on reliability requirements for compression load customers.

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.

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

RESPONSE:

Please refer to the response to CEC IR 1.8.5.

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.

1.9.1 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?

RESPONSE:

A conceptual review was undertaken to determine how the addition of 75 MW of dependable generation capacity would affect transmission system limits on the loss of 1L377. It was found that approximately 150 MW of load could be connected to the Dawson Creek area under this scenario to stay within voltage stability limits depending on where loads are interconnected. Detailed study would be required to assess the feasibility of such a scenario.

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.

1.9.2 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?

RESPONSE:

To determine the effect on voltage stability resulting from an interconnection to a substation in Alberta, detailed planning studies would be required to evaluate the type of interconnection, the choice of voltage (138 kV or 230/240 kV), the number of circuits, the transmission conductor sizing, and the generation and load patterns in Alberta as well as other undefined transmission and station upgrades such as phase shifting transformer(s) that might be necessary. Such planning studies are unwarranted in the circumstances given that other viable alternatives for supply from facilities within B.C. are available.

The Northwest region of Alberta is already a generation deficit region that imports over half of its power requirements from other regions within Alberta. It is an area that is already prone to voltage stability issues which will not be resolved until two of the Alberta Electric System Operator's proposed transmission reinforcements to the area are in service in 2015 and 2017. In addition, the challenges associated with meeting consultation and permitting requirements for new transmission facilities in Alberta do not lend support to consideration of a new intertie with Alberta as an alternative for reinforcing the Dawson Creek and Ground Birch areas in a timely manner.

Please refer to Exhibit B-1 Appendix B pages 63 and 64.

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.

1.10.1 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?

RESPONSE:

The N-1 load serving capability in the Dawson Creek area is not a function of the least capability of 1L377, 1L358 and 1L361. These lines have similar thermal capacities and electrical properties. The load serving capability in the Dawson Creek area is limited by voltage constraints from the loss of 1L377. Please refer to the response to CEC IR 1.2.2 for a description of how thermal and voltage limits are considered when defining system transfer limits.

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.

1.10.2 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?

RESPONSE:

The N-0 transmission capacity into the Dawson Creek area is constrained by voltage and not transmission line thermal capacities. Therefore in this case, 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.

Please refer to the response to CEC IR 1.2.2 which provides a description of the considerations and method used to determine the N-0 transmission capability.

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.

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

RESPONSE:

The maximum transfer capability from CWD to BMT would be approximately 90 MW in a system where, hypothetically, sufficient reactive power compensation was located to resolve all voltage constraints.

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.

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

RESPONSE:

Under system normal conditions (N-0), approximately 100 MVAR of additional reactive power compensation would be required to support 90 MW transfer capability from CWD to BMT. Adding MVAR support at this level is not considered practical. Such an approach would also not satisfy N-1 planning criteria because the thermal ratings of the transmission lines would be exceeded.

To reach the thermal constraints in CWD to BMT, thermal constraints in other parts of the system would need to be resolved.

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.

1.10.5 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?

RESPONSE:

A conceptual review was undertaken to determine how the addition of 75 MW of dependable generation capacity would affect transmission system limits on the loss of 1L361. It was found that approximately 150 MW of load could be connected to the Dawson Creek area under this scenario to stay within voltage stability limits depending on where loads are interconnected. Detailed study would be required to assess the feasibility of such a scenario.

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.

1.10.6 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?

RESPONSE:

Please refer to the response to CEC IR 1.9.2.

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.

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

RESPONSE:

A planning level estimate for a single circuit wood pole line from BMT to DAW is approximately $12.5 million based on direct costs only, with an accuracy level of +100/-50 per cent. This includes the costs for the line, a 138 kV line position at BMT, a 138 kV line position at DAW, and completion of the 138 kV ring bus at DAW.

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.

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

RESPONSE:

Assuming the Project is in service, power transfer capability for an added 138 kV line from BMT to DAW would be approximately 160 MVA during winter conditions.

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

2.4.1.5 Thermal Limits and Low Voltage - System Normal Conditions

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

1.12.1 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?

RESPONSE:

The Electricity Supply Agreement (Electric Tariff Supplement No. 5) applies to transmission voltage customer and under Suspension of Supply – Clause 17(c), BC Hydro in the event of a shortage of electricity may request that the customer suspend or reduce its taking of electricity. Similarly, under the general provisions of the Electric Tariff, BC Hydro will endeavor to provide a regular and uninterrupted supply of electricity but it does not guarantee a constant supply of electricity.

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

2.4.1.5 Thermal Limits and Low Voltage - System Normal Conditions

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

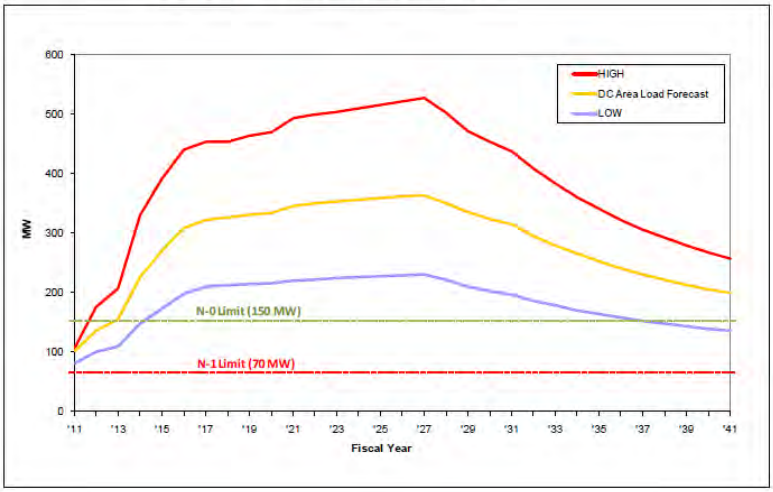
1.12.2 What are the terms and conditions in the ESAs which BC Hydro has with customers in this area that would govern outages of one of the system elements for supply to the area that would govern the actions BC Hydro would take to avoid thermal constraints arising from a single transmission line outage?

RESPONSE:

Please refer to the response to CEC IR 1.12.1.

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

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



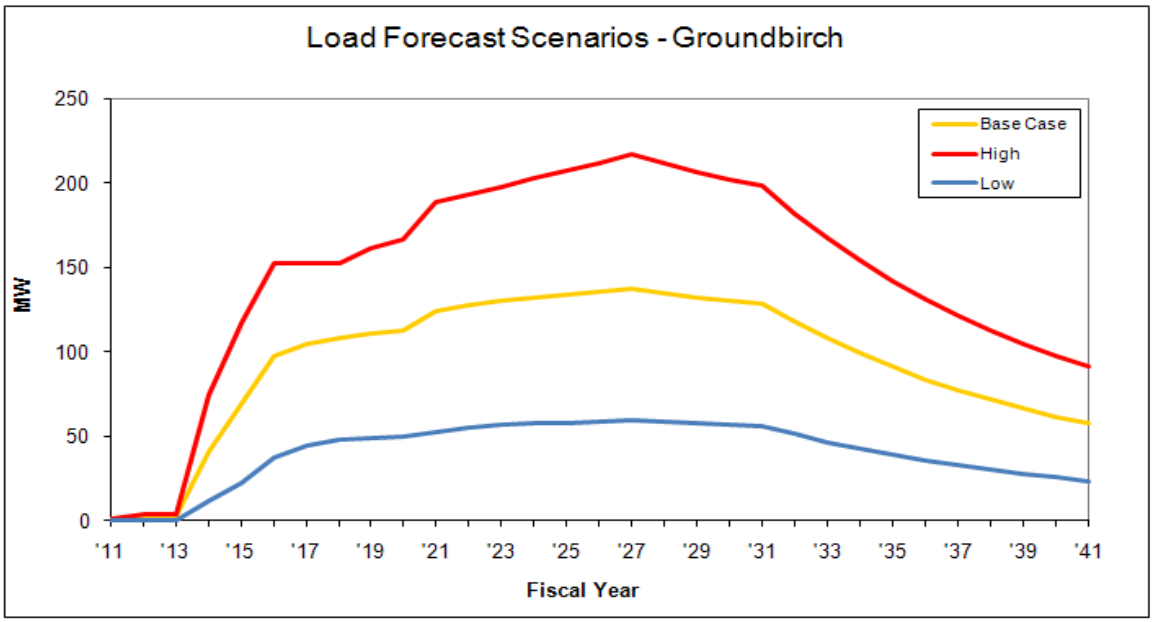
1.13.1 Please provide 3 graphs comparable to Figure 2-5, one each for Groundbirch loads, loads to be serviced from BMT and for load to be serviced from DAW.

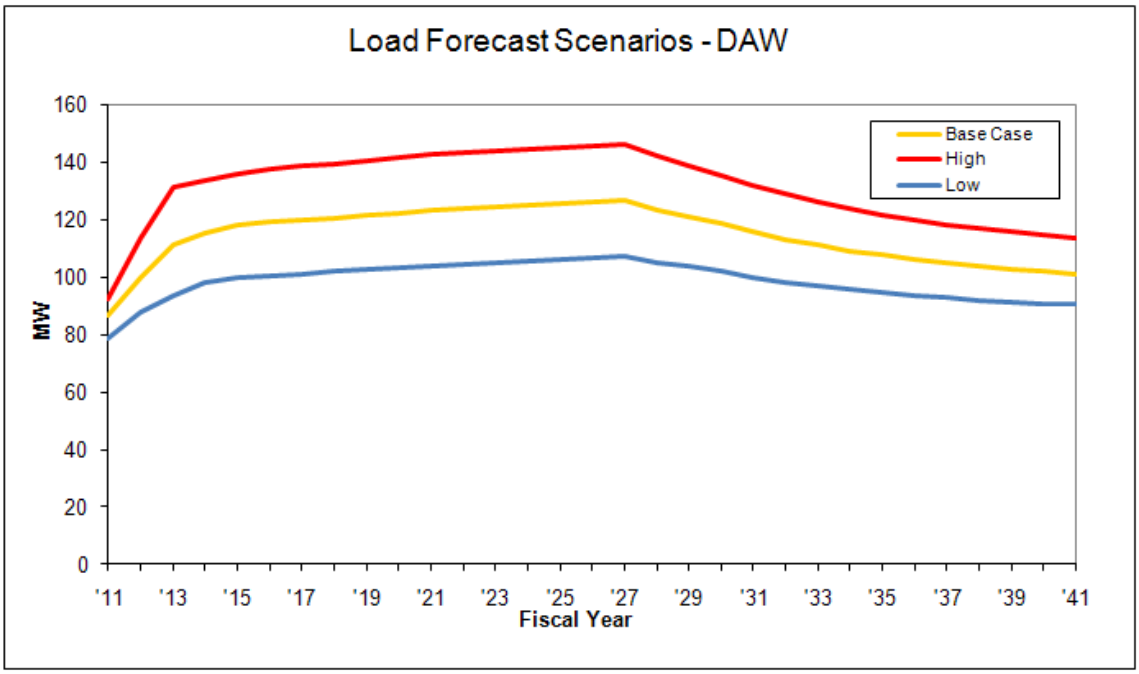
RESPONSE:

The following three figures show the forecast scenarios for Groundbirch and the Dawson Creek areas. The Dawson Creek area loads have been separated into loads served from DAW and those served from BMT.

Loads served from DAW include any transmission voltage customer loads connected to 1L377 and the loads served from the Dawson Creek Substation. Load served from BMT include all other loads in the Dawson Creek area.

There exists some uncertainty as to whether some loads will be served from BMT or DAW. Therefore, the following figures provide one possible load supply scenario. A point of interconnection will be assigned to each of the future transmission customers load on the completion of a system impact study after the customers make an application for interconnection.


Load Forecast Scenarios - Groundbirch
MW
250
200
150
100
50
0
'11
'13
'15
'17
'19
'21
'23
'25
'27
'29
'31
'33
'35
'37
'39
'41
Fiscal Year
Base Case
High
Low


Load Forecast Scenarios - DAW
MW
160
140
120
100
80
60
40
20
0
'11
'13
'15
'17
'19
'21
'23
'25
'27
'29
'31
'33
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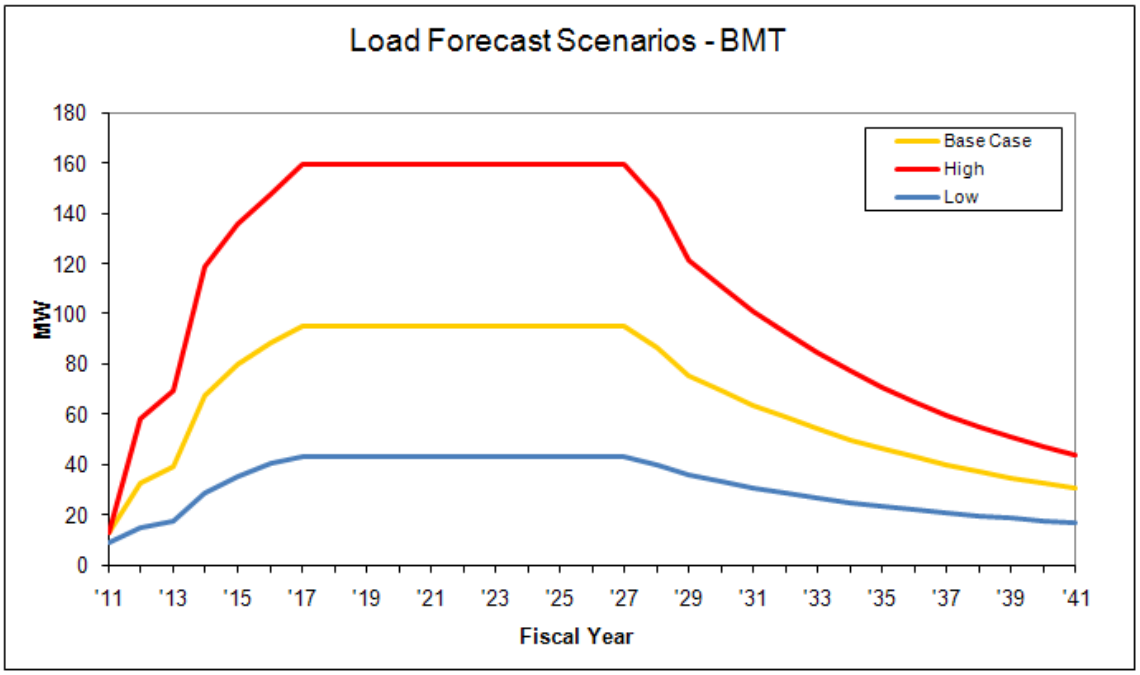
'39
'41
Fiscal Year
Base Case
High
Low


Load Forecast Scenarios - BMT
Base Case
High
Low
MW
180
160
140
120
100
80
60
40
20
0
'11
'13
'15
'17
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'33
'35
'37
'39
'41
Fiscal Year

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.

1.14.1 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?

RESPONSE:

BC Hydro expects that incremental customer loads will use the capacity provided by the DCAT Project, as evidenced by the letters put forward by customers (please refer to the response to BCUC IR 1.38.2.3).

Prevailing market conditions in the long term have the potential to affect the timing of Montney gas projects. BC Hydro has not quantified the probability of each or any project being delayed.

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

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

1.15.1 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?

RESPONSE:

BC Hydro understands that the emissions in the range of one million tonne per year is approximate, and the avoided/reduced GHG emissions would be expected to vary with the volume of gas production for which the compression requirements is supplied with clean energy. Please refer to the responses to BCSEA IRs 1.8.1 and 1.8.3.

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

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

1.15.2 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.

RESPONSE:

Please refer to the response to BCSEA IR 1.8.3.

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

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

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

RESPONSE:

Please refer to the response to BCUC IR 1.35.1.

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

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

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

RESPONSE:

The Project is being advanced in response to customer requests for electricity service and from general load growth in the Groundbirch and Dawson Creek areas. BC Hydro has not incurred any additional costs for the Project in relation to GHG reductions that will occur as a result of customers using electricity for gas compression. Given no additional costs have been incurred for GHG reductions related to this Project, BC Hydro has not determined any cost limits.

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.

1.16.1 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.

RESPONSE:

The transmission voltage customers will be served on Rate Schedule 1823 and the distribution voltage customers will be served on Rate Schedule 1611. These Rate Schedules are attached.

Given that rate increases are subject to BCUC approval, BC Hydro has not attempted to forecast rate increases.

SCHEDULE 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability: For Customers who qualify for General Service and whose Billing Demand (determined under the Special Conditions below) is equal to or greater than 150 kW, or whose energy consumption in any 12 month period is greater than 550,000 kW.h. Supply is 60 hertz, single or three phase at secondary or primary potential. BC Hydro reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I.

Charges: Basic Charge

18.53 ¢ per day

Demand Charge

First 35 kW of Billing Demand per Billing Period	@ $0.00 per kW
Next 115 kW of Billing Demand per Billing Period	@ $4.51 per kW
All additional kW of Billing Demand per Billing Period	@ $8.66 per kW

Energy Charge

Except for Customers being billed under "1. Energy Charge – Customers without HBLs", BC Hydro will determine monthly Historical Baselines ("HBLs") and related Billing Baselines ("BBLs") for use in calculating the Energy Charge payable by a Customer in a Billing Period.

1. Energy Charge – Customers without HBLs

Energy Charges will be determined under this part for Customers for whom no HBLs were determined by BC Hydro under the Special Conditions below at the time they commenced taking service under this rate schedule. The Energy Charges under this part will apply until they have taken service for a period of 12 consecutive months.

Energy Charge:

For the first 85% of energy consumption in the Billing Period the following rates are applied:

First 14,800 kW.h of energy consumption in the Billing Period @ Tier 1 rate of 8.85 ¢ per kW.h.

All additional kW.h of energy consumption in the Billing period @ Tier 2 rate of 4.26 ¢ per kW.h.

Remaining 15% of energy consumption in the Billing Period @ 6.68 ¢ per kW.h which is the marginal cost based energy rate.

2. Energy Charge – Customers with HBLs

Energy Charges will be determined under this part for:

1. Customers for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below at the time they commenced taking service under this rate schedule, and
2. Customers for whom HBLs were determined by BC Hydro in accordance with the Special Conditions below after completion of 12 consecutive months of service under this rate schedule.

The Energy Charge is the Part 1 Energy Charge plus any additional charges or minus any credits determined under the Part 2 Energy Charge/Credit below.

Part 1 Energy Charge

The following rates are applied to the Customer's BBL for the Billing Period:

First 14,800 kW.h of the BBL for the Billing Period @ the Tier 1 rate of 8.85 ¢ per kW.h.

Additional kW.h of BBL for the Billing Period @ the Tier 2 rate of 4.26 ¢ per kW.h.

Part 2 Energy Charge/Credit

The determination of the Part 2 Energy Charge/Credit depends on whether energy consumption in the Billing Period is greater or less than the Customer's BBL for the Billing Period.

Consumption greater than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Greater Than Baseline".

Charge is based on the following three steps:

1. The marginal cost based energy rate of 6.68 ¢ per kW.h is applied to Consumption Greater Than Baseline subject to a maximum of 20% of the BBL.

2. Tier 1 rate of 8.85 ¢ per kW.h is applied to the lesser of:

   (a) the remaining portion of the Consumption Greater Than Baseline (if any) following step 1 above, and
   (b) that portion of the Consumption Greater Than Baseline which is equal to 14,800 kW.h minus 120% of the BBL (but if 14,800 kW.h minus 120% of the BBL would produce a negative number, the result shall be deemed to be zero).

3. Tier 2 rate of 4.26 ¢ per kW.h is applied to the remaining portion of the Consumption Greater Than Baseline (if any) following steps 1 and 2 above.

Consumption less than BBL

For purposes of the following calculations, the difference between the BBL and the energy consumption for the Billing Period is defined as the "Consumption Less Than Baseline".

Credit is based on the following three steps:

1. The marginal cost based energy rate of 6.68 ¢ per kW.h is applied to the Consumption Less Than Baseline subject to a maximum of 20% of the BBL.

2. Tier 2 rate of 4.26 ¢ per kW.h is applied to the lesser of:
   (a) the remaining portion of the Consumption Less Than Baseline (if any) following step 1 above, and
   (b) that portion of the Consumption Less Than Baseline which is equal to 80% of the BBL minus 14,800 kW.h (but if 80% of the BBL minus 14,800 kW.h would produce a negative number, the result shall be deemed to be zero).

3. Tier 1 rate of 8.85 ¢ per kW.h is applied to the remaining portion of the Consumption Less Than Baseline (if any) following steps 1 and 2 above.

Minimum Energy Charge (Applicable to Energy Charge 2.):

The Minimum Energy Charge is the minimum energy rate of 2.70 cents per kW.h multiplied by the total energy consumption in the Billing Period. The Minimum Energy Charge applies only when the average energy rate in a Billing Period (the Energy Charge 2. divided by total energy consumption in the Billing Period) is less than the minimum energy rate.

Discounts

1. A discount of 1½% shall be applied to the above charges if a Customer's supply of electricity is metered at a primary potential.

2. A discount of 25¢ per billing period per kW of billing demand shall be applied to the above charges if a Customer supplies transformation from a primary potential to a secondary potential.

3. If a Customer is entitled to both of the above discounts, the discount for metering at a primary potential shall be applied first.

Billing Codes:	Schedule 1600	applies if a Customer's supply of electricity is metered at a secondary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.
	Schedule 1601	applies if a Customer's supply of electricity is metered at a primary potential and BC Hydro supplies transformation from a primary potential to a secondary potential.
	Schedule 1610	applies if a Customer's supply of electricity is metered at a secondary potential and the Customer supplies transformation from a primary potential to a secondary potential.
	Schedule 1611	applies if a Customer's supply of electricity is metered at a primary potential and the Customer supplies transformation from a primary potential to a secondary potential.

Billing Demand: The Billing Demand shall be the highest kW demand in the Billing Period.

Monthly Minimum Charge: 50% of the highest maximum Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding eleven Billing Periods. For the purpose of this provision an on-peak period commences on 1 November in any year and terminates on 31 March of the following year.

Metering: A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the Billing Demand shall be estimated by BC Hydro.

ACCEPTED: JAN 21 2011
ORDER NO. G-110-10

COMMISSION SECRETARY

Definitions:

For purposes of this rate schedule, unless the context otherwise requires, the following terms have the following meanings:

"Billing Period" means a period of from 27 to 33 consecutive days between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

"HBL Reference Period" means a period of at least 12 consecutive months or at most 36 consecutive months during which the Customer was taking service under any of Rate Schedules 1200, 1201, 1210 or 1211 during all or part of (i) the 3-year period commencing January 1, 2005 or (ii) the 3-year period commencing July 1, 2007, whichever 12 consecutive months or longer period has the higher energy consumption.

"month" and "monthly" refers to calendar months.

"Significant Growth" means that the Customer's energy consumption in the most recent 12 month period commencing January 1 that the Customer has taken service under this rate schedule exceeds the energy consumption in the previous 12 month period commencing January 1 by at least (i) 30% or (ii) 4,000,000 kW.h.

"year" means a period of 12 consecutive calendar months.

"Year 1", "Year 2", "Year 3" and similar designations means the first, second and third years that the Customer takes service under this rate schedule and for which HBLs have been determined by BC Hydro under the Special Conditions below, and so on as the context requires.

Special Conditions:

3. Determination of HBLs and BBLs for Energy Charge 2.:

BC Hydro will determine monthly HBLs and BBLs for each Customer taking service under this rate schedule as specified in this part.

3.1 Baseline Determinations - General

For Customers taking service under this rate schedule, other than Customers to whom "1. Energy Charges – Customers without HBLs" applies, BC Hydro will determine Historical Baselines ("HBLs") and Billing Baselines ("BBLs") in accordance with these Special Conditions, for use in calculating the Energy Charge payable by the Customers for each Billing Period.

ACCEPTED: JAN 21 2011
ORDER NO. G-110-10

COMMISSION SECRETARY

The HBLs will be determined based on the Customers' historical energy consumption each month, and the BBL will be determined from the Customers' HBLs for the months that overlap the Billing Period, all as described in these Special Conditions.

3.2 Determination of Initial (Year 1) HBLs

3.2.1 For Customers to whom the definition of HBL Reference Period applies and who would have been eligible for service under this rate schedule during the HBL Reference Period, the Customers' Year 1 HBLs will be determined as follows:

(a) The Customers' energy consumption during each Billing Period in the HBL Reference Period will be allocated to the months which overlap those Billing Periods as set out in section 3.6 of these Special Conditions.
(b) The Customers' HBLs will be determined for each month as the average of the energy consumption for the applicable months as referred to in (a) above.

3.2.2 For Customers to whom paragraph 3.2.1 is not applicable but who were taking service under any of rate schedules 1200, 1201, 1210 or 1211 for a period of 12 consecutive months or longer ending immediately prior to the date this rate schedule comes into effect and whose Billing Demand was equal to or greater than 150 kW in any one of the 12 most recent months or whose energy consumption in the most recent 12 month period is greater than 550,000 kW.h, the Customers' Year 1 HBLs will be determined as the amount of the Customers' energy consumption during each month for the preceding 12 month period. For these purposes the Customers' energy consumption during each Billing Period will be allocated to the months which overlap those Billing Periods as set out in section 3.4 of these Special Conditions.

3.2.3 For Customers to whom paragraphs 3.2.1 and 3.2.2 are not applicable but who were taking service under any of rate schedules 1500, 1501, 1510 or 1511 for a period of 12 consecutive months or longer immediately prior to becoming subject to this rate schedule in accordance with the Migration Rule below, the Customers' Year 1 HBLs will be determined as the amount of the Customers' energy consumption during each month for the preceding 12 month period. For these purposes the Customers' energy consumption during each Billing Period will be allocated to the months which overlap those Billing Periods as set out in section 3.4 of these Special Conditions.

ACCEPTED: JAN 21 2011
ORDER NO. G-110-10

COMMISSION SECRETARY

3.2.4 For Customers to whom paragraphs 3.2.1, 3.2.2 and 3.2.3 are not applicable, the Customers' Year 1 HBLs will be determined after the end of the first twelve months that the Customers take service. The HBLs will be determined as the amount of the Customers' energy consumption during each month for the preceding 12 month period. For these purposes the Customers' energy consumption during each Billing Period will be allocated to the months which overlap those Billing Periods as set out in section 3.4 of these Special Conditions.

3.3 Re-Determination of HBLs

3.3.1 Except as provided in paragraph 3.3.2 below, Customers' HBLs will be re-determined by BC Hydro as follows:

(a) Year 2 HBLs will be determined as the sum of the Year 1 HBL and the Customer's energy consumption for that month during Year 1, divided by 2.
(b) Year 3 HBLs will be determined as the sum of the Year 1 HBL and the Customer's energy consumption for that month during Year 1 and Year 2, divided by 3.
(c) Year 4 HBLs and HBLs for each succeeding year of service will be determined on a 3-year rolling-average basis, being the sum of the Customer's energy consumption each month during the most recent 3 years of service under this rate schedule, divided by 3.

3.3.2 For Customers experiencing Significant Growth in energy consumption during the most recent 2-year period, the Customers' HBLs for the upcoming 12 month period commencing April 1 will be re-determined by BC Hydro as the sum of the Customer's energy consumption each month during that 2-year period, divided by 2.

3.4 Pro-rating of Energy Consumption Data

For purposes of determining (or re-determining) Customers' HBLs on a monthly basis, where energy consumption for Billing Periods in prior years is being used to determine the Customer's HBLs and any of the Billing Periods begins in one month and ends in a subsequent month, BC Hydro will pro-rate the energy consumption for each such Billing Period on a daily basis and allocate the pro-rated consumption to the respective overlapping months.

ACCEPTED: JAN 21 2011
ORDER NO: G-11-10

COMMISSION SECRETARY

3.5 Adjustment for Anomalies

3.5.1 Despite anything in the preceding sections of these Special Conditions, if in making any determination or re-determination of a Customer's HBLs BC Hydro observes any anomaly in the historical energy consumption information that would otherwise be used in making the HBL determination, the Customer's HBLs shall be subject to adjustment in accordance with this paragraph. For these purposes an "anomaly" is defined to occur whenever, in cases where the HBLs are based on the most recent 2 or 3 years' consumption, the consumption in a month is less than 50% of the next lowest consumption for that same month in either of the other 1 or 2 years, as the case may be. Subject to the restrictions in paragraph 2 below, whenever an anomaly occurs the lowest month's consumption shall be discarded for purposes of determining the HBL for that month, and the HBL shall be determined as the average of the remaining 1 or 2 months' consumption as applicable.

3.5.2 No anomalies will be deemed to exist or be considered until after, for a given month, 2 years of consumption information is available for that month. Further, the maximum number of anomaly adjustments in a year, commencing on April 1 each year, shall be 4, and they shall be made in the order in which they appear.

3.6. Determination of BBLs

For purposes of applying the rates set forth in this rate schedule and issuing bills to Customers on a Billing Period basis, where a Billing Period begins in one month and ends in a subsequent month BC Hydro will determine the Customer's BBL for each Billing Period as follows. BC Hydro will calculate a daily HBL amount for each month which overlaps the Billing Period in question and will allocate the daily HBL amount to the Billing Period based on the number of days in each month which overlaps the Billing Period. The sum of the HBL amounts prorated to the Billing Period in accordance with the preceding is the Customer's BBL for that Billing Period.

ACCEPTED: JAN 21 2011
ORDER NO. G 1 10 10

COMMISSION SECRETARY

SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability: For all purposes. Supply is at 60,000 volts or higher. Customers being supplied with electricity under Schedule 1825 (Transmission Service Time-of-use) may only revert to service under this Schedule as permitted under Schedule 1825.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Demand Charge: $6.027 per kV.A of Billing Demand per Billing Period.

Plus

Energy Charge:

A. For new Customers and Customers that do not have a CBL by Order of the British Columbia Utilities Commission:

3.533 ¢ per kW.h for all kW.h per Billing Period

This rate will apply until the Customer has been supplied with Electricity under this Schedule for 12 Billing Periods or other period with the approval of the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the Rate specified in Part B below.

B. For Customers with a CBL:

3.108 ¢ per kW.h applied to all kW.h up to and including 90% of the Customer's CBL in each Billing Year.

7.360¢ per kW.h applied to all kW.h above 90% of the Customer's CBL in each Billing Year.

Note: Customers previously supplied with electricity under Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking service under this Schedule.

Billing Year: The Billing Year is the 12 billing month period starting with the first day of the Billing Period which commences nearest to April 1st in each year, and ending on the last day of the 12th Billing Period thereafter.

Billing Demand:	The Demand for billing purposes shall be: 1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or 2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or 3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value, provided that for new Customers the Billing Demand for the initial 2 Billing Periods shall be the average of the daily highest kV.A Demands for the Customer's Plant. The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays. The LLH period is defined as all other hours. Statutory Holidays for the purpose of this Schedule are New Years Day, Good Friday, Victoria Day, Canada Day, B.C, Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day.
Monthly Minimum Charge:	$6.027 per kV.A of Billing Demand
Customer Baseline Load:	The Customer Baseline Load (CBL) is the Customer's historic annual energy consumption in kW.h as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines". All CBLs will be subject to final approval of the British Columbia Utilities Commission.
Aggregation of Customer Baseline Load:	A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with the CBL Determination Guidelines. Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the energy charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

Energy Determination under Retail Access:

If the Customer has entered into a Retail Access Program Agreement that is in effect, the quantity of Schedule 1823 energy is defined as the total metered kW.h consumption of the Customer's Plant less the Net Scheduled Output. The Net Scheduled Output is the Gross Scheduled Output adjusted by the Energy Loss Adjustment Factor of 6.28%. The Net Scheduled Output and Gross Scheduled Output are as defined in the Retail Access Program Agreement. If the Net Scheduled Output is greater than the total metered kW.h consumption of the Customer's Plant, then the quantity of Schedule 1823 energy is zero.

Special Conditions:

The following Special Conditions are applicable to this Schedule:

1. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.

2. If a Customer taking service at the rates in Part B of the Energy Charge rate section above terminates service under this Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking service, and the prorated CBL or aggregate CBL will be used for purposes of applying the rates in Part B to all electricity consumption during the Billing Year up to the time of termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.

Taxes:

The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Services tax.

Note:

The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6.

Rate Rider:

The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Interim Increase:

Effective May 1, 2011 the Rates and Minimum Charge under these schedules include an increase of 8% before rounding, approved by BCUC Order No. G-72-11.

ACCEPTED: May 18, 2011

ORDER NO. G-72-11

ACTING COMMISSION SECRETARY

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.

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

RESPONSE:

The estimated customer revenue based on the Gas Producer Forecast shown in Exhibit B-1 Appendix B, page 82 of 100 is provided in the table below. Given that rate increases are subject to BCUC approval, BC Hydro has not attempted to forecast rate increases in this estimate.

Fiscal Year	Demand (MW)	Energy (GWh)	Estimated BC Hydro Revenues ($)
F2011	41	191	9,725,161
F2012	70	439	20,722,265
F2013	83	593	27,086,720
F2014	153	1,035	47,898,256
F2015	195	1,325	61,233,951
F2016	233	1,597	73,651,455
F2017	246	1,714	78,757,952
F2018	249	1,757	80,494,730
F2019	252	1,780	81,566,772
F2020	254	1,792	82,102,793
F2021	265	1,870	85,706,014
F2022	268	1,892	86,700,352
F2023	272	1,915	87,763,174
F2024	273	1,927	88,299,195
F2025	275	1,938	88,835,216
F2026	277	1,950	89,371,237

Fiscal Year	Demand (MW)	Energy (GWh)	Estimated BC Hydro Revenues ($)
F2027	**278**	**1,962**	**89,907,258**
F2028	**263**	**1,858**	**85,134,360**
F2029	**247**	**1,743**	**79,883,346**
F2030	**235**	**1,661**	**76,112,839**
F2031	**225**	**1,587**	**72,719,383**
F2032	**206**	**1,456**	**66,680,065**
F2033	**189**	**1,337**	**61,244,678**
F2034	**174**	**1,230**	**56,352,830**
F2035	**160**	**1,135**	**51,950,167**
F2036	**148**	**1,048**	**47,987,771**
F2037	**137**	**971**	**44,421,614**
F2038	**127**	**901**	**41,212,072**
F2039	**118**	**838**	**38,323,485**
F2040	**110**	**781**	**35,723,757**
F2041	**103**	**730**	**33,384,001**

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.

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

RESPONSE:

BC Hydro believes that the most appropriate energy price for estimating the cost to supply these customer loads is the price resulting from the most recent BC Hydro competitive power acquisition process because such power acquisition processes provide a reasonable indicator of B.C. market prices. The Clean Power Call concluded in August 2010 is the most recent, broadly based, competitive power acquisition process that resulted in a firm energy price of $129/MWh (2011$).

With respect to the above reference, BC Hydro notes that the discussion on page 2-17 of Exhibit B-1 was intended to reflect the impacts of embedded cost rates.

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.

1.16.4 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.

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.

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.

1.16.5 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.

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.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.16.6** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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.

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

RESPONSE:

BC Hydro has not assessed the economic impacts for the Province related to supplying these particular customers.

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.

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

RESPONSE:

No.

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.

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

RESPONSE:

BC Hydro understands a gas producer's gathering compression energy represents approximately 15 to 25 per cent of their operating costs.

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

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

1.18.1 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.

RESPONSE:

As noted on page 2-17 of Exhibit B-1, gas producers have the option of using natural gas compression in the absence of BC Hydro supply. 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. Nevertheless, the development of the Montney basin and economic development in the province is unlikely to be significantly impacted by the availability of BC Hydro supply.

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

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

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

RESPONSE:

The improvements to system capacity provided by the DCAT Project is 115 MW above current limits at N-1 planning criteria of 70 MW (i.e., 185 MW). The DCAT Project on its own does not result in underutilized capacity over the planning period. The Project provides an appropriate foundation such that additional capacity can be added to the system when needed.

Additional capacity will be achieved through further system upgrades in a future project to meet the Load Forecast over the 30-year planning cycle. To evaluate DCAT Project alternatives, the planning report includes a notional F2016 stage upgrade which is further discussed at Exhibit B-1, Appendix B page 94 of 100.

Capacity improvements for the DCAT Project and a notional F2016 stage upgrade are discussed at Exhibit B-1, Appendix B pages 50 and 51 of 100.

BC Hydro is seeking approval of the DCAT Project in this Application. Possible future upgrades require further studies and will be addressed in a future application if and when required.

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

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

1.20.1 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?

RESPONSE:

BC Hydro believes the rationale for the allocation is appropriate and adequately protects ratepayers from the risk of stranded investment. Assuming a hypothetical project could deliver similar incremental capacity, BC Hydro would not expect the cost allocation to change.

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

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

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

RESPONSE:

The requested information has been provided in the response to BCUC IR 1.47.1 on a confidential basis.

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.

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

RESPONSE:

The question poses a hypothetical scenario that cannot be answered in the abstract. BC Hydro's response at the appropriate time would be fact dependant.

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.

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

RESPONSE:

The question poses a hypothetical scenario that cannot be answered in the abstract. BC Hydro's response at the appropriate time would be fact dependant.

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.

1.21.3 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.

RESPONSE:

Any proposed project that effectively addresses the 2014 requirements would also have to be evaluated against the needs identified over the 30-year planning period. In such a scenario, future upgrades to meet the identified needs would require definition. All upgrades required during the 30-year planning cycle would be included in an evaluation that compared alternatives.

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.

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

RESPONSE:

A common F2016 stage appropriately facilitates the evaluation of the DCAT alternatives over the 30-year study period. This includes expenditures for future transmission upgrades needed to meet the load forecast.

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.

1.21.5 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?

RESPONSE:

BC Hydro indicated at Exhibit B-1, page 3-2 that a decision to select among transmission alternatives for future (F2016) upgrades can be made independently from the decision among feasible alternatives for the DCAT Project.

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

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

1.22.1 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?

RESPONSE:

BC Hydro is bringing forward a Project for timely transmission systems upgrades that it considers optimal for the needs identified. The DCAT Project provides a foundational system which effectively supports foreseeable future transmission system upgrades which may be required to service the anticipated load growth in the region.

The alternatives considered are detailed in Exhibit B-1, Appendix B.

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

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

1.22.2 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?

RESPONSE:

BC Hydro does not believe that generation providing dependable capacity could be developed in the Dawson Creek area in time to meet F2014 requirements. The generation resource option that is a source of dependable capacity, and has the shortest development time, is gas-fired generation. BC Hydro believes it would take at least four to five years to permit and site a gas-fired generator and would not be a viable resource to meet F2014 requirements.

Please refer to the response to CEC IR 1.38.1 for the role of gas generation.

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

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

1.22.3 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?

RESPONSE:

BC Hydro will bring forward future transmission solutions as appropriate.

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

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

RESPONSE:

Not confirmed. The Dawson Creek area is defined by the area surrounding the City of Dawson Creek including transmission and distribution customer load as shown in Exhibit B-1, Figure 2-2, page 2-4. The firm capacity that serves Dawson Creek is for the entire area which includes DAW and other transmission elements such as BMT, SEP, NL2, NL3, NL5, BMW, KIS and other future transmission voltage customer loads.

Please note, however, the reference at line 5 above should refer to the Dawson Creek and Groundbirch areas as shown in Exhibit B-1, Figure 2-2, page 2-4.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.23.2** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 1 of 1
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**

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

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

RESPONSE:

Confirmed. The 185 MW transmission capacity is based on the loss of 2L312 from SNK to the new SLS.

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

1.23.3 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.

RESPONSE:

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.

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

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

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

RESPONSE:

Confirmed.

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

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

1.24.1 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.

RESPONSE:

Not confirmed. The 207 MW transmission capacity is based on the loss of 2L312 from SNK to the new SLS. This represents the most critical line outage.

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

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

1.24.2 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.

RESPONSE:

The contribution made to the firm capacity would be to increase the firm transmission capacity into the Dawson Creek and Groundbirch areas to 207 MW, as described in Exhibit B-1 Appendix B (page 46 of 100).

The interconnection with line 2L312 and the additional 138 kV transmission line improve firm transmission capacity by 1) resolving thermal constraints on 1L361, 1L358, and 1L377; and 2) improving voltage performance by reducing system impedance.

The 110 MVAR SVC improves firm capacity by supporting area voltages within an acceptable range by injecting reactive power into the system in response to changes in system voltages.

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

1.25.1 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		

RESPONSE:

The planning level (+100/-50 per cent) cost estimate breakdown of the F2014 and F2016 stage are provided below. Note that Table 3-2 of Exhibit B-1 shows capital expenditures and does not include the cost for dismantling the 138 kV lines because the cost to dismantle the transmission lines is an OMA expense. Therefore these OMA costs are not included in the tables below.

F2014 Stage

Alternative #1	**Direct $**	**PV $**
SLS 230 KV Substation	28,000,000	26,201,990
60 km 230 KV double circuit SLS to BMT	82,400,000	77,108,713
12 km 230 KV double circuit BMT to DAW	13,460,000	12,595,670
BMT 138 KV and 230 KV line and transformer positions	32,000,000	29,945,131
DAW complete 138 KV ring bus and 138 KV line position	4,000,000	3,743,141
Total	159,860,000	149,594,648

F2014 Stage

Alternative # 2	**Direct $**	**PV $**
SLS 230 -138 KV substation	28,000,000	26,201,990
60 km 138 KV line SLS to BMT	36,500,000	34,156,165
12 km 138 KV double circuit from BMT to DAW	6,950,000	6,503,708
110 MVA SVC at BMT	21,000,000	19,651,492
BMT 138 KV line and transformer positions	9,050,000	8,468,857
DAW complete 138 KV ring bus and 138 KV line position	4,000,000	3,743,141
Total	105,500,000	98,370,261

Note that the 60 km 138 KV line from SLS to BMT is composed of double circuit structures with one side strung at this time. To meet the High Load Forecast, the other 138 kV circuit would be required.

F2016 Stage

Common	**Direct $**	**PV $**
73 km 230 KV line GMS to SNK	37,800,000	30,512,793
30 km 230 KV line SNK to SLS	16,200,000	13,076,911
GMS 230 KV line position	4,500,000	3,632,475
replacement of 500/230 KV transformers	28,000,000	22,602,069
SNK line position	6,500,000	5,246,909
SLS line position	3,500,000	2,825,259
Total	96,500,000	77,896,416

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:

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

RESPONSE:

Confirmed.

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:

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

RESPONSE:

In order to supply customers on a reliable basis, BC Hydro meets customer needs with firm energy supply. Customer needs include the customer's load plus the loss incurred to deliver the energy. A reduction in losses will result in a comparable reduction in the firm energy supply that needs to be acquired.

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:

1.26.3 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?

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.

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:

1.26.4 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?

RESPONSE:

Please refer to the response to CEC IR 1.26.2.

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:

1.26.5 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?

RESPONSE:

Yes.

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:

1.26.6 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?

RESPONSE:

The August 2010 Clean Power Call Report shows the range of firm energy prices for the awarded EPAs was $105.4 to $133.8/MWh (in 2009$). Escalating these figures results in a price range of $110 to $139/MWh (in 2011$), or $129/MWh on a weighted-average basis. While there was a range of projects in the call, BC Hydro believes another acquisition process undertaken today would result in a similar range of projects and prices, and believes that this weighted average of new firm resource prices provides the best price signal to represent BC Hydro's cost of marginal supply side resource.

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:

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

RESPONSE:

Confirmed. The timing and volume of these acquisitions would change based on factors such as load growth and changes to self-sufficiency definitions and requirements.

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:

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

RESPONSE:

BC Hydro believes that the most appropriate energy price used for project evaluation is the price resulting from the most recent BC Hydro competitive power acquisition process because such power acquisition processes provide a reasonable indicator of B.C. market prices. In the case of the Project, the Clean Power Call is the most recent, broadly based, competitive power acquisition process. The analysis compares the value of the incremental supply resulting from reducing losses over a 30-year period to the price of alternative energy acquisitions that could be undertaken that would provide a similar product over a similar period.

While future energy costs cannot be known with any certainty, past experience suggests future IPP costs may be higher than the $129/MWh resulting from the Clean Power Call.

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:

1.26.9 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.

RESPONSE:

There is no change to assumed attrition rate for the Clean Power Call which remains at 30 per cent.

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:

1.26.10 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.

RESPONSE:

At this time, there is no known attrition for any of the Clean Power Call projects. The projects are in various stages of development and none of the EPAs have been terminated.

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:

1.26.11 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.

RESPONSE:

Confirmed.

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.

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

RESPONSE:

Although pre-stressed spun concrete poles are used at transmission voltages up to 138 kV, they are rarely used for 230 kV and above. At voltages of 230 kV and above, larger clearances between phases and to ground are required. This results in taller poles and larger overturning moments at the base. Steel poles are better capable of withstanding larger loads than concrete.

In addition, concrete poles are more vulnerable to damage during transit, storage and installation. They also involve significantly more handling than steel poles in shipping, storage and construction.

Also, unlike steel pole sections which can be designed to be shipped by "nesting" them telescopically, concrete pole sections need to be shipped separately. This results in

higher shipping costs and greater probability of transit damage. Also, greater storage space is required for separate concrete sections.

Concrete poles are also prone to micro-fractures and cracking over time, especially with the occurrence of high load events, and spalling below ground level. Steel poles, due to their greater inherent elasticity, do not suffer from this issue. This ensures safer long term performance and security.

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.

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

RESPONSE:

Hybrid poles (pre-stressed spun concrete base section, with steel upper sections) are designed to be placed into the ground without a foundation (i.e., directly embedded). For the loads that would be experienced by the proposed line, direct embedded poles are not recommended. The proposed lines need foundations designed to withstand the loads.

There are very few instances of hybrid pole usage for transmission lines, therefore there's little or no service history. Presently, only one manufacturer offers these poles.

Hybrid poles are being proposed on a short section of a 115 kV line in the U.S. as a replacement for lattice towers, with pole heights of about 25 m. The poles on the proposed DCAT line are from 35 to 40 m and significantly larger in diameter.

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.

1.27.3 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.

RESPONSE:

The basis for the line design is derived from an analysis of the various weather cases of wind/ice/snow loading that the line would be subjected to. These weather cases must comply with CSA, and other location specific standards as per BC Hydro practice. The line sag is determined by the governing weather case.

The calculation of sag is based on standard established sag-tension equations for catenaries (as defined in CIGRE` Technical Brochure TB324 – June 2007), as below.

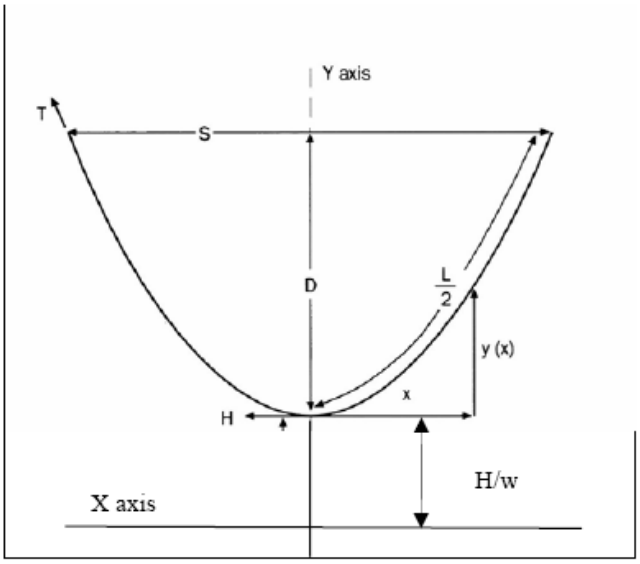


Figure 6 - The Catenary Curve for Level Spans

The catenary equation for a conductor between supports at equal heights or at different heights is the same. It is expressed in terms of the horizontal distance, x, from the vertex (or low point) of the catenary to a point on the catenary which is y(x) above the vertex. The catenary equation is given by:

$$y(x) = \frac{H}{w} \cdot \left[\cosh\left(\frac{w \cdot x}{H} \right) - 1 \right] \cong \frac{w \cdot x^2}{2 \cdot H} \qquad (1)$$

The industry standard line design software PLS-CADD is used. This software calculates the sag and tension values, for the entire length of the line, based on the above equation for each weather case. The software also optimizes the spans versus the pole heights to suit the terrain.

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.

1.27.4 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.

RESPONSE:

The circuit to circuit separation for a double circuit line is determined through conductor clashing calculations during high turbulent wind and/or snow/ice loading and shedding conditions. This separation distance would be larger for longer spans.

Structures with wider middle crossarms are common in Canada. They are designed to be wider to prevent the shed snow from the middle conductor falling directly on the conductor beneath it.

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.

1.27.5 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.

RESPONSE:

Construction of the line using monopoles with davit crossarms can achieve spans of about 400 m. Construction using compact design can achieve smaller average spans of about 250 m, which results in a higher number of structures.

In addition, compact design structures restrict maintenance work from the structure body, especially live-line maintenance, as safe clearance distances are not available. Live line maintenance may be possible in limited situations where bucket truck access is possible. The line therefore has to be completely

de-energised for maintenance in areas where bucket trucks cannot access the line.

Compact design structures with braced post insulators are also not as strong in withstanding unbalanced longitudinal/torsional loads such as those caused by a broken conductor, or snow shedding and ice build-up as may be expected in the Peace Region. As a result, compact structure design requires use of failure containment structures inserted throughout the line to prevent cascading failures.

The ROW requirement for compact designs is narrower (approximately 20 m as opposed to 33 m for davit arm) due to the smaller spans and consequently less conductor swing.

Compact structures may have limited application in this Project in isolated situations where there are restrictions on ROW widths due to the presence of dwellings in the vicinity of the route, or other similar restrictions.

With respect to ROW, compact design requires a narrower ROW, however, this does not translate into lower cost because of the higher costs associated with a higher number of pole placements.

Unit cost of construction of a monopole using a davit arm structure is in the range of $160,000 to $180,000; as compared to the unit cost of construction of $110,000 to $120,000 for a compact structure.

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.

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

RESPONSE:

The trade-off between pole heights and pole spacing (span lengths) is an exercise in optimality analysis.

The following table describes the advantages and disadvantages:

Large spans	***Small spans***
Fewer number of poles are required	**Greater number of poles are required**
Taller poles required	**Shorter poles required**
High unit pole costs	**Lower unit pole costs**
Larger Foundations	**Smaller foundations**
High unit foundation costs	**Lower unit foundation costs**
Less insulators and hardware	**More insulators and hardware**
Less construction costs	**Higher construction costs**

Large spans	***Small spans***
Less land impact & issues	**More land impact and issues**
Less maintenance	**Higher maintenance**
Wider ROW	**Narrower ROW**

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.

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

RESPONSE:

The ROW width is determined by calculating the horizontal displacement of the insulator and conductor (at the point of maximum sag) when exposed to transverse wind pressure (determined by CSA and BC Hydro standards for the region), and adding to it the safe CSA/BC Hydro clearances distances on each side. The horizontal displacement is a function of conductor type, insulator configuration, weather conditions and conductor tension. This calculation is done for a 90 per cent span within a ruling span section.

For a double circuit line, such as the proposed, this calculation would be as follows:

Circuit to Circuit distance + Horizontal component of insulator and conductor swing + (safe side clearance distance x 2).

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.

1.28.2 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.

RESPONSE:

For a double circuit line such as the proposed, the bottom conductors are closest to the ground, and therefore present the greatest risk for a breach of safe clearance distances as defined in CAN/CSA-C22.3 No. 1-10. The conductors of the other phases are located above the lowest phase by about 5.5 to 6 m.

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.

1.28.3 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.

RESPONSE:

Please refer to the response to CEC IR 1.28.1.

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).

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

RESPONSE:

Yes, it is expected that some of the cleared trees will be timber quality. A preliminary analysis was included in the EOA; please refer to Appendix F (section 8.5.5, pages 159 to 163 of 207) of Exhibit B-1.

Vegetation, including merchantable timber (both coniferous and deciduous tree species) will be assessed by forestry engineering during the Project detailed design. Timber cruising and cruise compilations will identify the species percent and merchantable volume on both Crown and private lands.

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).

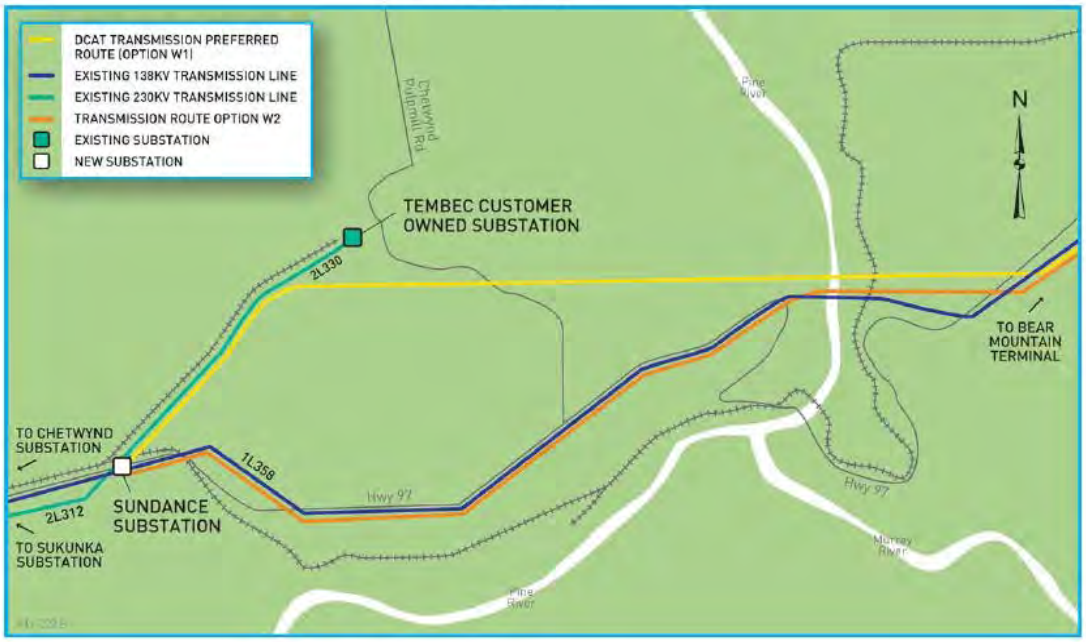
1.29.2 Has BC Hydro determined if any of the cleared trees could be of use to the Tembec mill.

RESPONSE:

Not at this time. Timber cruising, cruise compilations and appraisals will be completed by forestry engineering during the detailed design to determine timber merchantability and suitability for local forest companies.

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

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



1.30.1 Please provide the scale for the transmission route maps.

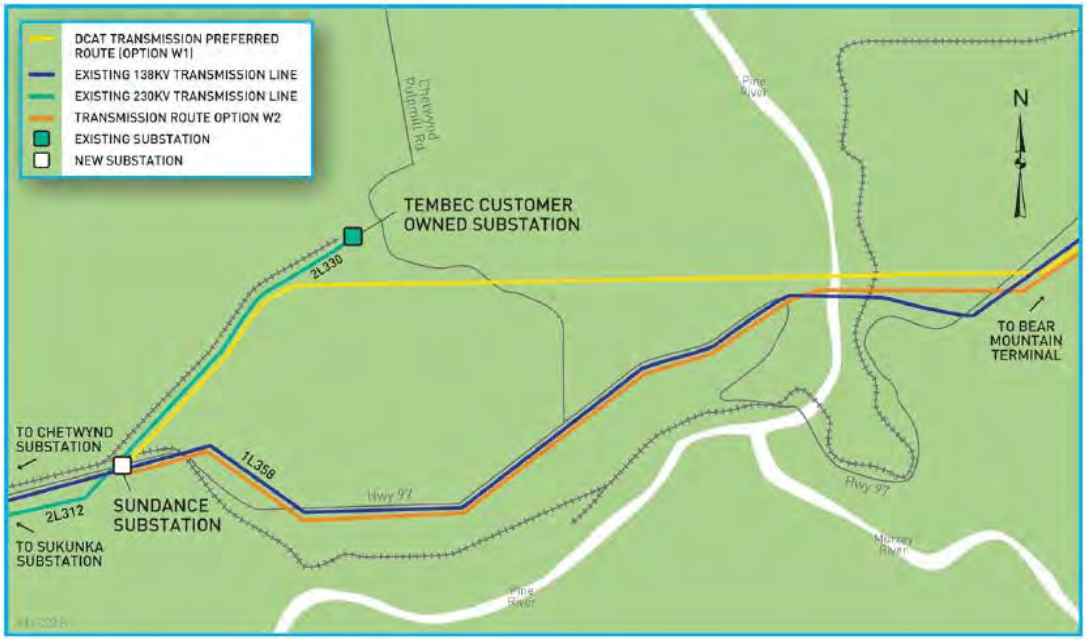
RESPONSE:

The maps included in Chapter 4 of Exhibit B-1 are for illustrative purposes and are not to scale.

Route orthophotos and segment maps that are to scale can be found in Appendix D of Exhibit B-1.

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

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



1.30.2 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.

RESPONSE:

The current location of the Tembec customer site is in the middle of their mill operations. Expanding the station in this location is not feasible, and routing new transmission lines through the existing operations area is not ideal. Because of the active Tembec operations, there are also mill safety requirements that would place unacceptable limitations on BC Hydro's access to the station. Therefore, a new station and separate access would have to be constructed outside of the mill operations area.

The SLS location near Highway 97 offers easier year round access and construction access due to its proximity to the highway. A station closer to the Tembec mill would involve building permanent access from the highway going north, through private

property and over one creek, with potential environmental impacts. It would also need to cross over the CN Rail track.

Further, if the station were to be located adjacent to the Tembec mill operations, additional transmission lines would still be required between the currently proposed SLS location near Highway 97 and the more northern location as follows:

- **The 138 kV line between SLS and CWD would need to be extended north in order to connect to SLS;**

- **A future "2016 stage", while still being studied, potentially requires an additional 230 kV line to connect SLS to SNK. The line length would be longer to reach the more northern site; and**

- **Maintaining a portion of 1L358 to serve customer load (refer to the response to BCUC IR 1.17.3.1) would require 1L358 to be extended to the new more northern station location, or a 138 kV interconnection at the site currently proposed.**

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.

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

RESPONSE:

The salvage value is forecast to be approximately $120,000.

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.

1.31.2 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.

RESPONSE:

BC Hydro has not done a trade-off analysis of salvage value versus the potential to provide 138 kV service over the planning period. At this time, it appears that it will not be necessary to retain 1L362 and portions of 1L358 once the Project is in service.

As discussed at page 4-15 of Exhibit B-1, retaining the lines would result in ongoing operating and maintenance costs (including vegetation management), and would retain a larger system footprint and environmental fragmentation than is necessary. In addition, the existing 138 kV lines are approximately 40 years old and will require a complete structure rebuild within the next 10 to 20 years.

Please also refer to the responses to BCUC IRs 1.17.3, 1.17.3.1, 1.17.6, and 1.17.6.1.

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.

1.31.3 How was the decision to decommission made?

RESPONSE:

The decision to decommission was made based on 1) the 138 kV lines being unnecessary after the DCAT Project is in place; 2) the 138 kV lines are approximately 40 years old and will require complete structure replacements over the next 10 to 20 years; and 3) to minimize impacts on landowners and the environment by reducing fragmentation. Both First Nations and local governments expressed a desire to minimize fragmentation where possible.

Please also refer to the responses to CEC IR 1.31.2 and BCUC IR 1.17.7.

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]

1.32.1 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?

RESPONSE:

The 230/138 kV transformer ensures N-1 reliability to CWD because the loss of this transformer would result in CWD to be served by 1L361 only.

The supply to Groundbirch and Dawson Creek areas is not impacted by the loss of this transformer; however the loss of two 230 kV transmission lines would have an impact on the supply to Groundbirch and Dawson Creek areas. Therefore, the outage of the transformer is not equivalent to taking out 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.

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

RESPONSE:

BC Hydro is not aware of a specific B.C. construction inflation index published by a credible organization such as Stats Canada. Stats Canada does publish a broader based Non-residential Building Construction Price Index, Seven City Composite (CANSIM Table 327-0043). This index includes Vancouver, B.C. Based on this index where 2002 = 100 the last five years is as follows: 2006 = 124.9, 2007 = 136.8, 2008 = 150.8, 2009 = 142.0 and 2010 = 141.5. In BC Hydro's view, this reflects the best information relevant to electric utility industry.

Another Canadian price index, Electric Utility Construction Price Index (CANSIM Table 327-0011) Transmission Line Systems, produced by Stats Canada specifically targets transmission line construction. Based on this index where 1992 = 100 the last five years is as follows: 2006 = 136.2, 2007 = 142.6, 2008 = 148.8, 2009 = 149.7 and 2010 = 151.0.

Based on the flattening trend of these indices, and its internal observations and external consultants, BC Hydro expects construction inflation will not exceed CPI or 2.1 per cent per annum over the next three years.

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

6.1.6.1 Summary of Consultation to Date

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

1.34.1 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?

RESPONSE:

BC Hydro strikes what it believes is an appropriate balance between openness and transparency, canvassing the views of stakeholders and cost effectiveness and efficiency.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.1 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?

RESPONSE:

BC Hydro's discussions with customers who have expressed a preliminary interest, or who are in the study process, indicate load is materializing in both Groundbirch and Dawson Creek areas, sufficient to exceed the capacity of the DCAT Project.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.2 How does the security cover the cost of the Project?

RESPONSE:

The new industrial customers will provide security equal to 60 per cent of the Project cost, or $131.5 million. The security amount is reduced as revenues from the new industrial customers are received. If any portion of the security remains in place 12 years after commencement of service, in accordance with Electric Tariff Supplement No. 6, the remaining security becomes the property of BC Hydro.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.3 Please provide the terms and conditions for the security.

RESPONSE:

BC Hydro will enter into a Security Agreement with customers pursuant to clause 13 of Appendix 1 to the Facilities Agreement (Electric Tariff Supplement No. 6) for costs in the approved form, and the agreed amounts. The general terms and conditions provided in the Security Agreement will include the delivery, holding and release of security.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.4 Is the security released based on customer revenue over time?

RESPONSE:

Yes, the security is released annually by BC Hydro in the amount of customer revenues.

Please also refer to the response to CEC IR 1.35.2.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.5 How much customer revenue does BC Hydro estimate is required to insulate existing customers from unutilized or stranded cost of transmission infrastructure?

RESPONSE:

Customers are providing security for 60 per cent of the expected Project cost, which is calculated to be $131.5 million. The estimated customer revenue fully covers the amount of security in the time periods indicated in responses to BCUC IR 1.48.2 and CEC IR 1.16.2.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.6 Has BC Hydro considered any other mitigations of this risk or has it only considered the security proposal it has adopted?

RESPONSE:

Please refer to the response to BCUC IR 1.45.1.

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

The need for the Project is discussed in Section 2.5. As explained there, some enhancement of the transmission system is required to meet current loads. Thus, there is a high level of confidence that the Project will provide some benefit by enhancing the quality of service to existing customers. However, the Project is also required to serve significant, industrial customer demand. To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers to cover 60 per cent of the costs of the Project. The risk of unused capacity burdening ratepayers in these circumstances is thus low.

1.35.7 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?

RESPONSE:

BC Hydro believes it has appropriately mitigated the risk to customers.

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.

1.36.1 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?

RESPONSE:

Yes, the procurement risks that are expected on this project will be addressed through the application of BC Hydro's normal procurement risk management process.

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.

1.36.2 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?

RESPONSE:

Standard procurement processes and procedures will be used to mitigate procurement risk, as described in sections 7.3.1 and 7.3.2 of Exhibit B-1.

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.

1.36.3 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?

RESPONSE:

The risk management and strategies are described in Exhibit B-1 Chapter 7. The strategies applied to detailed design and construction risk management are, for the most part, ones that BC Hydro typically faces on large transmission projects.

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

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

1.36.4 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?

RESPONSE:

BC Hydro responds to service requests from new customers in accordance with it's Electric Tariff and pursuant to the *Utilities Commission Act.* BC Hydro has an obligation to serve a customer's request for service regardless of industry type and and/or customer's reasoning for requesting service.

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

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

1.36.5 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?

RESPONSE:

BC Hydro's alternative considerations for the Project are described in Exhibit B-1, Chapter 3, pages 3-7 to 3-13 and at Appendix B of Exhibit B-1. Appendix B also includes discussion of dismissed alternatives at pages 62 to 65.

A discussion of preliminary considerations and options for nominal F2016 stage system upgrades are included in Exhibit B-1, Appendix B, pages 94 to 100.

Please also refer to the response to BCUC IR 1.18.4.

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

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

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

RESPONSE:

This is the response to CEC IRs 1.36.6, 1.36.7 and 1.36.8.

Depending on when the CPCN is issued, BC Hydro may need to engage some suppliers and contractors early. If this occurs, BC Hydro will do it in a way to mitigate the cost risk. For example, if any construction contracts are awarded, no physical work will proceed until the CPCN issued. Similarly for large material orders, BC Hydro will try to wait to award any contracts until CPCN approval is received, but if required may award a contract with an appropriate exit clause to minimize cost exposure.

Prior to receiving the CPCN, BC Hydro intends to reach mutually acceptable terms with as many property owners as possible through option agreements. This will enable project construction to begin as soon as possible following anticipated CPCN approval in the spring of 2012. Property owners are being compensated for the option and interim access prior to the approval of CPCN. The option to acquire the right-of-way would be exercised if the Project receives BCUC approval.

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

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

1.36.7 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?

RESPONSE:

Please refer to the response to CEC IR 1.36.6.

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

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

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

RESPONSE:

Please refer to the response CEC IR 1.36.6.

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)

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

RESPONSE:

Please refer to the response to CEC IR 1.9.2.

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)

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

RESPONSE:

Please refer to the response to CEC IR 1.9.2.

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:

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

RESPONSE:

This responds to CEC IRs 1.38.1, 1.38.2, 1.38.3, and 1.38.4.

BC Hydro currently has four gas-fired generation sources in its system: Fort Nelson Generating Station, Island Cogeneration Plant, McMahon Cogeneration Plant, and Burrard Thermal Generating Station (Burrard). Burrard can only be relied upon for emergency service once its capacity contribution to the system has been replaced and is not expected to impact the longer term requirement to generate 93 per cent of the energy from clean resources. For the remainder of these facilities, they make up more than 5 per cent of the generating capability of the system, thus leaving little space for developing additional gas-fired generation while meeting the 93 per cent clean or renewable target set out in the Clean Energy Act (CEA).

The following table sets out the GWhs of generation and the maximum number of MWs of CCGTs or SCGTs that could be developed under a mid load growth scenario while meeting the 93 per cent threshold. These numbers have been calculated using the firm energy capability of system resources ensuring that the 93 per cent target can be maintained even under critical water conditions. SCGTs that are operated as peaking units contribute only a fractional amount of energy to the system and have a much smaller impact on the space available under the 93 per cent clean energy target.

Year	2014	2016	2020	2030
Space remaining for thermal generation (GWh)	700	800	1,000	1,600
MWs of CCGTs that could be built	100	100	150	200
MWs of SCGTs that could be built	500	500	700	1050

In addition to the constraints posed by the minimum clean generation requirements of the CEA, there are also significant development risks associated with acquiring electricity from gas-fired generation. Siting gas-turbines with a nameplate capacity of 50 MW or greater would trigger the B.C. Environmental Assessment Act and gas-fired generation requires an air emission permit pursuant to the B.C. Environmental Management Act, with the public being involved pursuant to the Public Notification Regulation. Emission such as nitrogen oxides, primary and secondary particulate matter, sulphur dioxide and carbon monoxide would be examined, in addition to GHG emissions and provisions for offsetting the GHG emissions. Although GHG emissions are a global as opposed to local impact, BC Hydro's experience has been that local residents are skeptical of the argument that a GHG offset located outside the region or indeed outside B.C. is as effective in reducing GHG emissions.

BC Hydro believes it would take at least four to five years to obtain the permits mentioned above and site a gas-fired generator. Furthermore, BC Hydro must consider how the limited gas potential available under the requirements of the CEA may best serve the interests of its customers. The use of gas must be considered both in terms of expected needs and in terms of contingency plans. BC Hydro is slowly using the last of its large hydro capacity units and must identify future sources of capacity. Gas-fired generation capacity is the default source of capacity should no other clean options be available. Instances where BC Hydro may be able to maximize the benefits of the limited room available for siting gas-fired generation include:

(1) The Fort Nelson region is currently non-integrated and is served by a combination of gas-fired generation and supply from Alberta. Developing additional gas-fired generation to serve load growth may be required if Fort Nelson loads increase and interconnection to the system proves to be prohibitively expensive. In this case, gas fired generation may be the only supply option and could provide significant economic benefits over integrating the region or procuring additional supply from Alberta under most load growth scenarios.

(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.

(3) As part of a Contingency Resource Plan (CRP) to respond to events such as load growth being higher than expected or if DSM yields are lower than expected. Gas-fired generation also remains the only viable, near-term solution that can assist in providing a reliable source of supply to the Lower Mainland/Vancouver Island (LM/VI) region in the event of transmission project delays. The LM/VI region accounts for approximately 70 per cent of BC Hydro system load. Only around 27 per cent of the peak LM/VI load can be met by resources within the region. Developing clean sources of capacity in LM/VI, such as in the form of Pumped Storage facilities, will likely take close to a decade due to construction lead times combined with possible permitting challenges given the fact that a Pumped Storage unit has never been built in Canada. Therefore, finding a location in this region for gas-fired generation remains the only viable, near-term solution that can assist in providing a reliable source of supply to LM/VI in the event of transmission project delays under high load growth/low DSM scenarios. It is not likely that BC Hydro could site gas directly in the LM region, however, there may be some siting options on VI or in the surrounding regions.

The use of gas generation and the interpretation of the 93 per cent clean target, including how it is measured, is an issue that will be addressed in BC Hydro's Integrated Resource Plan (IRP) as directed by the CEA. The IRP is required to be completed by December 3, 2012. Developing gas-fired generation in the Dawson Creek area would add additional generation in a region that is already rich in generation capacity, and would preclude BC Hydro from considering using gas-fired generation in other instances where gas resources may be the only feasible supply option or may provide much larger economic benefits. Using up the limited space available for gas prior to the fulsome IRP evaluation of the role of gas generation would not be in the interest of ratepayers.

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:

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

RESPONSE:

Please refer to the response to CEC IR 1.38.1.

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:

1.38.3 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.

RESPONSE:

Please refer to the response to CEC IR 1.38.1.

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:

1.38.4 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.

RESPONSE:

Please refer to the response to CEC IR 1.38.1.

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

Table 1-2: Near Term Wind Generation Projects

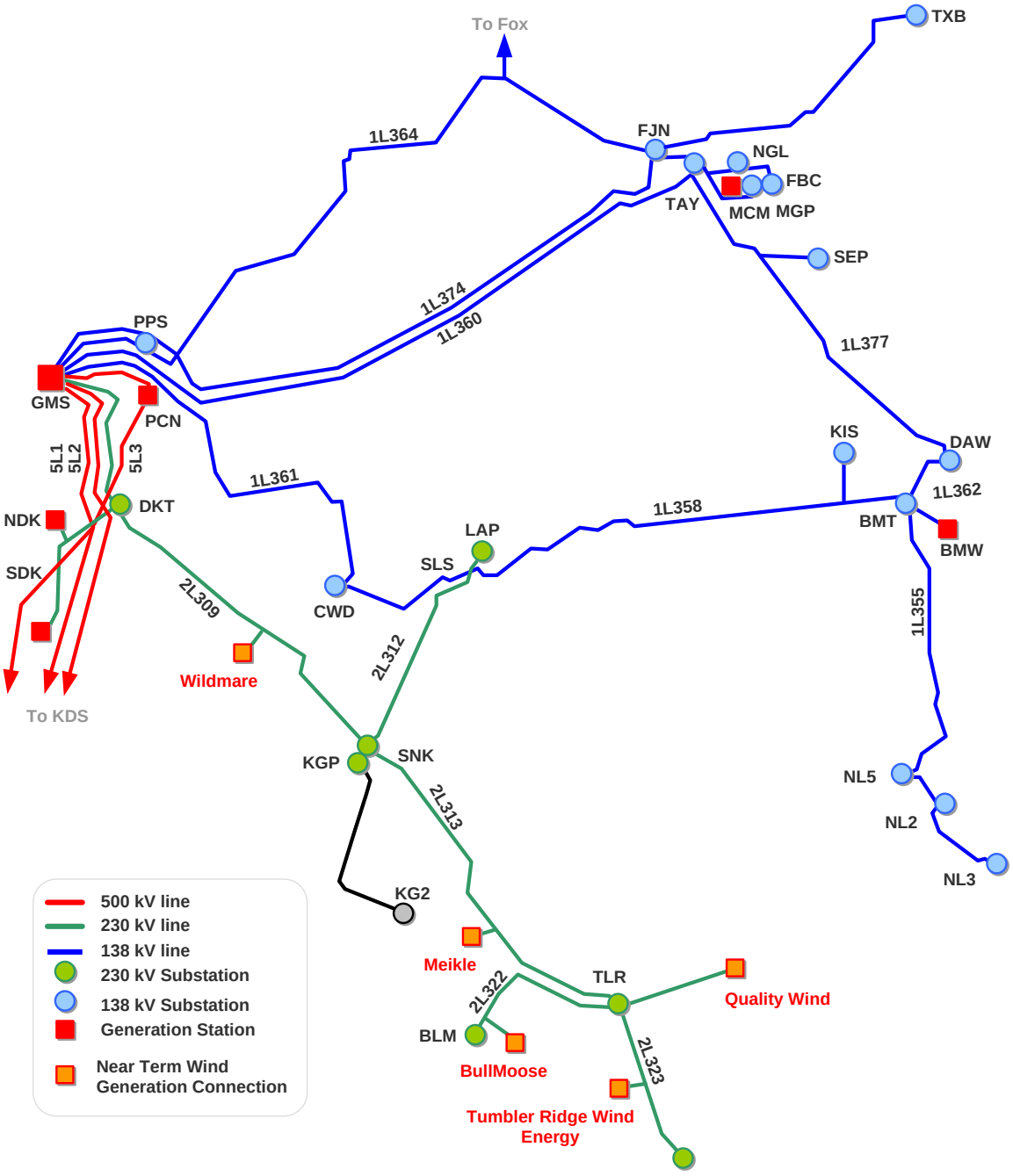
	ISD	MCR (MW)	ELCC (MW)	POI
Wildmare Wind Energy Project	2012	77	16	On 2L309, 17 km north of SNK
Tumbler Ridge Wind Energy Project	2012	47	10	On 2L323, 9 km from TLR
Quality Wind Project	2012	142	33	TLR 230kV bus
Meikle Creek Wind Energy Project	2013	117	25	On 2L313, 23 km north of TLR
Bullmoose Wind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

1.39.1 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.

RESPONSE:

The following figure shows where the Near Term Wind Generation Projects will be connected to the Peace Regional 230 kV system. System upgrades are required to interconnect these wind projects such as line taps, switching stations and telecommunication equipment.

Commercial Energy Consumers Association of British Columbia Information Request No. **1.39.1** Dated: **August 24, 2011** British Columbia Hydro & Power Authority Response issued **September 22, 2011**	Page 2 of 2
British Columbia Hydro & Power Authority **Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission**	**Exhibit: B-6**



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

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	ISD	MCR (MW)	ELCC (MW)	POI
Wildmare Wind Energy Project	2012	77	16	On 2L309, 17 km north of SNK
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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

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

RESPONSE:

Connecting all or any one of these IPP projects to 1L355 would physically require a line from the IPP project to interconnect with 1L355. Additional studies would be required to determine necessary system upgrades. Agreement would also be required with the owner of 1L355 to facilitate interconnection.

Consideration of an alternate point of interconnection would require amendments to EPA's and other related interconnection agreements.

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.

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

RESPONSE:

The anticipated Groundbirch area load is not assumed to be served from the Dawson Creek area. The Groundbirch area load would be connected to the 230 kV system at SLS.

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.

1.40.2 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?

RESPONSE:

Groundbirch loads are expected to materialize in the northern part of the Groundbirch area. The Project provides an interconnection to 2L312 at SLS, which facilitates the most suitable means for serving the load. Viable alternatives which provide sufficient capacity to service load include 230 kV supply from the new SLS, or 230 kV supply from a new substation connected to the 230 kV lines that are part of the Project.

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.

1.40.3 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?

RESPONSE:

Near term wind generation projects do not require significant system upgrades, hence they do not materially affect the interconnection of the Groundbirch loads.

Plans to integrate future wind generation on the Peace Regional 230 kV transmission system may require additional 230 kV lines into the Tumbler Ridge area. These lines would also add additional load carrying capacity which could be interconnected into the Dawson and Groundbirch areas transmission system.

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.

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

RESPONSE:

Load in the Dawson Creek area has grown above the existing transmission firm capacity and at a rate that outpaces the minimum time required to implement permanent system reinforcements and restore the system to N-1 capability, consistent with planning criteria. Accepting new industrial loads as interruptible is a mitigation plan to minimize the reliability impact to the existing system until permanent system reinforcements are 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:

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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.

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

RESPONSE:

If BC Hydro determined that it was not in compliance with TPL-001 and TPL-002 in the future, it would be required to report the non-compliance and provide mitigation plans to the BCUC in accordance with the Compliance Monitoring Program approved by the BCUC Order No. G-123-09.

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:

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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.

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

RESPONSE:

The distribution loads along Alaska Highway, north of Dawson Creek Substation would be transferred to the Fort St. John distribution system. A total of approximately 8 MW of distribution loads from Dawson Creek Substation may be transferred to Fort St-John Substation with 4 MW starting in 2011 and another 4 MW in 2012.

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.

1.41.4 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.

RESPONSE:

BC Hydro cannot add to the information provided in the above reference at (c) as it involves third party confidential information, however, such potential contributions are minimal.

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

1.42.1 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.

RESPONSE:

As noted in Exhibit B-1, Appendix B, page 28 of 100 the point of interconnect (IPO) for some of the new load at the time of the planning study was unknown. For these loads POI were assumed to be connected to the busses shown in Table 4-1 as referenced above.

The following table shows the amount of load assumed supplied by the Point-of-Interconnection (POI) for each of the five regions in Table 4-1. The data reflects the Base Case forecast for F2027 which represents the peak load over the 30-year planning period.

Please note the table below corrects the assumed POI for the Dawson Creek and Groundbirch areas shown in Table 4-1 in the reference above.

	Area	Assumed POI (kV)	F2027 Load at the POI (MW)	Area Aggregate F2027 Load (MW)
1	Dawson Creek Area	BMT 138	64	222
2	Groundbirch Area	SLS 230	137	137
3	Chetwynd Area	CWD 138	12	202
4	Fort St-John/Fox Area	FJN 138	22	234
5	GMS Area	PPS 138	20	20

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.

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

RESPONSE:

The following transmission system upgrades are required to service the Peace Region wind generation projects with approved EPAs. Security is provided for the system upgrades in accordance with BC Hydro's Open Access Transmission Tariff (OATT).

1	**Wildmare Wind Energy**	**230 kV 3-breaker switching station located on 2L309**
2	**Tumbler Ridge Energy**	**230 kV tap on 2L323**
3	**Quality Wind**	**230kV line position at Tumbler Ridge Substation**
4	**Meikle Creek Wind Energy**	**230 kV 3 breaker switching station located on 2L313**
5	**Bullmoose Wind Energy**	**230 kV tap on 2L322**

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.

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

RESPONSE:

Please refer to the response to CEC IR 1.43.1.

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.

1.43.3 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?

RESPONSE:

The extent of transmission system upgrades to integrate additional wind generation in the Peace Region would depend on the generation capacity and location of future wind generation farms. Because of the large potential for wind generation in the South Peace Region in proximity to Tumbler Ridge, a second 230 kV transmission line would likely be required between GMS and TLR as well as upgrading the GMS 500 kV/230 kV transformers with higher capacity units.

BC Hydro notes the Reference should be to Exhibit B-1 Appendix B, page 94.

Hunter Litigation Chambers

HUNTER / BERARDINO / McEWAN / KAARDAL

August 24, 2011 File no: 1531.008

Via E-Mail - commission.secretary@bcuc.com

Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

Re: In the Matter of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 and An Application by British Columbia Hydro and Power Authority ("BC Hydro") for a Certificate of Public Convenience and Necessity ("CPCN") for the Dawson Creek/Chetwynd Area Transmission ("DCAT") Project BCUC Order G-132-11

Further to the Regulatory Timetable attached to Order No. G-132-11 (Exhibit A-1), we enclose for filing with the Commission Information Request No. 1 made to BC Hydro by the Intervener COPE, Local 378.

A copy of the information request in MS Word format will be sent to BC Hydro under separate cover.

Please call if you have any questions or if you require any further information.

Yours truly,

Hunter Litigation Chambers

Per:

Mark S. Oulton
MSO/bb
cc BC Hydro, Attention: Janet Fraser, Chief Regulatory Officer

Registered Interveners

Client

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PRACTICE CONDUCTED THROUGH A PERSONAL LAW CORPORATION

REQUESTOR NAME: **Canadian Office and Professional Employees Union, Local 378 (COPE 378)**

INFORMATION REQUEST ROUND NO: **1**

TO: **BRITISH COLUMBIA HYDRO & POWER AUTHORITY**

DATE: **August 24, 2011**

PROJECT NO. **3698640**

APPLICATION NAME: **CPCN – Dawson Creek/Chetwynd Area Transmission Project**

1.0 Reference: Ex. B-1, Chapter 2, Project Justification

In section 2.3 BC Hydro states that in preparing the DC Area Load Forecast, BC Hydro analyzed potential growth in two areas and prepared two associated forecasts: (a) a Gas Producer Forecast that provides the load forecast for unconventional gas producers; and (b) an Other Forecast which includes all other load including residential, commercial and industrial loads.

In Figure 2-5 BC Hydro sets out the Load Forecast Scenarios showing that the existing capacity in the Dawson Creek and Groundbirch areas cannot serve the entire winter peak load in a N-1 scenario and, starting in 2014, in an N-0 scenario.

1.1 Please prepare a Load Forecast Scenario (similar to Figure 2-5) showing both the Gas Producer Forecast and the Other Forecast.

1.2 Please advise as to when the capacity of the existing system would be exceeded in an N-1 and an N-0 scenario for each of the Other Forecast and the Gas Producer Forecast.

2.0 Reference: Ex. B-1, Chapter 5, Section 5.1, Table 5-1

2.1 Please advise whether BC Hydro intends to implement any of the mitigation measures identified in Table 5-1 and, if so, identify which measures will be implemented, the associated cost and confirm whether these costs are included in the Project Costs discussed in section 4.7 of Exhibit B-1.

3.0 Reference: Ex. B-1, Chapter 2, Section 2.7, pgs 2-18 to 2-19
Chapter 7, Section 7.3, pgs. 7-2 to 7-5

BC Hydro states that the risk of 60 percent of the cost of the Project will be borne by the new customers (Gas Producers) for whom the project is being built and that the exposure of existing customers to the remaining 40 percent of Project costs would be addressed by BC Hydro's "robust cost risk management programs". These risk management programs fall into two categories, risks associated with procurement issues and design/construction risks.

In the Review of BC Hydro Report dated June 2011 (a copy of which is appended as Appendix 1 to these Information Requests), the Review Panel raises concerns

regarding the labour intensive and inconsistent nature of BC Hydro's existing procurement processes. The Panel makes recommendations to potentially reduce BC Hydro's procurement costs (see, for example, pgs 59, 63 and 68 of Appendix 1).

At pgs 66 and 67 of Appendix 1, the Panel raises specific concerns with how BC Hydro manages the cost risks in the procurement process and makes specific recommendations regarding mitigating or limiting these risks (see. Pg 68).

At pages 72 and 73 of Appendix 1, the Review Panel notes that BC Hydro needs to improve their risk management, procurement management and project budgeting to provide

3.1 Please advise whether BC Hydro has or intends to take any steps to implement the recommendations of the Review Panel in the context of this project.

3.2 If so, please

3.2.1 identify what steps or measures will be taken by BC Hydro in this Project; and

3.2.2 the estimated impact, if any, of these measures on the overall cost or cost risk of the Project to ratepayers.

3.3 If not, please explain why not.

Appendix 1 to Information Request 3.0

Review of BC Hydro
June 2011

1.0 Reference: Ex. B-1, Chapter 2, Project Justification

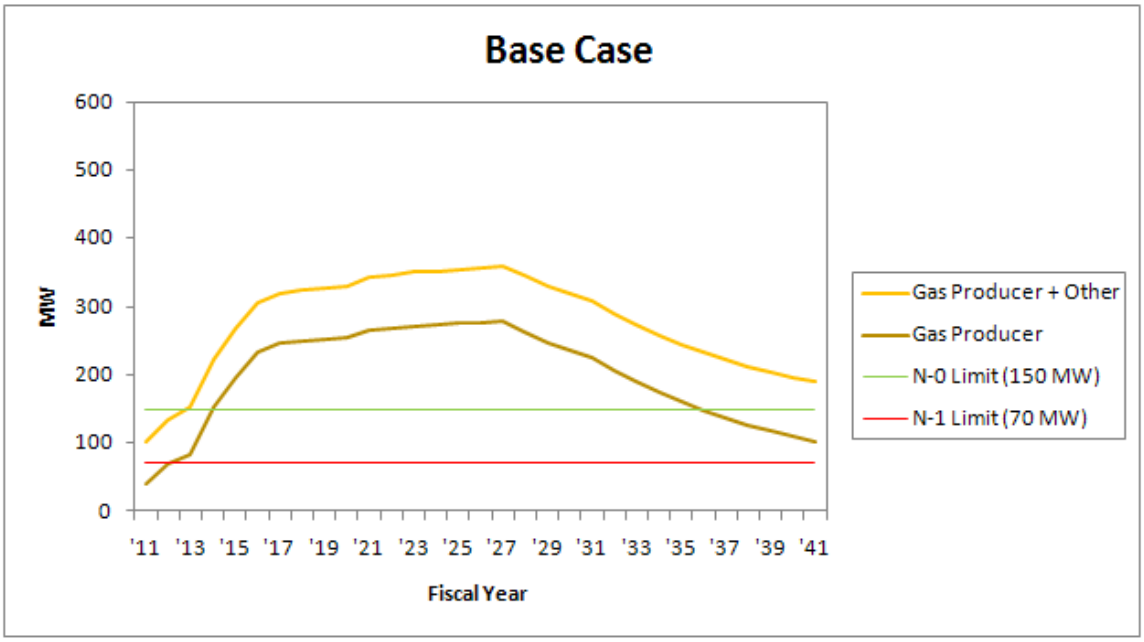
In section 2.3 BC Hydro states that in preparing the DC Area Load Forecast, BC Hydro analyzed potential growth in two areas and prepared two associated forecasts: (a) a Gas Producer Forecast that provides the load forecast for unconventional gas producers; and (b) an Other Forecast which includes all other load including residential, commercial and industrial loads.

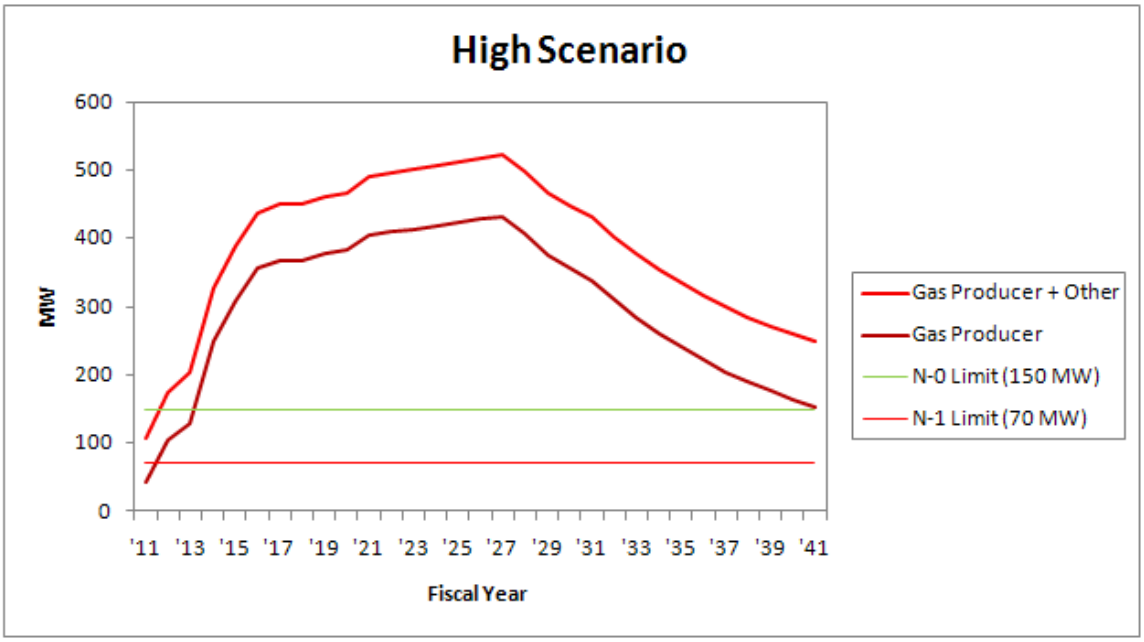
In Figure 2-5 BC Hydro sets out the Load Forecast Scenarios showing that the existing capacity in the Dawson Creek and Groundbirch areas cannot serve the entire winter peak load in a N-1 scenario and, starting in 2014, in an N-0 scenario.

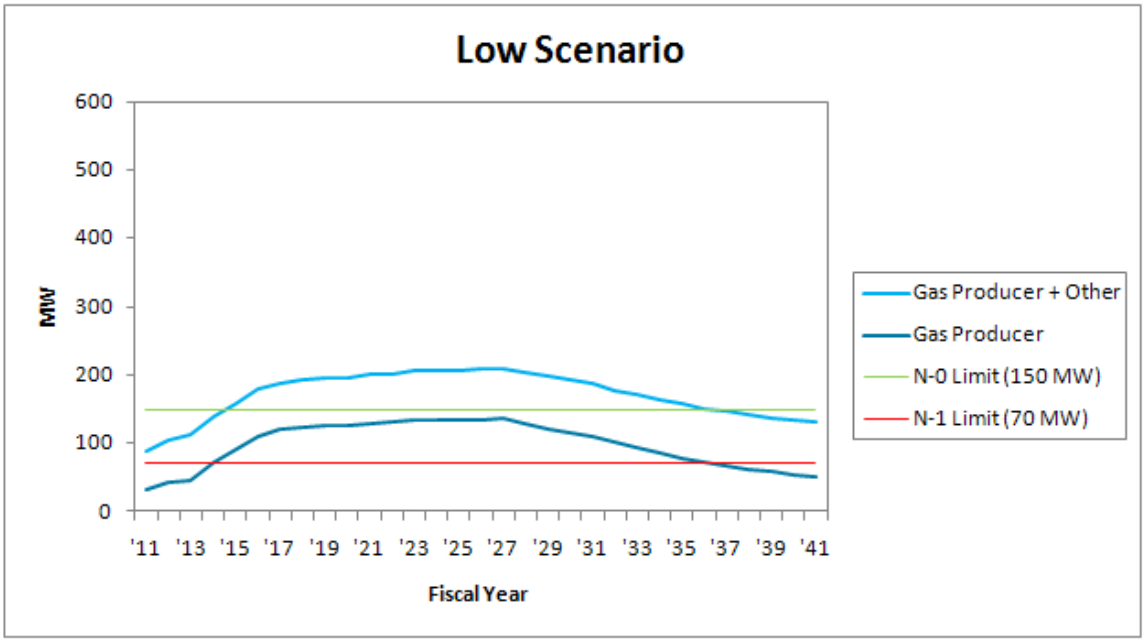
1.1.1 Please prepare a Load Forecast Scenario (similar to Figure 2-5) showing both the Gas Producer Forecast and the Other Forecast.

RESPONSE:

The figures below show Gas Producer and Other Forecast for Base Case, High and Low Case.




High Scenario
600
500
400
300
200
100
0
MW
'11 '13 '15 '17 '19 '21 '23 '25 '27 '29 '31 '33 '35 '37 '39 '41
Fiscal Year
Gas Producer + Other
Gas Producer
N-0 Limit (150 MW)
N-1 Limit (70 MW)


Low Scenario
600
500
400
300
200
100
0
MW
'11 '13 '15 '17 '19 '21 '23 '25 '27 '29 '31 '33 '35 '37 '39 '41
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Gas Producer + Other
Gas Producer
N-0 Limit (150 MW)
N-1 Limit (70 MW)

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In Figure 2-5 BC Hydro sets out the Load Forecast Scenarios showing that the existing capacity in the Dawson Creek and Groundbirch areas cannot serve the entire winter peak load in a N-1 scenario and, starting in 2014, in an N-0 scenario.

1.1.2 Please advise as to when the capacity of the existing system would be exceeded in an N-1 and an N-0 scenario for each of the Other Forecast and the Gas Producer Forecast.

RESPONSE:

Figure 2-5 on page 2-14 of Exhibit B-1 shows the existing system N-1 and N-0 limits for the load forecast scenarios. The individual Other Forecast and Gas Producer Forecast are cumulative and cannot be used to indicate N-1 and N-0 limits because elements of the existing load are distributed in both forecasts (i.e., existing gas producers in Gas Producer Forecast and existing other load in the Other Forecast).

2.0 Reference: Ex. B-1, Chapter 5, Section 5.1, Table 5-1

1.2.1 Please advise whether BC Hydro intends to implement any of the mitigation measures identified in Table 5-1 and, if so, identify which measures will be implemented, the associated cost and confirm whether these costs are included in the Project Costs discussed in section 4.7 of Exhibit B-1.

RESPONSE:

Please refer to the response to BCOAPO IR 1.11.1.

3.0 Reference: Ex. B-1, Chapter 2, Section 2.7, pgs 2-18 to 2-19
Chapter 7, Section 7.3, pgs. 7-2 to 7-5

BC Hydro states that the risk of 60 percent of the cost of the Project will be borne by the new customers (Gas Producers) for whom the project is being built and that the exposure of existing customers to the remaining 40 percent of Project costs would be addressed by BC Hydro's "robust cost risk management programs". These risk management programs fall into two categories, risks associated with procurement issues and design/construction risks.

In the Review of BC Hydro Report dated June 2011 (a copy of which is appended as Appendix 1 to these Information Requests), the Review Panel raises concerns regarding the labour intensive and inconsistent nature of BC Hydro's existing procurement processes. The Panel makes recommendations to potentially reduce BC Hydro's procurement costs (see, for example, pgs 59, 63 and 68 of Appendix 1).
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At pages 72 and 73 of Appendix 1, the Review Panel notes that BC Hydro needs to improve their risk management, procurement management and project budgeting to provide

1.3.1 Please advise whether BC Hydro has or intends to take any steps to implement the recommendations of the Review Panel in the context of this project.

RESPONSE:

BC Hydro is still reviewing the potential impacts of the Government Review as a whole. However, at this time, BC Hydro is of the view that the Government Review does not have an impact on the Project in terms of timing, cost or rate impacts.

Please also refer to the responses to BCUC IRs 1.57.3 and 1.58.4.

3.0 Reference: Ex. B-1, Chapter 2, Section 2.7, pgs 2-18 to 2-19
Chapter 7, Section 7.3, pgs. 7-2 to 7-5

BC Hydro states that the risk of 60 percent of the cost of the Project will be borne by the new customers (Gas Producers) for whom the project is being built and that the exposure of existing customers to the remaining 40 percent of Project costs would be addressed by BC Hydro's "robust cost risk management programs". These risk management programs fall into two categories, risks associated with procurement issues and design/construction risks.

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At pages 72 and 73 of Appendix 1, the Review Panel notes that BC Hydro needs to improve their risk management, procurement management and project budgeting to provide

1.3.2 If so, please

1.3.2.1 identify what steps or measures will be taken by BC Hydro in this Project; and

RESPONSE:

Please refer to the response to COPE IR 1.3.1.

3.0 Reference: Ex. B-1, Chapter 2, Section 2.7, pgs 2-18 to 2-19
Chapter 7, Section 7.3, pgs. 7-2 to 7-5

BC Hydro states that the risk of 60 percent of the cost of the Project will be borne by the new customers (Gas Producers) for whom the project is being built and that the exposure of existing customers to the remaining 40 percent of Project costs would be addressed by BC Hydro's "robust cost risk management programs". These risk management programs fall into two categories, risks associated with procurement issues and design/construction risks.

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At pages 72 and 73 of Appendix 1, the Review Panel notes that BC Hydro needs to improve their risk management, procurement management and project budgeting to provide

1.3.2 If so, please

1.3.2.2 the estimated impact, if any, of these measures on the overall cost or cost risk of the Project to ratepayers.

RESPONSE:

Please refer to the response to COPE IR 1.3.1.

3.0 Reference: Ex. B-1, Chapter 2, Section 2.7, pgs 2-18 to 2-19
Chapter 7, Section 7.3, pgs. 7-2 to 7-5

BC Hydro states that the risk of 60 percent of the cost of the Project will be borne by the new customers (Gas Producers) for whom the project is being built and that the exposure of existing customers to the remaining 40 percent of Project costs would be addressed by BC Hydro's "robust cost risk management programs". These risk management programs fall into two categories, risks associated with procurement issues and design/construction risks.

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At pages 72 and 73 of Appendix 1, the Review Panel notes that BC Hydro needs to improve their risk management, procurement management and project budgeting to provide

1.3.3 If not, please explain why not.

RESPONSE:

Please refer to the response to COPE IR 1.3.1.

PROJECT NO: 3698640

BRITISH COLUMBIA UTILITIES COMMISSION

Certificate of Public Convenience and Necessity for the Dawson Creek/Chetwynd Area Transmission Project

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INFORMATION REQUESTS ROUND 1

DATED AUGUST 24, 2011

SUBMITTED BY:

Counsel for West Moberly First Nations

RANA LAW
Barristers & Solicitors
Attn.: Allisun Rana
#102 – 620, 12th Avenue S.W.
Calgary, AB T2R 0H5
Tel. 403-455-3673
Fax 403-452-9803

Information Requests – BC Hydro's DCAT CPCN application

REQUESTOR NAME: West Moberly First Nation
INFORMATION REQUEST ROUND NO: 1
TO: British Columbia Hydro and Power Authority (BC Hydro or the developer)
DATE: August 24, 2011
PROJECT NO: 3698640
APPLICATION NAME: Dawson Creek/Chetwynd Area Transmission Project (DCAT)

NOTE: In several places, the WMFN refers to IR's issued August 17, 2011, by the BCUC to the developer. In these cases the WMFN IR is in addition to, but does not replicate, that previous IR.

1.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 6, First Nations Consultation and Public Engagement
Free, Prior, and Informed Consent
NOTE: The WMFN suggests this IR is in addition to the BCUC IR #15.1.

No discussion is provided in the developer's Application documents (B-1, especially but not limited to, in Chapter 6) on the issue of free, prior and informed consent. Documentation of free, prior and informed consent (FPIC) of indigenous peoples to development on indigenous lands, and particularly Treaty lands where a clear relationship exists between First Nations and the Crown, is a fundamental concept of the International Declaration on the Rights of Indigenous Peoples, to which Canada is a signatory.

1.1. Explain what measures were taken by BC Hydro to achieve and document FPIC of WMFN to the DCAT Project.
1.2. If any measures were taken, how were WMFN and other indigenous groups involved in evaluating the success of BC Hydro in meeting FPIC objectives?
1.3. Has BC Hydro received a statement of FPIC in relation to the DCAT project from any potentially affected Aboriginal group?
1.4. If FPIC has not been adequately achieved and documented, how has BC Hydro accounted for the increased risk created by the absence of FPIC specific to the Project?

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

"First Nations have been consulted with respect to the Project as detailed in section 6.1 of this application. As with general public engagement, no significant issues were raised with respect to the Alternatives."

2.1 Please identify if, how, and in what amount did BC Hydro provided funding to WMFN in order to support due consideration of DCAT alternatives and design by WMFN, to consider the potential of various alternatives to impact the rights, interests and uses of WMFN, and to provide feedback designed to inform BC Hydro decisions regarding alternatives.

2.2 Please advise how the developer came to a conclusion that it had chosen the appropriate routing alternatives, and that the project is unlikely to cause significant adverse impacts on any VEC or VSC, in the absence of traditional land use (TLU) and traditional knowledge (TK) from WMFN, a primary land user and Treaty and Aboriginal rights holder in the area.

2.3 Please indicate what methods, thresholds or measures BC Hydro used to determine what issues raised by First Nations with respect to the Alternatives were of significance and what issues were not.

2.4 Please identify whether input from WMFN was sought in determining criteria, thresholds of acceptable change, or other metrics used to assess "significance" of issues and potential project outcomes.

Exhibit B-1, Chapter 4, Section 4.3.2.1 – p. 11
"A number of sub-options have been identified to route away from homes, where possible, and to minimize potential conflicts with pipeline infrastructure. BC Hydro will continue to evaluate these sub-options in the detailed design to confirm the specific routing in those areas."

2.6 Should the project be permitted and proceed, please identify how future WMFN input in micro-route changes will be incorporated into final project routing plans, and when.

3.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 3, Section 3.3, pp. 7 and 8
Criteria Used to Assess Alternative Line Routes and Infrastructure Locations

"In addition to financial considerations, BC Hydro also considered externalities such as reliability outcomes of the proposed alternatives, environmental, First Nation and social considerations in its planning level decision-making process in identifying a preferred alternative."

3.1 Please clarify what "First Nation…considerations" were used in planning level decision-making processes in identifying preferred alternatives.
3.2 Please indicate if and how Aboriginal and Treaty rights "considerations" specific to WMFN were included in the criteria used to assess the alternative line routes and other project component alternatives.
3.3 Please identify any weighting used for different criteria in assessment of project and routing/siting alternatives, how this weighting was determined, and whether any WMFN representatives were involved in either the determination of appropriate criteria or determination of appropriate criteria weighting.
3.4 Please provide a table listing all instances where input from WMFN representatives has led to project routing alterations, or any other project planning changes for the proposed DCAT project, including the source(s) of the information that led to the project alteration.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

"In addition to the technical evaluation of alternatives, a number of other considerations may impact selection of a preferred alternative for the Project. These considerations may include environmental review, First Nation consultation and public input. Specifically with respect to this project, as Alternative 1 and 2 generally require substantially similar land use in the same areas such considerations did not materially impact choice of a preferred alternative. "

4.1 Please identify how it was determined that WMFN land use for practicing Treaty and Aboriginal rights in the areas covered by Alternatives 1 and 2 were "substantially similar", including what traditional or current land use studies or other sources were used to make this determination.
4.2 If no WMFN traditional and current land use studies related to the proposed development have been incorporated into the project assessment, please indicate how BC Hydro was able to determine that "First Nation consultation… considerations" should not "materially impact" on alternatives assessments.
4.3 Will the WMFN be provided further opportunities to provide meaningful input into alternatives consideration, routing of the transmission line, siting of project components, and micro-routing decisions during detailed project planning? If so, please provide details on the methods BC Hydro will use to engage the WMFN in detailed project planning and siting determinations.

Exhibit B-1, Chapter 4, Section 4.3.2.1, pp. 4-7, 4-8

"The route evaluation is based on a number of objectives, which include minimizing potential impacts to the environment, private landowners, First Nation interests, archaeological sites, project cost, reducing project construction and schedule risk, and maximizing maintainability. Criteria were developed against these objectives; they include construction cost, length of line and number of poles, constructability and access, potential impact on wildlife and riparian habitat, amount of private and Crown land, existing dwellings located near the line, First Nations consultation, and archaeological potential or location of known archaeological sites. The route options within each segment were evaluated against these criteria.

4.4 It is not clear what the "First Nations consultation" criteria referred to above is composed of. Please clarify.

Exhibit B-1, Chapter 4, Section 4.3.2.1, p. 4-9

"Option E1 was selected as the preferred route for the east segment of the transmission line. Option E1 has a lower impact on private property owners but a higher constructability risk as compared to Option E2 and Option E3. On balance these differences in the criteria used to compare the three options did not identify an option that was superior to the other two options and therefore Option E1 has been selected since it is the lowest cost."

4.5 The discussion noted above makes it appear that alternative routing alignments were determined on the basis of two criteria – impact on property owners and constructability risk. Please clarify whether and how "First Nations consultation" criteria was used in assessment of routing alternatives.

5.0 First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

5.1 Please clarify if and how WMFN members were involved in the collection of TLU and TK information that was integrated into the developer's Application and supporting documents.

5.2 Please identify how much funding was provided to the WMFN to support documentation of baseline cultural and environmental information, and associated assessment in a manner that contributes to the assessment.

5.3 Please identify whether BC Hydro is of the view that the funding it has provided has been adequate and provided within a reasonable timeline to support WMFN involvement, including but not limited to:

5.3.1 Determination of relevant, culturally appropriate Valued Ecosystem Components (VECs) and Valued Social Components (VSCs).

5.3.2 Collection of relevant cultural and environmental baseline data, for VECs/VSCs.

5.3.3 The assessment of Alternatives.

5.3.4 Significance estimations and input regarding determination of appropriate mitigation.

5.4 Please identify what actual concrete information the developer and its consultants collected on the value of areas proximate to the proposed development for TLU and historical values associated with the areas by WMFN members?

5.5 Please clarify any remaining hurdles to incorporation of appropriate WMFN TLU/TK into the currently planned BCUC regulatory timelines, how the developer plans to overcome them, and what effect on the reliability of impact predictions the lack of this information would have on the process.

6.0 First Nations Consultation and Accommodation
Exhibit B-1; Chapter 2, Section 2.3
Consistency of Load Forecast with Treaty and Aboriginal Rights

The need for the DCAT project is based on a load forecast that anticipates rapid industrial growth of the Montney shale gas fields.

6.1 How has BC Hydro confirmed that the level and pace of growth anticipated for the Montney shale gas fields is consistent with the current and future practice of WMFN rights associated with Treaty No. 8 and with S. 35 of the *Constitution Act, 1982*?
6.2 If BC Hydro has not confirmed this, how has BC Hydro accounted for associated risks?

7.0 Reference: First Nation Consultation Summary
Exhibit B-1; Chapter 6, Section 6.1.6.1, p.17
Adequacy and accuracy of BC Hydro's description of consultation with the WMFN to date
NOTE: Related to and building on BCUC IR #9

"West Moberly First Nation asked questions related to BC Hydro's plans for river crossings and for utilizing the existing ROW, and identified concerns related to potential impacts to wildlife (fragmentation, wildlife corridors, and a wetland area used by moose). BC Hydro responded that route investigations were beginning, with a view to running parallel to existing transmission lines where possible, that an environmental overview assessment would be undertaken, and that BC Hydro was looking into removing some of the existing transmission lines after the new ones were in service. West Moberly First Nation indicated that they would also want to review the environmental overview assessment results."

A preliminary review of BC Hydro's "summary of consultation to date" raises troubling inconsistencies between the perspectives of the relationship as described by BC Hydro versus that of WMFN. The consultation record provided by BC Hydro does not accurately and completely reflect the issues that have been raised to this point, and in addition it downplays the lack of meaningful and timely funding and support from BC Hydro for required involvement of WMFN in cultural and environmental studies, including impact assessments requested by WMFN.

7.1 Please provide a revised and updated "summary of consultation", providing further details on the content of all correspondence, communications and meetings between representatives of WMFN and the developer and its representatives in relation to this file, from inception to present.
7.2 There doesn't appear to be any plain language summary of the application, making it difficult for WMFN representatives to review the documentation and seek feedback from WMFN members on this application. Please provide a plain language summary of the Application materials for review by WMFN with its membership.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

WMFN notes that at numerous places in the Application and supporting documents, reference is made to VECs and VSCs. These valued elements of the human and biophysical environments are used to guide environmental impact assessments of all scope and scale; they are effectively the foundation upon which baseline data collection, project-related impact estimation, identification of appropriate mitigation measures, and determinations of residual impact significance are based.

WMFN notes that the Application and supporting documents make no reference to any VECs or VSCs related to First Nations use and occupancy in the potentially affected area. For example, at Section 5.6.4, discussion of Trapping, Hunting and Recreational Fishing identifies no Aboriginal rights, interests or values whatsoever. Also, at page 5-9 of Chapter 5, #20 and #21, Table 5-1, while Land and Resource Use and Recreation are identified as VEC/VSC categories, Aboriginal traditional land use is not. 15 specific mitigations are identified for non-Aboriginal land and resource use impacts while Aboriginal traditional land use is not even recognized as a valued component.

As BC Hydro is aware, Aboriginal and Treaty rights, including but not limited to harvesting of resources in our traditional territories, are protected under s.35 of the *Constitution Act, 1982.* The absence of VEC/VSCs recognizing this central consideration is an unacceptable oversight by BC Hydro.

8.1 Please provide a description of all methods used by the developer and its consultants to identify the VECs and VSCs most important to WMFN during the course of the EOA. ?

8.2 It does not appear from the Application that traditional land use, or other practices associated with Aboriginal and Treaty rights, have been identified as a VEC/VSC. What is the justification for the exclusion of this VEC/VSC? Was WMFN involved in the decision to exclude this VEC/VSC?

8.3 Given the importance of Aboriginal and Treaty rights and associated land use by Aboriginal people, please identify how, in the absence of information on WMFN TLU and TK, BC Hydro can provide assurances to the BCUC and Interveners that its estimation of potential project effects is based on sufficiently credible and comprehensive information.

Appendix F (at page 37 of 207) refers to the AMEC EOA as making a determination on a VEC or VSC-specific basis of whether the project may cause impacts that are: a) adverse; b) significant; and c) likely.

8.4 Please identify:

8.4.1 Why no estimation of the confidence held in each prediction is included; and

8.4.2 How such a determination can be made for any WMFN traditional use VEC/VSC in the absence of actual studies to establish value and use of the area in question by the WMFN?

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

8.5 Please clarify how criteria (g) was utilized in VEC/VSC determination for vegetation and soils.

8.6 Please clarify whether and how criteria (g) was used in the determination of other VECs/VSCs for:
8.6.1 Wildlife
8.6.2 Aquatic resources (water quality and quantity, fish)
8.6.3 Traditional and current Aboriginal land use

8.7 Please clarify:
8.7.1 Whether and how the WMFN was consulted in the determination of what constitutes a "species or ecosystem of cultural, social, and / or economic importance"; and
8.7.2 How determinations were made by BC Hydro and its consultants of what constitutes a "species or ecosystem of cultural, social, and / or economic importance".

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately-owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

9.1 Please identify all methods used by the developer and its consultants to understand historic and current values of the WMFN associated with use of, and occupancy within, the area proposed for the DCAT project.

9.2 Please identify all information collected by the developer and its consultants specific to WMFN land use and occupancy in the transmission corridor and its surroundings, including sources of this information.

9.3 Please identify all of the previous TLU/TK reports or other archival materials used to determine WMFN land use and occupancy in the study area for the proposed DCAT.

9.4Please indicate what specific meaningful traditional and current land use and occupancy information BC Hydro has received through consultation with WMFN and how BC Hydro has made changes to the Project, or otherwise responded, to the provision of information regarding current or planned practice of rights, interests and use by WMFN.

9.5 Does BC Hydro have access to information regarding WMFN land use and rights practice that can confirm the extent to which WMFN members currently use private lands in the area of DCAT for hunting, collection of materials, and other rights based practices?

9.6 Does BC Hydro have access to information regarding the extent to which private lands provide important habitat or corridors for resources or animals, including moose, caribou, fish, birds and other species, upon which WMFN land use and rights, on both Crown and private lands, depend?

9.7 Please identify what efforts BC Hydro will make moving forward to gather meaningful traditional and current WMFN land use and occupancy information and the expected timelines and costs associated with this information collection.

10.0 Reference: Adequacy of Consultation
Exhibit B-1, Chapter 6, Section 6.1.7, p. 25
Adequacy of Consultation
NOTE: Related to BCUC IR#13, specific to WMFN

"BC Hydro has concluded that the consultation and, where appropriate, accommodation undertaken in connection with the Project has been adequate to support its decision to file this application for a CPCN. The information obtained from the consultation process has permitted BC Hydro to make its decision honourably, having regard to the Crown's obligation to Aboriginal people."

10.1 Please identify whether, and if so, why, the developer feels enough information has been collected to date to properly describe WMFN land use in the study area for the purposes of providing the BCUC adequate information upon which to base its decision-making, and to constitute an information base upon which Crown consultation with WMFN can be meaningfully conducted.

11.0 Reference: Study Area(s)
Exhibit B-1, Appendix F, p. 41 of 207
Determination of Appropriate Local and Regional Study Areas

No consistent description of local and regional study areas is provided in the Application documents. For example, the EOA refers to Regional and Local Study Areas at page 41 of 207, but then does not use these geographic scopes consistently throughout Appendix F. This lack of consistency makes it extremely difficult to determine the adequacy or accuracy of baseline data collection, let alone the estimation of project effects.

11.1 Please identify what study area(s) the developer has used or proposes to use for the purposes of collecting baseline information and estimating impacts of the proposed DCAT project on WMFN land use and occupancy, including meaningful exercise of Aboriginal and Treaty rights.
11.2 Please identify the buffers BC Hydro has used around the immediate project footprint for the assessment of other disturbances (e.g. sensory – sight, smell) for each VEC/VSC identified.
11.3 Please identify the study areas (local and regional) used for any TLU/TK work used to inform the project planning to this point.

12.0 Reference: Potential Impacts on Aboriginal and Treaty Rights

12.1 Please clarify the total area likely to be physically disturbed by construction and operations activities along the entire route, for all alternatives, and including access points, temporary work sites, linear developments and substations. Then, for the preferred alternative, identify any plans, policies or programs the developer commits to in relation to minimizing net loss of meaningful use of traditional harvesting territory utilized or potentially utilized by area First Nations, as protected under s.35 of the *Constitution Act, 1982*.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

13.1 Are there any studies on impact of the lines and right of way openings themselves on large mammals in terms of population health, movement and avoidance patterns, disturbance range, and predation effects that have been considered by the developer in it is project planning?

13.2 Was WMFN consulted about wildlife distribution, population health, movements, and potential increased risks on wildlife from the proposed development?

13.3 Has any WMFN Traditional Ecological Knowledge been incorporated into the assessment of potential project effects on wildlife and if not, why?

13.4 If hunting is going to be prohibited during construction:

13.4.1 Under what authority will the restriction be in place, over what area, applying to whom, and for which species?

13.4.2 How will WFMN hunting practices in the area be affected and accommodated through the construction phase?

13.4.3 How will WMFN travels on the land in the area be affected during and after construction?

13.4.4 How will WMFN access to harvesting and other use areas proximate to the proposed DCAT project be protected throughout the life of the project?

14.0 Reference: Baseline Information and Impacts on Wildlife – Species at Risk Exhibit B-1, Appendix F

14.1 How was WMFN traditional knowledge used to inform the gap analysis for endangered species and to identify potential habitats and historical distributions?
14.2 Has the proponent worked with WMFN to determine whether other endangered species, and particularly caribou, were historically present in the study area?
14.3 Linear features continue to be a factor in caribou declines in BC. In light of the recent BC Court of Appeal finding in *West Moberly First Nations v. British Columbia (Chief Inspector of Mines)*, 2011 BCCA 247, regarding caribou recovery in the region, and given the recent efforts on behalf of the WMFN to ensure protection of current and potential caribou habitat in the region, how has the proponent worked with First Nations and the caribou recovery teams to address the risk of impacts from the Project (ie. linear development) and subsequent shale gas development on potential caribou recovery in the region?

15.0 Reference: General Mitigation Issues
Exhibit B-1, Appendix F, p. 58 of 207
Summary of Mitigation Commitments and Role of WMFN in their Identification

Table 4.9 at page 58 of 207 of Appendix F is one of a series of summary tables in Appendix F that identify "available mitigation strategies" that could be used to avoid, minimize or otherwise mitigate potential project effects. What is not clear to the reader is the degree to which each mitigation strategy has actually been adopted by the developer based on its consultants recommendations, and what mitigation strategies and specific measures the EMP and the contractor-specific EPP's will be required to adopt.

15.1 Please provide a summary table listing all mitigation measures, by topic, that BC Hydro commits to adopting for this project, including a reference to where in the Application the commitment is made to adopt the recommended mitigation; and

15.2 Please provide BC Hydro's plans for vetting the Environmental Management Plan and/or contractor-specific Environmental Protection Plans with affected First Nations, including WMFN.

15.3 Please provide a table listing all instances where consideration of WMFN use and/or ecological knowledge has contributed to mitigation commitments made by the developer for the proposed DCAT project, including the source(s) of the information by Aboriginal group, that led to the commitment.

16.0 Archaeological Resources
Exhibit B-1, Chapter 5, Section 5.7
Involvement of WMFN in Archaeological Methods Development and Work

16.1 Please indicate:

16.1.1 What parameters were used in the AOA to determine low, moderate and high archaeological potential; and

16.1.2 How these parameters were informed by WMFN cultural knowledge (current use, trail information, etc.).

16.2Please provide additional information regarding the 'cultural depression' and 'cairn' features reported, and indicate how WMFN was involved in interpreting the potential significance of these features.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

Also, Exhibit B-1, Chapter 5, Section 5.8, p. 24

"Generally, BC Hydro's Environmental Officer will be responsible for: (a) Ensuring the further field investigations are conducted, as necessary before construction occurs; (b) Assessing the effectiveness of mitigation measures; (c) Collecting data to confirm mitigation effectiveness; (d) Ensuring compliance with all environmental permits, notifications and approvals; and (e) Halting work if construction activities are contributing to unacceptable environmental impacts."

The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

17.1 What binding assurances can the developer give WMFN and the BCUC that any gaps in information and mitigation during regulatory would actually be filled "post-regulatory", such that WMFN concerns will be substantively and meaningfully addressed?

17.2The Application materials refer to an Environmental Management Plan (e.g. in the excerpt above and at Appendix F, Section 2.2.3) and to on-site monitoring. No reference is made to the role of area First Nations in development of same, on-the-ground presence, reporting, or involvement in implementation of management plans. Please clarify:

17.2.1 BCH's intent and commitments to having potentially-affected First Nations involved in these stewardship activities on their traditional territories?
17.2.2What commitments the developer has made to including First Nations in the development of EMPs.

17.3 Please identify any commitments by the developer to include WMFN and its members in the management and monitoring of the project during construction, post-construction and operations.

17.4 Please provide a description of all mechanisms by which the developer will seek to resolve any concerns raised by WMFN in relation to the project, through all phases of the Project life cycle, starting with the current regulatory phase.

1.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 6, First Nations Consultation and Public Engagement
Free, Prior, and Informed Consent
NOTE: The WMFN suggests this IR is in addition to the BCUC IR #15.1.

No discussion is provided in the developer's Application documents (B-1, especially but not limited to, in Chapter 6) on the issue of free, prior and informed consent. Documentation of free, prior and informed consent (FPIC) of indigenous peoples to development on indigenous lands, and particularly Treaty lands where a clear relationship exists between First Nations and the Crown, is a fundamental concept of the International Declaration on the Rights of Indigenous Peoples, to which Canada is a signatory.

1.1.1 Explain what measures were taken by BC Hydro to achieve and document FPIC of WMFN to the DCAT Project.

RESPONSE:

BC Hydro believes it is important to first place in proper context the International Declaration on the Rights of Indigenous Peoples in Canadian law and the reference to free, prior and informed consent contained within it.

Canada takes the position that the International Declaration is aspirational as opposed to a statement of international law. Canada supported adoption of the Declaration only after it had made that position unequivocally clear.

In its Statement of Support,[1] Canada stated its position on the International Declaration on the Rights of Indigenous Peoples as follows:

> **The Declaration is an aspirational document which speaks to the individual and collective rights of Indigenous peoples, taking into account their specific cultural, social and economic circumstances.**
>
> **Although the Declaration is a non-legally binding document that does not reflect customary international law nor change Canadian laws, our endorsement gives us the opportunity to reiterate our commitment to continue working in partnership with Aboriginal peoples in creating a better Canada. …**

[1] http://www.ainc-inac.gc.ca/ap/ia/dcl/stmt-eng.asp

> **In 2007, at the time of the vote during the United Nations General Assembly, and since, Canada placed on record its concerns with various provisions of the Declaration, including provisions dealing with lands, territories and resources; free, prior and informed consent when used as a veto…. These concerns are well known and remain. However, we have since listened to Aboriginal leaders who have urged Canada to endorse the Declaration and we have also learned from the experience of other countries. We are now confident that Canada can interpret the principles expressed in the Declaration in a manner that is consistent with our Constitution and legal framework.**

BC Hydro is guided by and has complied with the Constitution and legal framework of Canada, including the decisions of the Supreme Court of Canada regarding consultation with Aboriginal peoples, generally, and with respect to the DCAT Project.

The Text of the International Declaration on the Rights of Indigenous Peoples

The International Declaration on the Rights of Indigenous Peoples[2] makes reference to "free, prior and informed consent" in the following articles:

> **Article 10**
>
> **Indigenous peoples shall not be forcibly removed from their lands or territories. No relocation shall take place without the free, prior and informed consent of the indigenous peoples concerned and after agreement on just and fair compensation and, where possible, with the option of return.**
>
> **Article 11**
>
> **2. States shall provide redress through effective mechanisms, which may include restitution, developed in conjunction with indigenous peoples, with respect to their cultural, intellectual, religious and spiritual property taken without their free, prior and informed consent or in violation of their laws, traditions and customs.**
>
> **Article 19**
>
> **States shall consult and cooperate in good faith with the indigenous peoples concerned through their own representative institutions in order to obtain their free, prior and informed consent before adopting and implementing legislative or administrative measures that may affect them.**

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[2] **Full text available at: http://www.un.org/esa/socdev/unpfii/en/drip.html.**

Article 28

1. **Indigenous peoples have the right to redress, by means that can include restitution or, when this is not possible, just, fair and equitable compensation, for the lands, territories and resources which they have traditionally owned or otherwise occupied or used, and which have been confiscated, taken, occupied, used or damaged without their free, prior and informed consent.**

Article 29

2. **States shall take effective measures to ensure that no storage or disposal of hazardous materials shall take place in the lands or territories of indigenous peoples without their free, prior and informed consent.**

Article 32

1. **Indigenous peoples have the right to determine and develop priorities and strategies for the development or use of their lands or territories and other resources.**

2. **States shall consult and cooperate in good faith with the indigenous peoples concerned through their own representative institutions in order to obtain their free and informed consent prior to the approval of any project affecting their lands or territories and other resources, particularly in connection with the development, utilization or exploitation of mineral, water or other resources.**

BC Hydro does not believe that, on their face, five of these six articles—10 (forcible removal), 11(2) (restitution of seized property), 19 (legislative measures), 28 (confiscation of territories), and 29 (storage of hazardous waste)—have any application in the context of the present application for a CPCN for the DCAT Project. The remaining discussion will focus on Article 32.

BC Hydro does not believe Article 32 is engaged based on the circumstances in this case BC Hydro does not believe that the proposed Project impedes the ability of any First Nation to develop priorities and strategies for the development or use of their lands or territories and other resources. Nor does BC Hydro believe that the Project will require it to develop, utilize or exploit any mineral, water or other resources over which any First Nation makes a claim. The effects, if any, on WMFN of the Project would be on the rights conferred upon it by Treaty, not on any lands or territories held by it.

1.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 6, First Nations Consultation and Public Engagement
Free, Prior, and Informed Consent
NOTE: The WMFN suggests this IR is in addition to the BCUC IR #15.1.

No discussion is provided in the developer's Application documents (B-1, especially but not limited to, in Chapter 6) on the issue of free, prior and informed consent. Documentation of free, prior and informed consent (FPIC) of indigenous peoples to development on indigenous lands, and particularly Treaty lands where a clear relationship exists between First Nations and the Crown, is a fundamental concept of the International Declaration on the Rights of Indigenous Peoples, to which Canada is a signatory.

1.1.2 If any measures were taken, how were WMFN and other indigenous groups involved in evaluating the success of BC Hydro in meeting FPIC objectives?

RESPONSE:

As set out in the response to WMFN IR 1.1.1, BC Hydro does not believe FPIC is implicated in this case. However, WMFN and other indigenous groups may be involved in evaluating the success of BC Hydro's consultation efforts by (i) providing direct feedback to BC Hydro and/or (ii) providing their views to the BCUC or other decision-makers as appropriate.

1.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 6, First Nations Consultation and Public Engagement
Free, Prior, and Informed Consent
NOTE: The WMFN suggests this IR is in addition to the BCUC IR #15.1.

No discussion is provided in the developer's Application documents (B-1, especially but not limited to, in Chapter 6) on the issue of free, prior and informed consent. Documentation of free, prior and informed consent (FPIC) of indigenous peoples to development on indigenous lands, and particularly Treaty lands where a clear relationship exists between First Nations and the Crown, is a fundamental concept of the International Declaration on the Rights of Indigenous Peoples, to which Canada is a signatory.

1.1.3 Has BC Hydro received a statement of FPIC in relation to the DCAT project from any potentially affected Aboriginal group?

RESPONSE:

To date, BC Hydro has not received any statements from WMFN or from any other potentially affected Aboriginal group taking a definitive position regarding the DCAT Project.

1.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 6, First Nations Consultation and Public Engagement
Free, Prior, and Informed Consent
NOTE: The WMFN suggests this IR is in addition to the BCUC IR #15.1.

No discussion is provided in the developer's Application documents (B-1, especially but not limited to, in Chapter 6) on the issue of free, prior and informed consent. Documentation of free, prior and informed consent (FPIC) of indigenous peoples to development on indigenous lands, and particularly Treaty lands where a clear relationship exists between First Nations and the Crown, is a fundamental concept of the International Declaration on the Rights of Indigenous Peoples, to which Canada is a signatory.

1.1.4 If FPIC has not been adequately achieved and documented, how has BC Hydro accounted for the increased risk created by the absence of FPIC specific to the Project?

RESPONSE:

As set out in the response to WMFN IR 1.1.1, BC Hydro does not believe FPIC is implicated in this case.

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

"First Nations have been consulted with respect to the Project as detailed in section 6.1 of this application. As with general public engagement, no significant issues were raised with respect to the Alternatives."

1.2.1 Please identify if, how, and in what amount did BC Hydro provided funding to WMFN in order to support due consideration of DCAT alternatives and design by WMFN, to consider the potential of various alternatives to impact the rights, interests and uses of WMFN, and to provide feedback designed to inform BC Hydro decisions regarding alternatives.

RESPONSE:

This information response is being filed in confidence in accordance with section 42 of the B.C. *Administrative Tribunals Act* and the Confidential Filing Practice Directive.

This response filed confidentially relates to First Nation funding or agreement details. The release of such information may generally prejudice negotiations with First Nations.

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

"First Nations have been consulted with respect to the Project as detailed in section 6.1 of this application. As with general public engagement, no significant issues were raised with respect to the Alternatives."

1.2.2 Please advise how the developer came to a conclusion that it had chosen the appropriate routing alternatives, and that the project is unlikely to cause significant adverse impacts on any VEC or VSC, in the absence of traditional land use (TLU) and traditional knowledge (TK) from WMFN, a primary land user and Treaty and Aboriginal rights holder in the area.

RESPONSE:

The referenced quotation is from Exhibit B-1, Chapter 3, which addresses Project Alternatives, as opposed to route options, which are addressed in Chapter 4. The second sentence of the referenced quotation is incomplete. The entire sentence states:

> **"As with general public engagement, no significant issues were raised with respect to the Alternatives, however the need for fewer structures and decommissioning of portion of the existing 138 kV line under Alternative 1 were generally viewed favourably."**

To be consistent with the reference provided, the following response relates to Project Alternatives.

BC Hydro selected Alternative 1 as the preferred alternative on the basis of information available to it. The input received from First Nations, including WMFN, regarding the alternatives under consideration was that the alternative with fewer structures and the decommissioning of a portion of the existing 138 kV line was preferable. BC Hydro took this input into consideration in its evaluation of the alternatives and the selection of Alternative 1. Apart from this input, no other issues were raised by First Nations regarding the respective merits of the alternatives under consideration.

The conclusion with respect to the potential adverse impact of the Project on VECs and VSCs is found at Exhibit B-1, page 5-2, and relates to route options, not Project alternatives. For ease of reference, the conclusion is quoted below:

"The Project has the potential to adversely affect the environment, especially during construction. However, the EOA concludes that following the implementation of appropriate mitigations: 1) the Project will have a low or negligible effect on almost all the Valued Ecosystem Components (VECs) and the Valued Social Components (VSCs); and 2) there is no measurable difference among the options under consideration for almost all VECs and VSCs (Table 5-1). The only exception is that for vegetation, the residual effect on the alteration of ecosystems was considered moderate for Options C1, C3, W1, and W2."

Based on the EOA, AMEC has recommended a number of measures to avoid, reduce, mitigate or compensate for the potential adverse environmental effects of the Project. The mitigation measures and residual effects rating for all disciplines are outlined in Table 5-1 by the VECs or VSCs for the Project.

Please refer to the response to WMFN IR 1.8.1 for an explanation of how AMEC was able to reach this conclusion in the absence of TLU and TK information from WMFN.

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

"First Nations have been consulted with respect to the Project as detailed in section 6.1 of this application. As with general public engagement, no significant issues were raised with respect to the Alternatives."

1.2.3 Please indicate what methods, thresholds or measures BC Hydro used to determine what issues raised by First Nations with respect to the Alternatives were of significance and what issues were not.

RESPONSE:

The only issue communicated by First Nations to BC Hydro that was significant to the evaluation of the alternatives was the difference between the number of structures and decommissioning of the line, which BC Hydro took into account in its selection of the preferred alternative. Please refer to the response to WMFN IR 1.2.2.

As such, BC Hydro did not conduct an evaluation of issues raised by First Nations, and no methods, thresholds or measures to make such an evaluation were used.

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

"First Nations have been consulted with respect to the Project as detailed in section 6.1 of this application. As with general public engagement, no significant issues were raised with respect to the Alternatives."

1.2.4 Please identify whether input from WMFN was sought in determining criteria, thresholds of acceptable change, or other metrics used to assess "significance" of issues and potential project outcomes.

RESPONSE:

Please refer to the response to WMFN IR 1.2.3.

2.0 Reference: First Nations Consultation
Exhibit B-1, Chapter 3, Section 3.3.5.3, p. 13
First Nations Input in the Evaluation of Alternatives
NOTE: This is a related extension of BCUC IR #1.1

Exhibit B-1, Chapter 4, Section 4.3.2.1 – p. 11

"A number of sub-options have been identified to route away from homes, where possible, and to minimize potential conflicts with pipeline infrastructure. BC Hydro will continue to evaluate these sub-options in the detailed design to confirm the specific routing in those areas."

1.2.5 Should the project be permitted and proceed, please identify how future WMFN input in micro-route changes will be incorporated into final project routing plans, and when.

RESPONSE:

BC Hydro has advised WMFN that it remains open to meaningful consultation. BC Hydro will consider any information it receives through consultation and will assess whether any micro-route changes or other accommodation would be appropriate.

Please also refer to the response to BCUC IR 1.13.4.1.

3.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 3, Section 3.3, pp. 7 and 8
Criteria Used to Assess Alternative Line Routes and Infrastructure Locations

"In addition to financial considerations, BC Hydro also considered externalities such as reliability outcomes of the proposed alternatives, environmental, First Nation and social considerations in its planning level decision-making process in identifying a preferred alternative."

1.3.1 Please clarify what "First Nation…considerations" were used in planning level decision-making processes in identifying preferred alternatives.

RESPONSE:

Please refer to the responses to WMFN IRs 1.2.2, 1.2.3 and 1.4.1.

3.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 3, Section 3.3, pp. 7 and 8
Criteria Used to Assess Alternative Line Routes and Infrastructure Locations

"In addition to financial considerations, BC Hydro also considered externalities such as reliability outcomes of the proposed alternatives, environmental, First Nation and social considerations in its planning level decision-making process in identifying a preferred alternative."

1.3.2 Please indicate if and how Aboriginal and Treaty rights "considerations" specific to WMFN were included in the criteria used to assess the alternative line routes and other project component alternatives.

RESPONSE:

The referenced quotation is found in Exhibit B-1, Chapter 3, Project Alternatives. Route options are discussed in Chapter 4, Project Description. Please refer to the responses to WMFN IRs 1.2.2, 1.2.3 and 1.4.1 for a discussion of First Nations considerations with respect to Project Alternatives. Please refer to the response to WMFN IR 1.3.3 for a discussion of the route option assessment and selection process.

BC Hydro sent WMFN maps with the route options and requested WMFN feedback on the route options a number of times between November 2010 and March 2011, as detailed below. To date, WMFN has not provided BC Hydro with any information specific to the route options and WMFN Aboriginal and treaty rights for BC Hydro to consider.

- **On November 12, 2010, BC Hydro e-mailed the WMFN Land Use Manager and attached the revised overview map and three detailed segment maps (West, Central and East).**

- **On January 7, 2011, BC Hydro e-mailed the WMFN Lands Use Manager attaching the West Segment map, East Segment map, and Central Segment maps. BC Hydro suggested January 17 or 18, 2011 as potential dates to discuss feedback regarding the route options in the attached maps. Please refer to Exhibit B-1, Appendix G, page 64.**

- **On January 18, 2010, BC Hydro e-mailed WMFN attaching segment maps showing the route options and proposed reference route. BC Hydro further advised that a binder with Project information had been sent to WMFN**

BC Hydro requested WMFN's availability to meet in February. Please refer to Exhibit B-1, Appendix G, page 78.

- **On January 18, 2011, BC Hydro sent a binder to WMFN enclosing information regarding the Project. The binder included the correspondence to that date, including an update letter and the segment maps showing the route options and proposed reference route. Please refer to Exhibit B-1, Appendix G, pages 92 to 93.**

- **On January 21, 2011, BC Hydro e-mailed the WMFN Lands Use Manager and attached a preliminary map showing the land ownership along the proposed route options. The proposed reference route (options E1, C1 and W1) traveled mainly through private property with small sections through Crown lands. Please refer to Exhibit B-1, Appendix G, pages 103 to 104.**

- **On January 26, 2011, as requested by WMFN, BC Hydro sent a follow-up email requesting to schedule a meeting on February 8, 2011 to review the maps showing the route options, and any additional information regarding the Project.**

- **On February 8, 2011, BC Hydro met with the WMFN Land Use Manager and provided a status update on the Project, including the route options under review.**

- **On February 22, 2011, BC Hydro e-mailed the WMFN Land Use Manager and attached meeting notes from February 8, 2011 for review. BC Hydro also e-mailed the WMFN Land Use Manager and attached a link to the Dawson Creek to Chetwynd Area Project website**

- **On March 10, 2011, BC Hydro sent a letter to WMFN's Chief and enclosed the draft Environmental Overview Assessment (EOA) report, which included the route options, and a First Nation Comment Form. BC Hydro requested comments from WMFN within 30 days. At the time the Application was filed on July 7, 2011, BC Hydro had received no response from WMFN.**

Please refer to the responses to BCUC IRs 1.9.2, 1.13.4 and 1.13.4.1.

3.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 3, Section 3.3, pp. 7 and 8
Criteria Used to Assess Alternative Line Routes and Infrastructure Locations

"In addition to financial considerations, BC Hydro also considered externalities such as reliability outcomes of the proposed alternatives, environmental, First Nation and social considerations in its planning level decision-making process in identifying a preferred alternative."

1.3.3 Please identify any weighting used for different criteria in assessment of project and routing/siting alternatives, how this weighting was determined, and whether any WMFN representatives were involved in either the determination of appropriate criteria or determination of appropriate criteria weighting.

RESPONSE:

The referenced quotation is found in Exhibit B-1, Chapter 3, Project Alternatives. Route options are discussed in Chapter 4, Project Description. Please refer to the responses WMFN IRs 1.2.2, 1.2.3 and 1.4.1 for a discussion of the First Nations considerations with respect to Project Alternatives. Please refer to Exhibit B-1, Chapter 4, pages 4-7 to 4-14 for a discussion of the assessment and selection of route options (as opposed to Project Alternatives).

The evaluation criteria applied to the route options were not given weightings. Rather, a comparative analysis was undertaken whereby if a criterion was the same or similar for the route options being evaluated, then that criterion was not a deciding factor in the selection of the route option. However, if a criterion was different for the options being evaluated, then that difference was taken into consideration in the evaluation of those options. Thus, if two options were the same length, then length was not a contributing factor. However, if two options had different clearing amounts, then that difference was considered in the selection of the preferred route. WMFN representatives were not involved in the determination of appropriate criteria.

In comparing the route options for the Project, BC Hydro considered the First Nations input it had received through the consultation process indicating a preference for minimizing the use of Crown lands and minimizing environmental impacts, which favoured route options that would follow existing transmission lines where possible, thereby reducing right of way width and clearing requirements and making use of existing access. Please refer to Exhibit B-1, Chapter 6, pages 6-11 and 6-17.

To illustrate, in comparing the route options for the Central Segment, the need for a new corridor and associated access roads through relatively undisturbed, forested Crown lands, and the associated higher potential impact on wildlife and riparian habitat were deciding factors in the rejection of Option C3. Please refer to Exhibit B-1, Chapter 4, page 4-11.

3.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1, Chapter 3, Section 3.3, pp. 7 and 8
Criteria Used to Assess Alternative Line Routes and Infrastructure Locations

"In addition to financial considerations, BC Hydro also considered externalities such as reliability outcomes of the proposed alternatives, environmental, First Nation and social considerations in its planning level decision-making process in identifying a preferred alternative."

1.3.4 Please provide a table listing all instances where input from WMFN representatives has led to project routing alterations, or any other project planning changes for the proposed DCAT project, including the source(s) of the information that led to the project alteration.

RESPONSE:

BC Hydro has not received any input from WMFN representatives regarding the route options or other aspects of the Project that have led to alterations to the Project.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

"In addition to the technical evaluation of alternatives, a number of other considerations may impact selection of a preferred alternative for the Project. These considerations may include environmental review, First Nation consultation and public input. Specifically with respect to this project, as Alternative 1 and 2 generally require substantially similar land use in the same areas such considerations did not materially impact choice of a preferred alternative. "

1.4.1 Please identify how it was determined that WMFN land use for practicing Treaty and Aboriginal rights in the areas covered by Alternatives 1 and 2 were "substantially similar", including what traditional or current land use studies or other sources were used to make this determination.

RESPONSE:

The referenced quotation is a statement regarding the land use by Alternatives 1 and 2. Please refer to Exhibit B-1, Figures 3-1 and 3-2, which illustrate that the land use by Alternatives 1 and 2 is substantially similar and in the same areas. The referenced quotation is not a statement about land use by First Nations, including WMFN.

Moreover, the referenced quotation states that because the land use by each of Alternatives 1 and 2 is substantially similar and in the same areas, this factor (i.e., the land use by the Alternatives 1 and 2) did not materially impact the choice of the preferred alternative.

The referenced quotation does not state that First Nations considerations should not materially impact the choice of the preferred alternative. Rather, it states that First Nations consultation was considered in the selection of the preferred alternative. Specifically, BC Hydro considered the input received through the consultation process from First Nations, including WMFN, that the alternative with fewer structures and the decommissioning of a portion of the existing 138 kV line was preferable. Please refer to the response to WMFN IR 1.2.2.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

"In addition to the technical evaluation of alternatives, a number of other considerations may impact selection of a preferred alternative for the Project. These considerations may include environmental review, First Nation consultation and public input. Specifically with respect to this project, as Alternative 1 and 2 generally require substantially similar land use in the same areas such considerations did not materially impact choice of a preferred alternative. "

1.4.2 If no WMFN traditional and current land use studies related to the proposed development have been incorporated into the project assessment, please indicate how BC Hydro was able to determine that "First Nation consultation… considerations" should not "materially impact" on alternatives assessments.

RESPONSE:

Please refer to response to WMFN IR 1.4.1.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

"In addition to the technical evaluation of alternatives, a number of other considerations may impact selection of a preferred alternative for the Project. These considerations may include environmental review, First Nation consultation and public input. Specifically with respect to this project, as Alternative 1 and 2 generally require substantially similar land use in the same areas such considerations did not materially impact choice of a preferred alternative. "

1.4.3 Will the WMFN be provided further opportunities to provide meaningful input into alternatives consideration, routing of the transmission line, siting of project components, and micro-routing decisions during detailed project planning? If so, please provide details on the methods BC Hydro will use to engage the WMFN in detailed project planning and siting determinations.

RESPONSE:

Please refer to the responses to BCUC IRs 1.9.1 and 1.13.4.1.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

Exhibit B-1, Chapter 4, Section 4.3.2.1, pp. 4-7, 4-8

"The route evaluation is based on a number of objectives, which include minimizing potential impacts to the environment, private landowners, First Nation interests, archaeological sites, project cost, reducing project construction and schedule risk, and maximizing maintainability. Criteria were developed against these objectives; they include construction cost, length of line and number of poles, constructability and access, potential impact on wildlife and riparian habitat, amount of private and Crown land, existing dwellings located near the line, First Nations consultation, and archaeological potential or location of known archaeological sites. The route options within each segment were evaluated against these criteria.

1.4.4 It is not clear what the "First Nations consultation" criteria referred to above is composed of. Please clarify.

RESPONSE:

Please refer to the response to WMFN IR 1.3.3.

4.0 Reference: Role of First Nations Consultation in Alternatives Assessment
Exhibit B-1, Chapter 3, Section 3.3.5 , p. 3-12
Other Considerations

Exhibit B-1, Chapter 4, Section 4.3.2.1, p. 4-9

"Option E1 was selected as the preferred route for the east segment of the transmission line. Option E1 has a lower impact on private property owners but a higher constructability risk as compared to Option E2 and Option E3. On balance these differences in the criteria used to compare the three options did not identify an option that was superior to the other two options and therefore Option E1 has been selected since it is the lowest cost."

1.4.5 The discussion noted above makes it appear that alternative routing alignments were determined on the basis of two criteria – impact on property owners and constructability risk. Please clarify whether and how "First Nations consultation" criteria was used in assessment of routing alternatives.

RESPONSE:

The route options were evaluated on a comparative basis using a number of considerations. If a consideration was the same or similar for each route option, then it no longer figured into the evaluation. For example, if all route options were the same length, then route length was not a determining factor in the evaluation and selection of the preferred route option.

In the case of the East Segment, all three route options were designed to parallel existing linear infrastructure (i.e., rail, road, transmission) in order to reduce habitat fragmentation. As such, this consideration, which is reflected in the First Nations input received through the consultation process (please refer to the response to WMFN IR 1.3.3), was considered in the process of evaluating the route options but was not a deciding factor in the selection of the preferred route option because it was similar for all three East Segment route options.

Option E3 was eliminated because it had a higher cost, higher potential impacts on private property owners, and higher constructability risk and maintenance issues as a result of the necessity for compact pole design. Please refer to Exhibit B-1, Chapter 4, page 4-9, lines 1 to 9.

The remaining route Options E1 and E2 were similar. Option E2 had a higher potential impact on private landowners, slightly higher cost, and slightly lower potential impact on riparian habitat than Option E1. However, the impact on the riparian area could be mitigated by constructing in winter, and therefore Option E1 was selected as the preferred route in the East Segment.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.1 Please clarify if and how WMFN members were involved in the collection of TLU and TK information that was integrated into the developer's Application and supporting documents.

RESPONSE:

This information response is being filed in confidence in accordance with section 42 of the B.C. *Administrative Tribunals Act* and the Confidential Filing Practice Directive.

This response filed confidentially relates to First Nation funding or agreement details. The release of such information may generally prejudice negotiations with First Nations.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.2 Please identify how much funding was provided to the WMFN to support documentation of baseline cultural and environmental information, and associated assessment in a manner that contributes to the assessment.

RESPONSE:

Please refer to the response to WMFN IR 1.2.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.3 Please identify whether BC Hydro is of the view that the funding it has provided has been adequate and provided within a reasonable timeline to support WMFN involvement, including but not limited to:

1.5.3.1 Determination of relevant, culturally appropriate Valued Ecosystem Components (VECs) and Valued Social Components (VSCs).

RESPONSE:

Please refer to the response to WMFN IR 1.2.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.3 Please identify whether BC Hydro is of the view that the funding it has provided has been adequate and provided within a reasonable timeline to support WMFN involvement, including but not limited to:

1.5.3.2 Collection of relevant cultural and environmental baseline data, for VECs/VSCs.

RESPONSE:

Please refer to the response to WMFN IR 1.2.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.3 Please identify whether BC Hydro is of the view that the funding it has provided has been adequate and provided within a reasonable timeline to support WMFN involvement, including but not limited to:

1.5.3.3 The assessment of Alternatives.

RESPONSE:

Please refer to the response to WMFN IR 1.2.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.3 Please identify whether BC Hydro is of the view that the funding it has provided has been adequate and provided within a reasonable timeline to support WMFN involvement, including but not limited to:

1.5.3.4 Significance estimations and input regarding determination of appropriate mitigation.

RESPONSE:

Please refer to the response to WMFN IR 1.2.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.4 Please identify what actual concrete information the developer and its consultants collected on the value of areas proximate to the proposed development for TLU and historical values associated with the areas by WMFN members?

RESPONSE:

Please refer to the responses to BCUC IR 1.9.2 and WMFN IR 1.9.1.

5.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 6, Section 6.1.6.1
Adequacy of WMFN Opportunities for Input in Preliminary Project Evaluation
NOTE: Linked to BCUC IR#13

1.5.5 Please clarify any remaining hurdles to incorporation of appropriate WMFN TLU/TK into the currently planned BCUC regulatory timelines, how the developer plans to overcome them, and what effect on the reliability of impact predictions the lack of this information would have on the process.

RESPONSE:

BC Hydro is not aware of any existing hurdles based on the available information provided to date by WMFN.

If WMFN provides the information requested by letter from BC Hydro to WMFN dated September 8, 2011, then BC Hydro will consider: how to incorporate that information into the planned BCUC regulatory timelines; whether any hurdles arise and if any, how to overcome those hurdles; and any effects the information may have on the assessment of potential adverse impacts of the Project on the exercise of treaty rights.

The September 8, 2011 letter is provided in Confidential Attachment 1 to the response to BCUC IR 1.9.1.

6.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 2, Section 2.3
Consistency of Load Forecast with Treaty and Aboriginal Rights

The need for the DCAT project is based on a load forecast that anticipates rapid industrial growth of the Montney shale gas fields.

1.6.1 How has BC Hydro confirmed that the level and pace of growth anticipated for the Montney shale gas fields is consistent with the current and future practice of WMFN rights associated with Treaty No. 8 and with S. 35 of the *Constitution Act, 1982*?

RESPONSE:

BC Hydro has not determined that the level and pace of growth anticipated for the Montney shale gas fields is consistent with the current and future practice of WMFN rights under Treaty No. 8 and pursuant to section 35 of the *Constitution Act, 1982.* The construction of the proposed transmission line will not be a determining factor in connection with other development of Montney shale gas.

As noted in Exhibit B-1, page 2-9, lines 5 to 22, and page 2-15, lines 2 to 4, the development of shale gas fields can occur without the use of electricity supplied from the BC Hydro grid. Notwithstanding the benefits of using electricity for compression, BC Hydro understands that decision to proceed with development of the Montney shale gas fields does not depend on the building of the DCAT Project and the use of electricity for compression. Accordingly, BC Hydro is of the view that the scope of consultation on the DCAT Project should be limited to the impacts of the DCAT Project only.

As discussed in Exhibit B-1, pages 2-18 and 2-19, BC Hydro recognizes the uncertainty around the use of electricity for compression. To mitigate this risk, BC Hydro will seek security arrangements with the five customers with interconnection requests.

6.0 Reference: First Nations Consultation and Accommodation
Exhibit B-1; Chapter 2, Section 2.3
Consistency of Load Forecast with Treaty and Aboriginal Rights

The need for the DCAT project is based on a load forecast that anticipates rapid industrial growth of the Montney shale gas fields.

1.6.2 If BC Hydro has not confirmed this, how has BC Hydro accounted for associated risks?

RESPONSE:

Please refer to the response to WMFN IR 1.6.1.

7.0 Reference: First Nation Consultation Summary
Exhibit B-1; Chapter 6, Section 6.1.6.1, p.17
Adequacy and accuracy of BC Hydro's description of consultation with the WMFN to date
NOTE: Related to and building on BCUC IR #9

"West Moberly First Nation asked questions related to BC Hydro's plans for river crossings and for utilizing the existing ROW, and identified concerns related to potential impacts to wildlife (fragmentation, wildlife corridors, and a wetland area used by moose). BC Hydro responded that route investigations were beginning, with a view to running parallel to existing transmission lines where possible, that an environmental overview assessment would be undertaken, and that BC Hydro was looking into removing some of the existing transmission lines after the new ones were in service. West Moberly First Nation indicated that they would also want to review the environmental overview assessment results."

A preliminary review of BC Hydro's "summary of consultation to date" raises troubling inconsistencies between the perspectives of the relationship as described by BC Hydro versus that of WMFN. The consultation record provided by BC Hydro does not accurately and completely reflect the issues that have been raised to this point, and in addition it downplays the lack of meaningful and timely funding and support from BC Hydro for required involvement of WMFN in cultural and environmental studies, including impact assessments requested by WMFN.

1.7.1 Please provide a revised and updated "summary of consultation", providing further details on the content of all correspondence, communications and meetings between representatives of WMFN and the developer and its representatives in relation to this file, from inception to present.

RESPONSE:

BC Hydro summarized the consultation with WMFN as fully and fairly as it could in section 6.1 of Exhibit B-1.

The summary of consultation in the Application was up to May 2011. For a complete summary of communications with WMFN to date, please refer to the confidential response to WMFN IR 1.5.1, which describes as accurately as BC Hydro can, the record of consultation with WMFN.

A Consultation Log is attached as Confidential Attachment 1 to this response.

This information is being filed in confidence in accordance with section 42 of the B.C. *Administrative Tribunals Act* and the Confidential Filing Practice Directive.

This confidential information relates to First Nation funding or agreement details. The release of such information may generally prejudice negotiations with First Nations.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

7.0 Reference: First Nation Consultation Summary
Exhibit B-1; Chapter 6, Section 6.1.6.1, p.17
Adequacy and accuracy of BC Hydro's description of consultation with the WMFN to date
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A preliminary review of BC Hydro's "summary of consultation to date" raises troubling inconsistencies between the perspectives of the relationship as described by BC Hydro versus that of WMFN. The consultation record provided by BC Hydro does not accurately and completely reflect the issues that have been raised to this point, and in addition it downplays the lack of meaningful and timely funding and support from BC Hydro for required involvement of WMFN in cultural and environmental studies, including impact assessments requested by WMFN.

1.7.2 There doesn't appear to be any plain language summary of the application, making it difficult for WMFN representatives to review the documentation and seek feedback from WMFN members on this application. Please provide a plain language summary of the Application materials for review by WMFN with its membership.

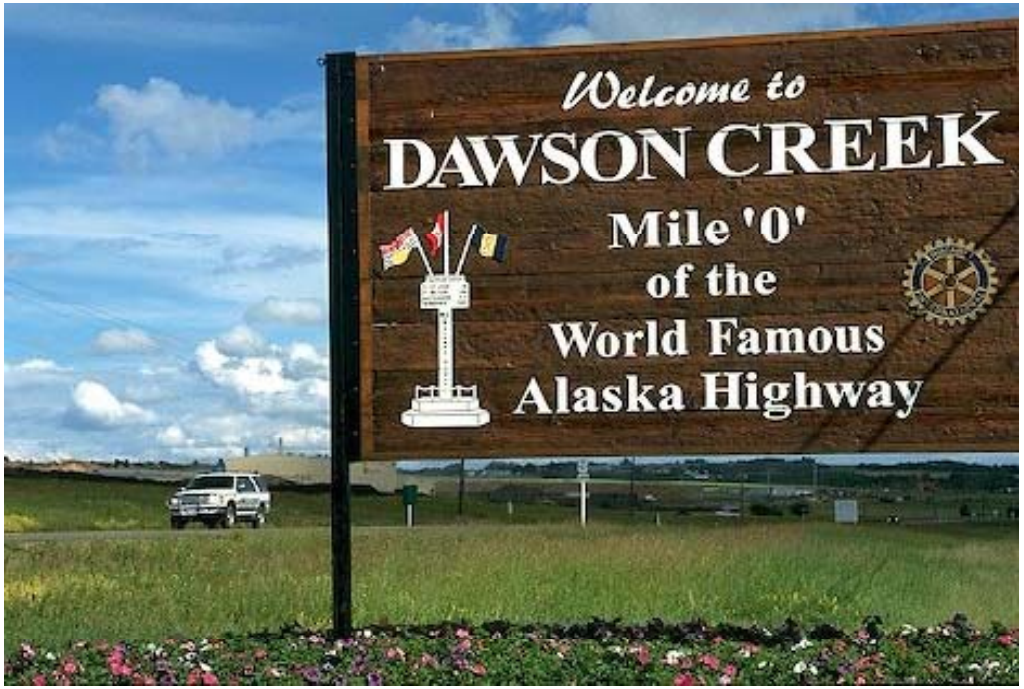
RESPONSE:

Please refer to the attached copy of the Dawson Creek / Chetwynd Area Transmission Project CPCN Application Information Session Workshop presentation dated July 20, 2011, that BC Hydro sent to West Moberly First Nations Chief and Council and emailed to the West Moberly First Nations Land Use Manager on July 27, 2011.

Dawson Creek/Chetwynd Area Transmission Project

CPCN Application Information Session

July 20, 2011



BC hydro

FOR GENERATIONS

WMFN IR 1.7.2 Attachment 1

INTRODUCTION

BC hydro
FOR GENERATIONS

WORKSHOP AGENDA

- Introduction and Application Overview (Geoff Higgins);
- BC Hydro's Load Forecast (David Ince);
- Existing Regional Transmission System Overview (Eric Desjardins);
- Alternatives Analysis (Eric Desjardins);
- Project Description (Brooke Dutka)
- First Nations Consultation and Public Engagement (Brooke Dutka);
- Project Risk and Risk Mitigation (Brooke Dutka/Chris Heminsley);
- Rate Impact and BCUC Regulatory Timetable (Geoff Higgins)

CPCN Application Overview

BC hydro
FOR GENERATIONS

APPLICATION STRUCTURE

- Chapter 1 – Introduction
- Chapter 2 – Project Justification
- Chapter 3 – Project Alternatives
- Chapter 4 – Project Description
- Chapter 5 – Environmental and EMF
- Chapter 6 - First Nations Consultation and Public Engagement
- Chapter 7 – Project Risks and Risk Management

CPCN Application Overview

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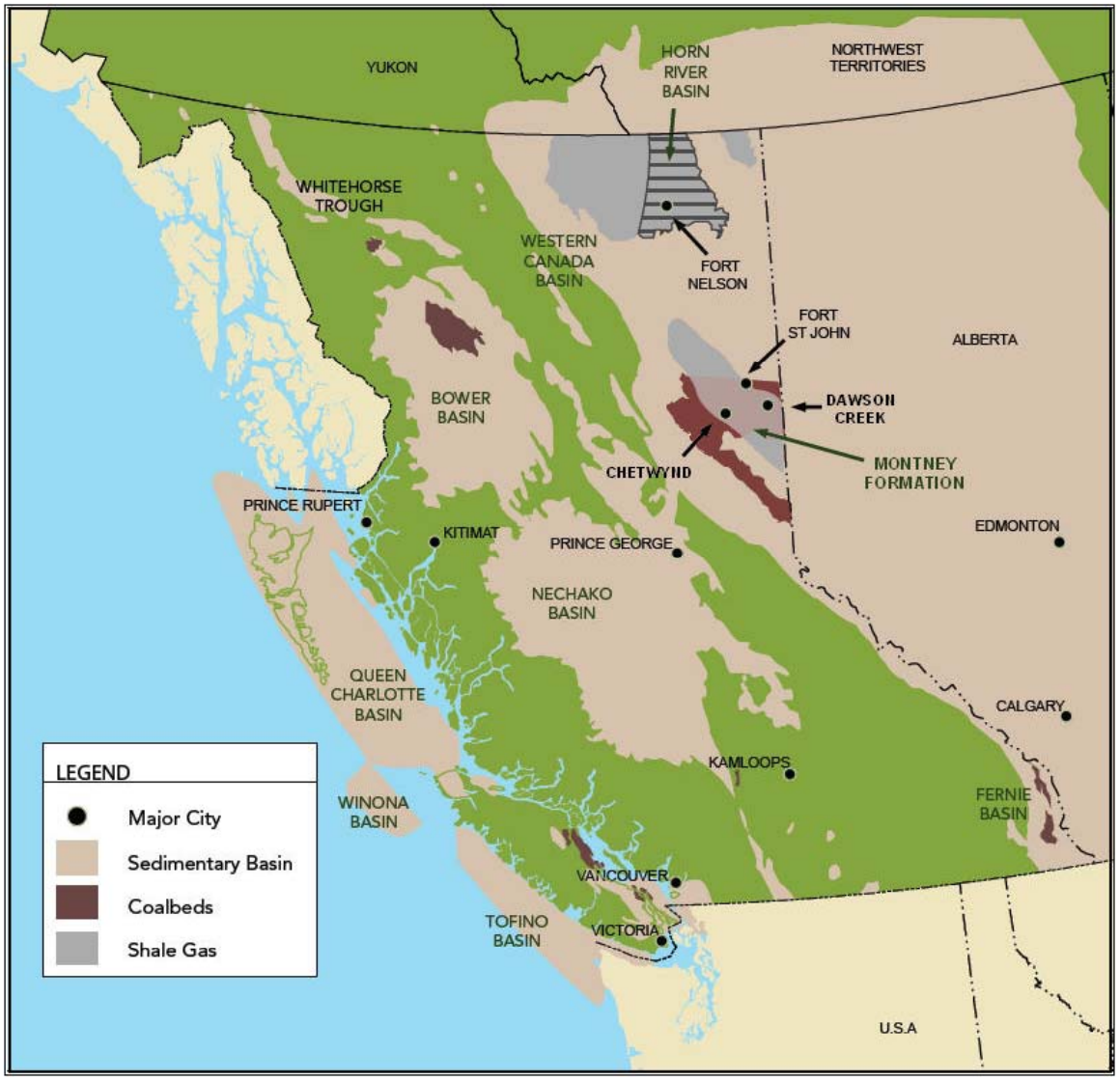
ORDER SOUGHT

- Pursuant to subsection 46(1) of the *Utilities Commission Act (UCA)*, BC Hydro filed its application for the BCUC to grant a CPCN to construct and operate the Dawson Creek/Chetwynd Area Transmission Project (Project);
- Pursuant to section 58 and 61 of the UCA, to have section 8.3 of the Electric Tariff Terms and Conditions revised to allow security for the cost of transmission reinforcements from appropriate distribution customers.
- Set out in Appendix A; reporting requirements similar to other projects;

Load Forecast

- 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 above its maximum firm rated capacity (N-1) and is forecasted to exceed its maximum non-firm rated capacity (N-0) in the winter of 2013/14.
- The DCAT load forecast is consistent with BC Hydro's annual 2010 Electric Forecast (available on BC Hydro's website or as Exhibit B-4 of the Ruskin Dam and Powerhouse Upgrade Project Application filed with the BCUC).
- The biggest component of load growth in the 2010 Load Forecast is for those new customers in the mining and the oil and gas sectors who are assumed to install new electrically-intensive equipment.
- In addition to the immediate needs of the Peace region, BC Hydro is anticipating some of the most dramatic, single industry load growth in a discrete area that it has experienced in recent history.

Unconventional Gas in BC



Adapted from: B.C. Ministry of Energy and Mines and the National Energy Board report: "Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin", April, 2011.

Montney Gas Production Forecast

BC hydro
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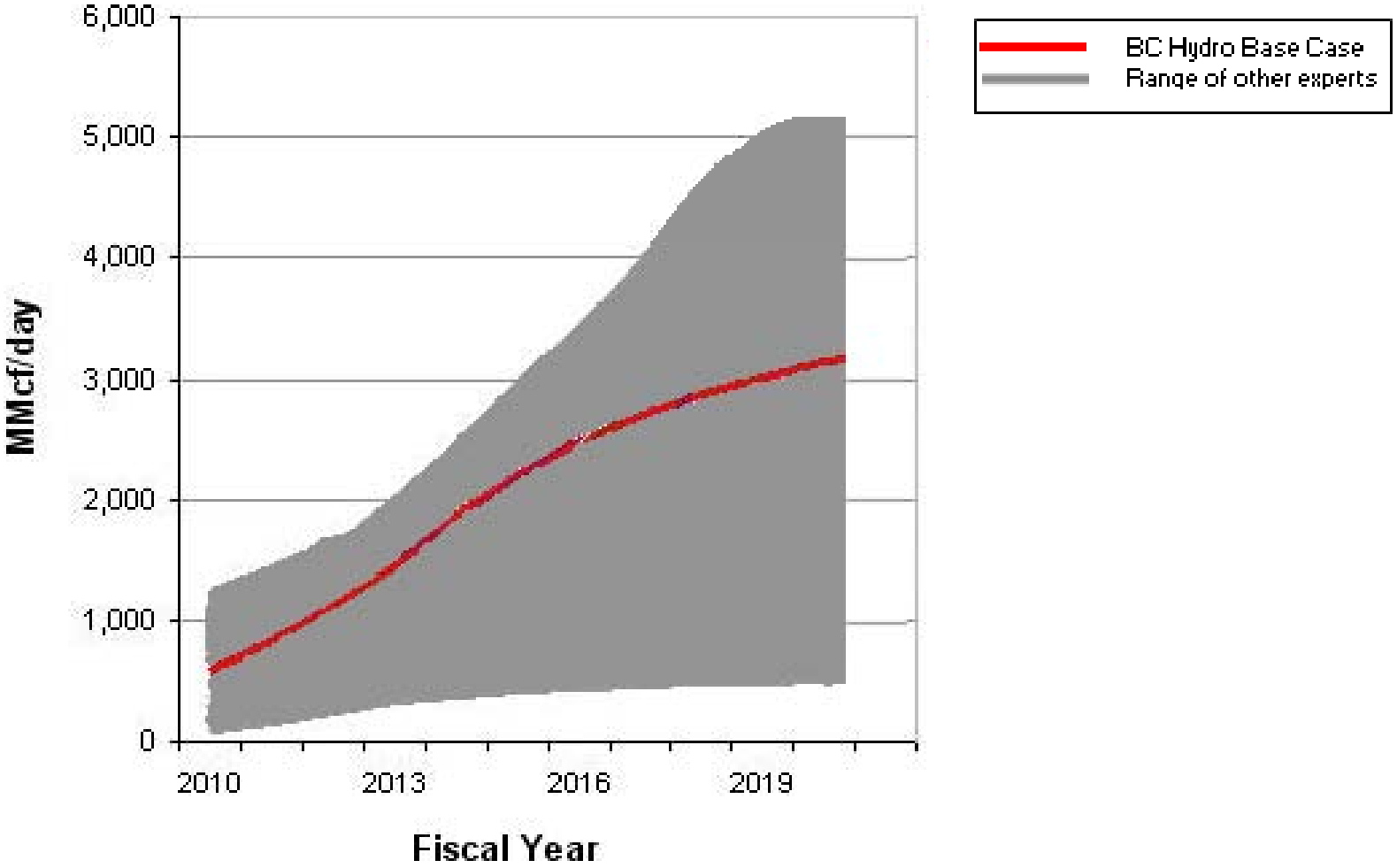

Dawson Creek Transmission System

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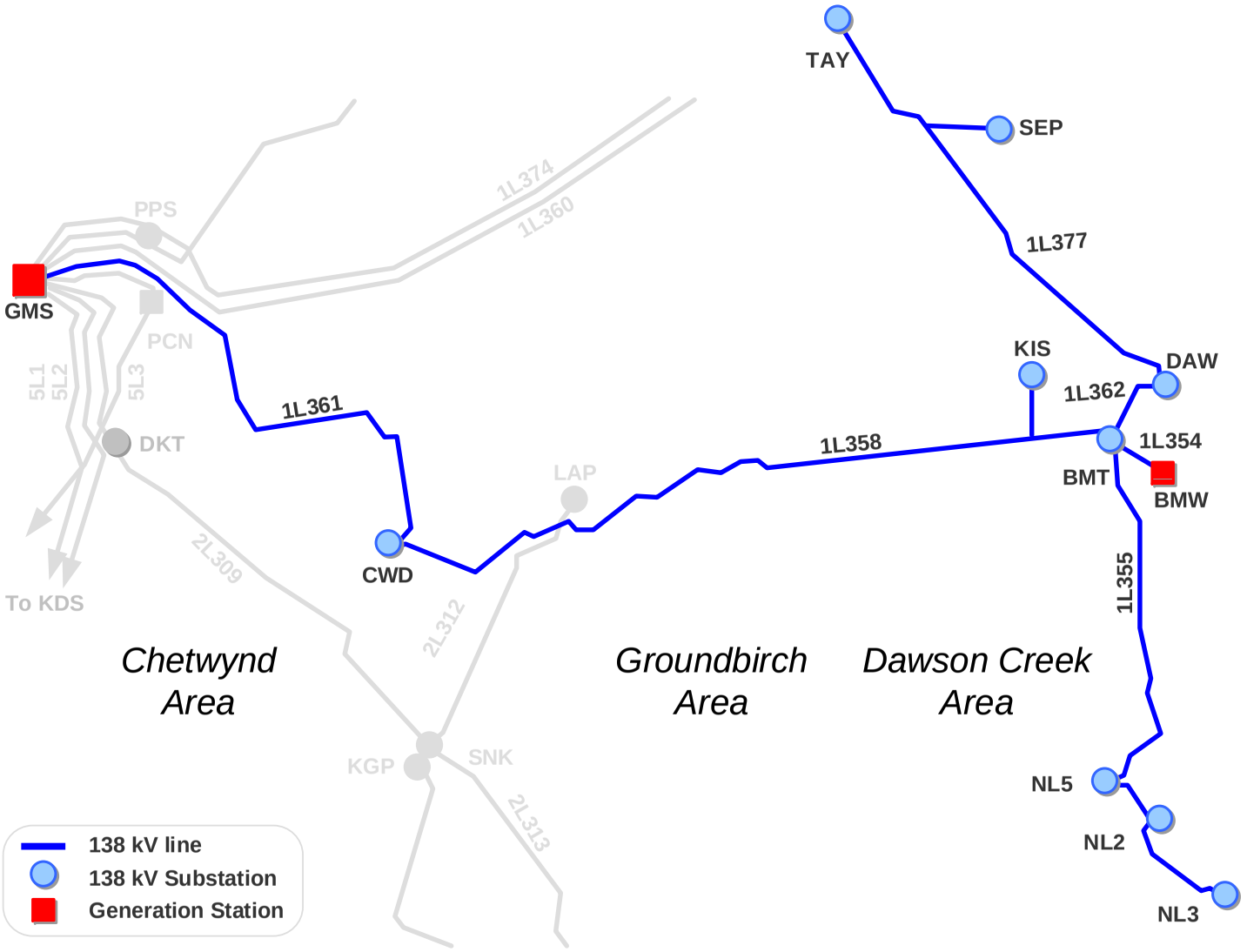
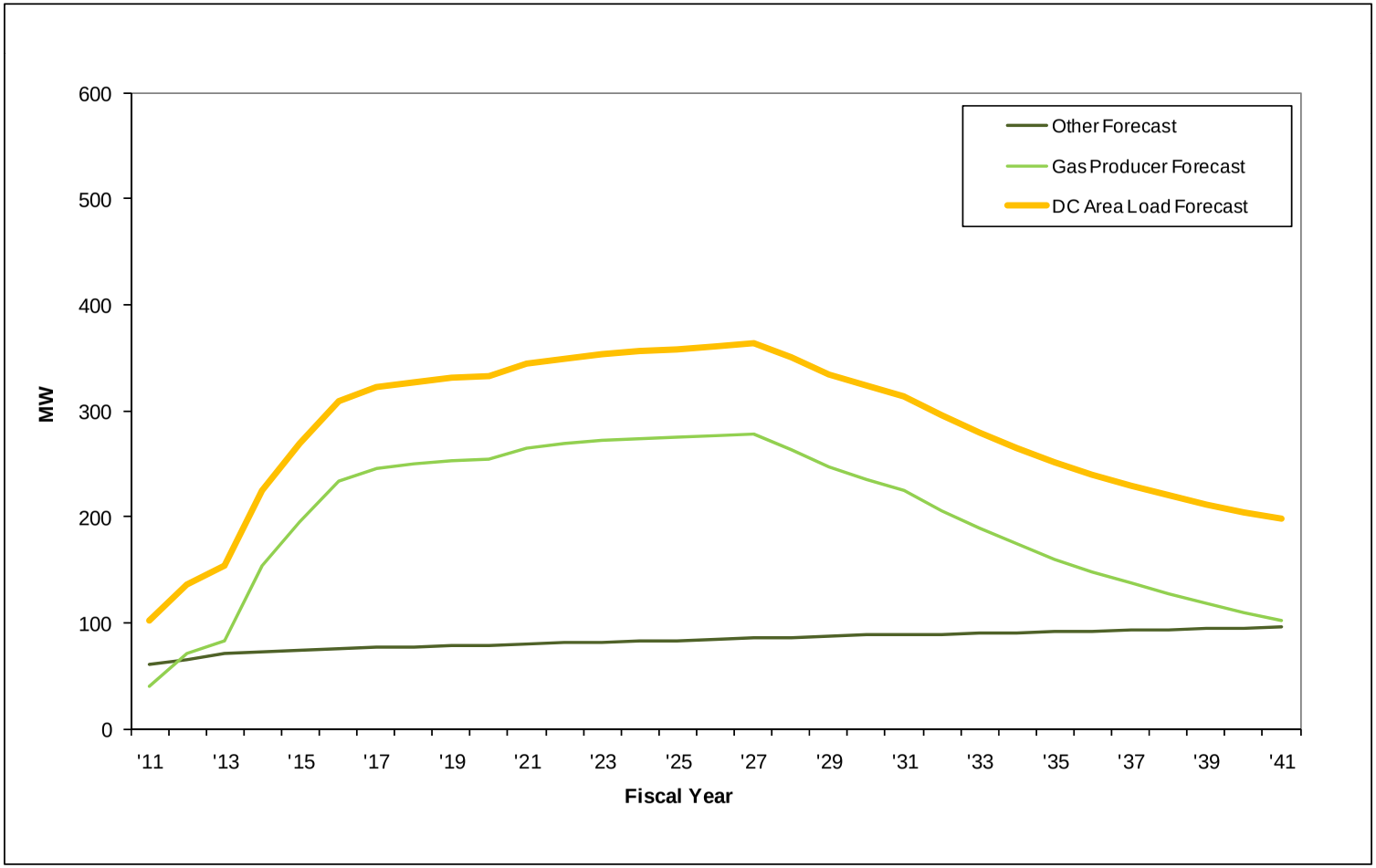


Load Forecasts

- Reference (P50) load forecast without Demand Side Management (DSM) for the Dawson Creek and Groundbirch areas for the period 2011 to 2041 (DC Area Load Forecast)
- P50 refers to the expectation that the Reference forecast is expected to be high (or low) relative to actual loads 50% of the time.
- The DSM savings associated with unconventional gas loads are expected to be in the area of 4-7 per cent, and for all other types of loads the DSM savings could reach 6-9 per cent.

Dawson Creek and Groundbirch areas Gas Producer Forecast and Other Forecast

BC hydro
FOR GENERATIONS



Forecast Scenarios

BC hydro
FOR GENERATIONS

- Along with the Reference P50 load forecast, BC Hydro developed a High Scenario and Low Scenario.
- The High Scenario, P50 Forecast and the Low Scenario forecasts each contain different assumptions. The two key adjusted parameters are:
  - the percentage of gas producers that choose to meet their compression needs with electric power
  - different assumptions as to the amount of regional unconventional gas production.

Load Forecast Scenarios

BC hydro
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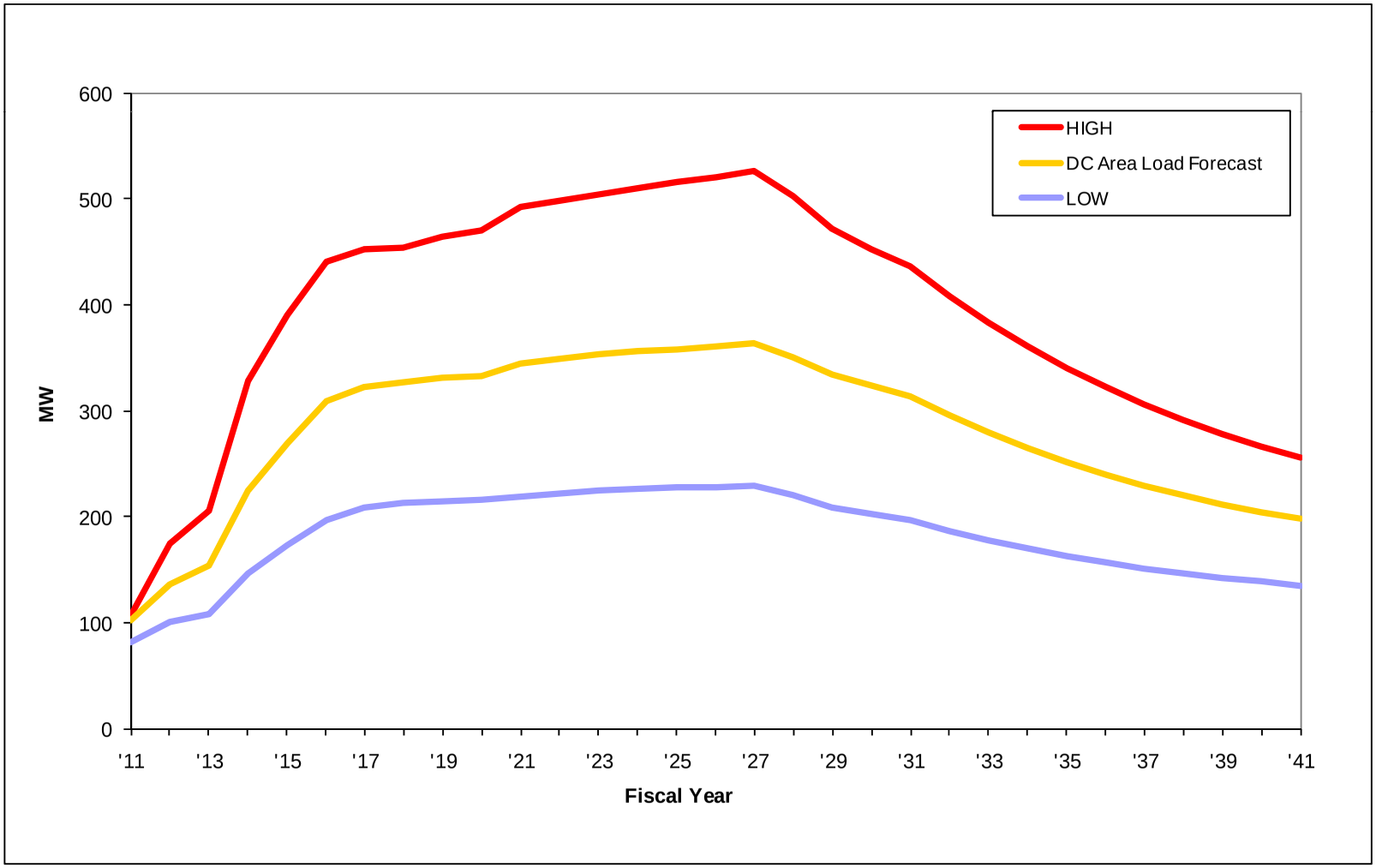

Forecast Risks

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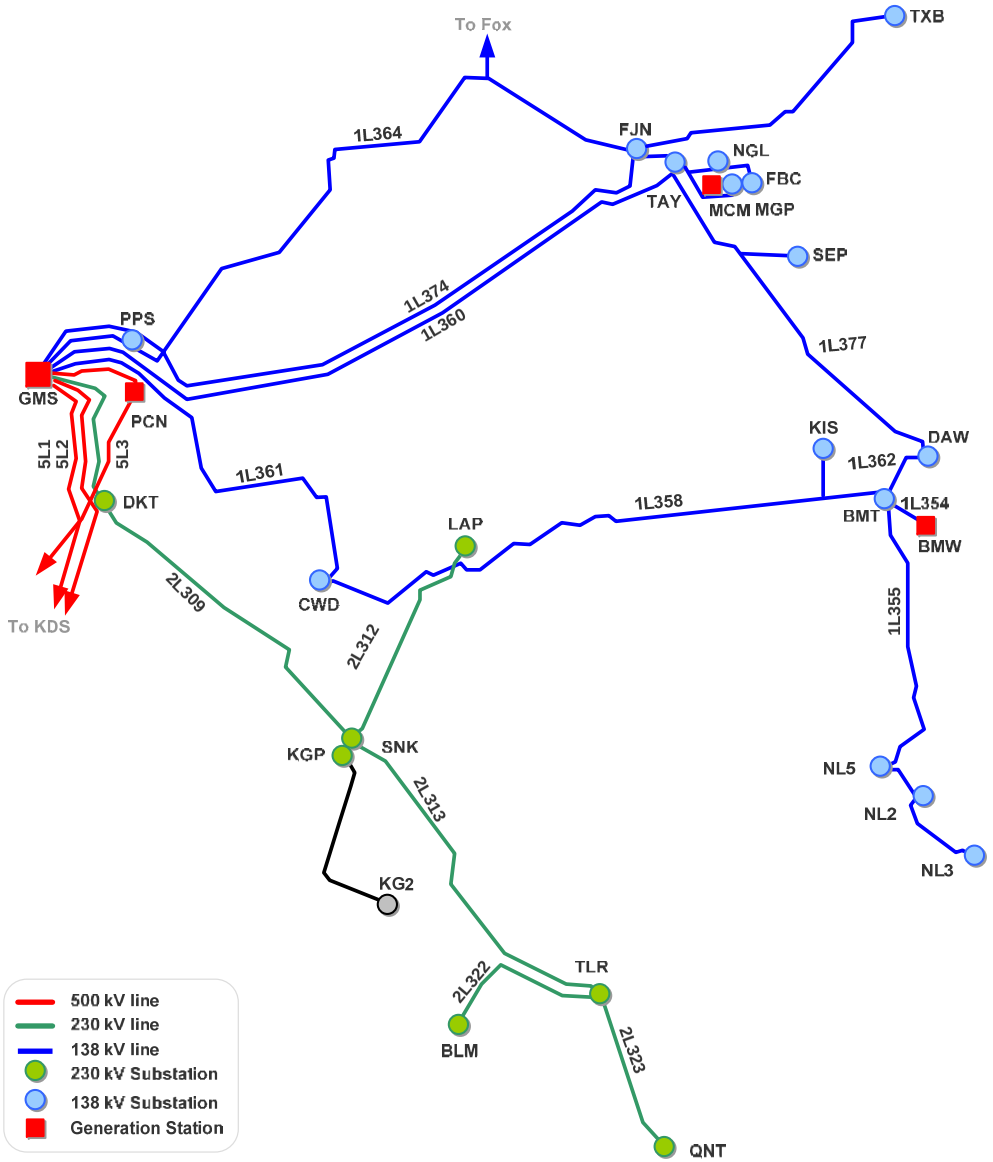
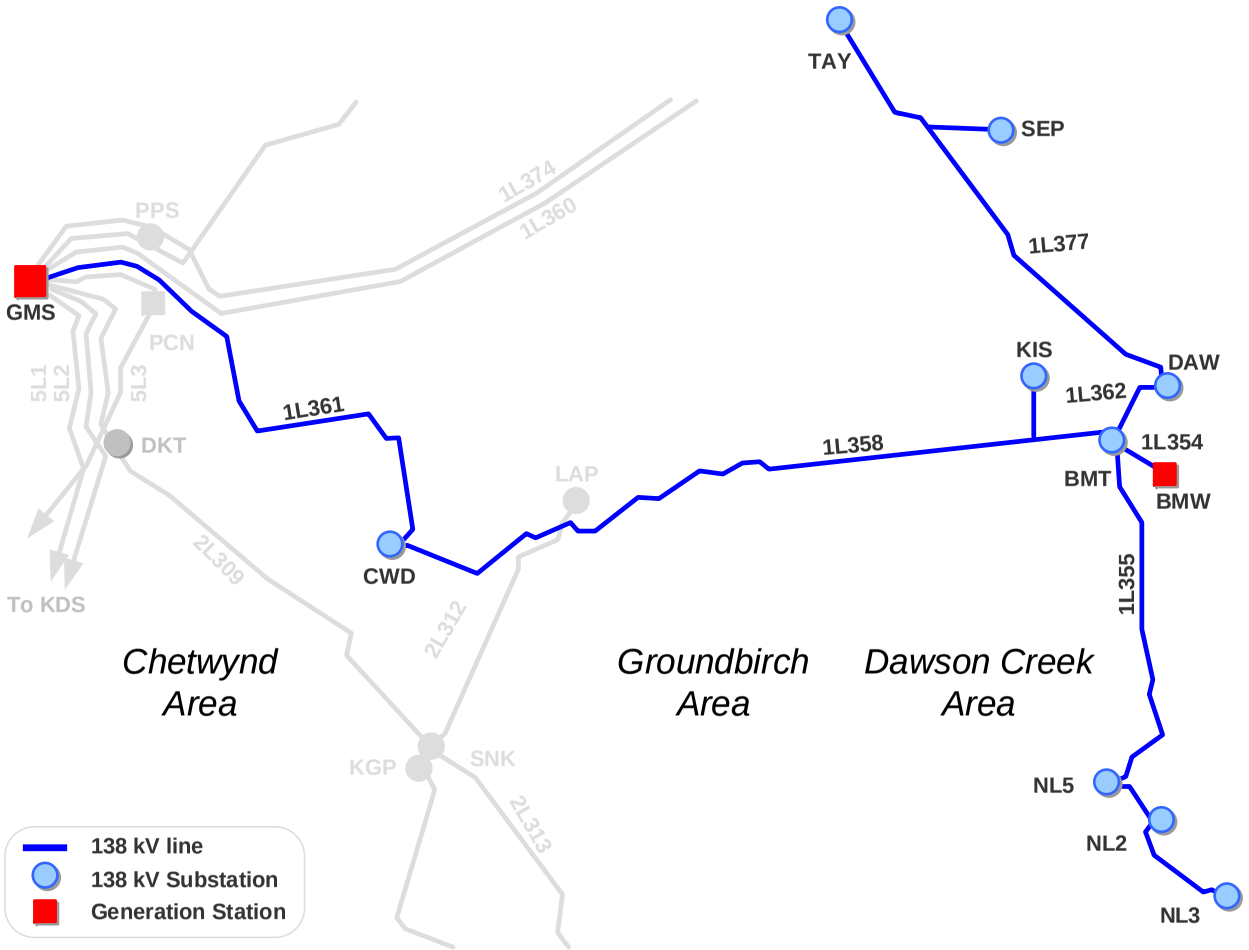
- By far the biggest component of the forecasted load growth is due to electrification of the new regional unconventional gas.
- There is a risk that all gas producers could choose to use gas compressors in which case the load growth could be lower than projected in the Low Scenario forecast.
- This could be caused by a lack of electricity service, changes to the relative cost of fuel prices to the industry (gas vs. Electric Tariff electricity) and carbon pricing.
- Gas production depends on the market price for gas.

Existing Regional Transmission System



Dawson Creek 138kV Transmission System



Existing Regional Transmission System Capacity

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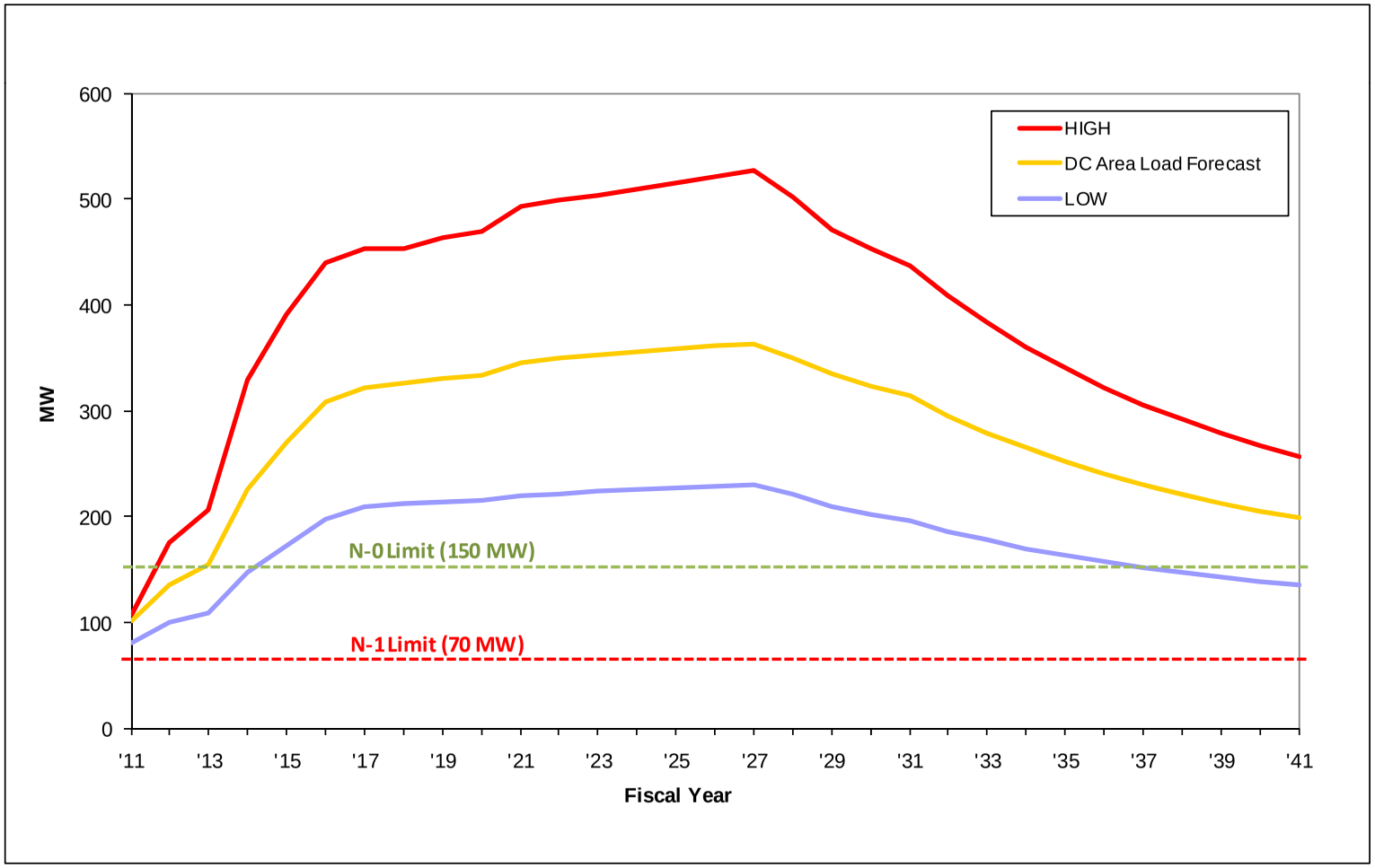

Meeting the 30-year forecast

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FOR GENERATIONS

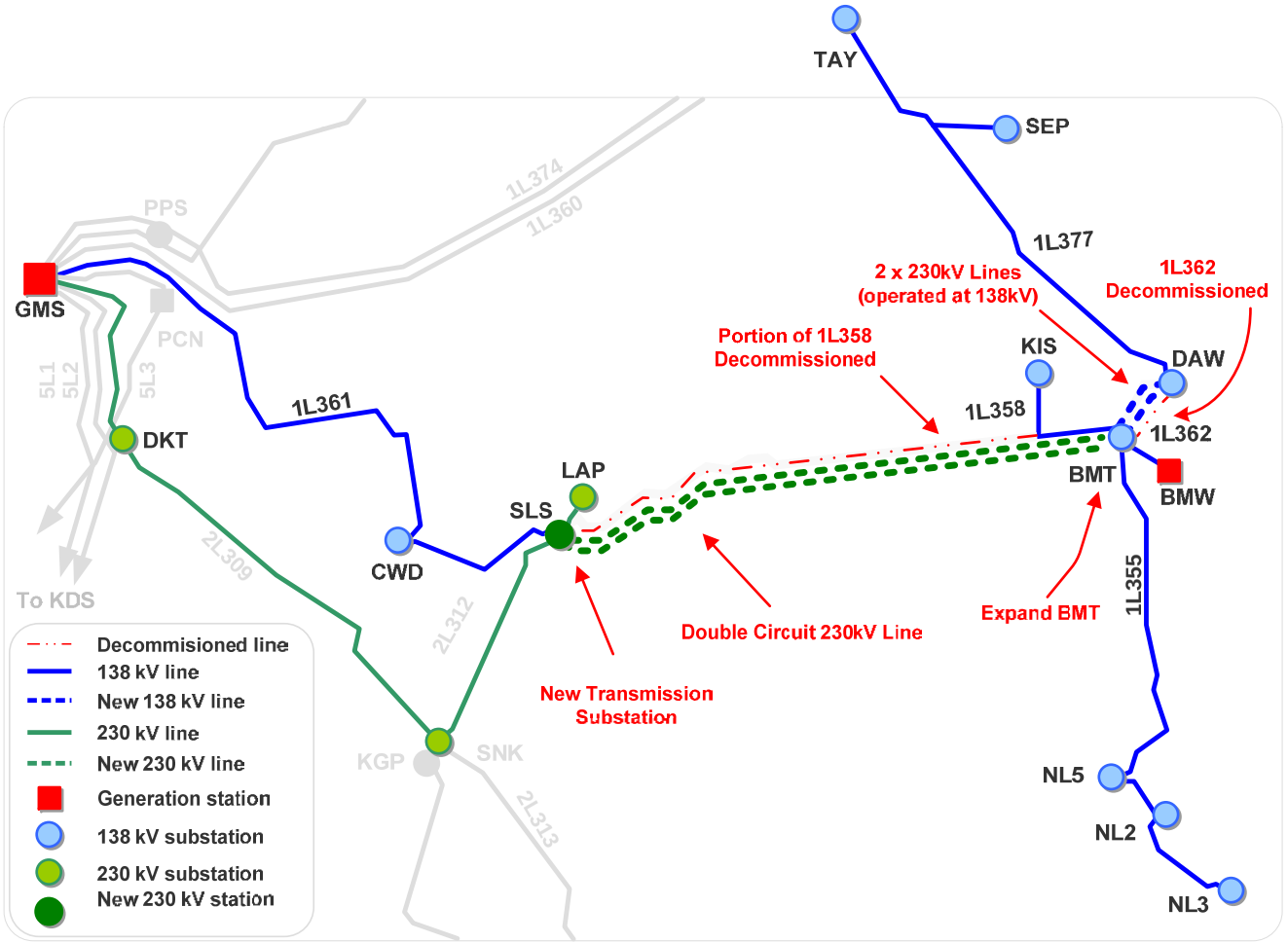
Two Major Projects will be required to meet the 30-year forecast

- First stage in F2014 (DCAT Project)
- Second in F2016 (referred to as “the F2016 stage” for DCAT Project planning purposes)

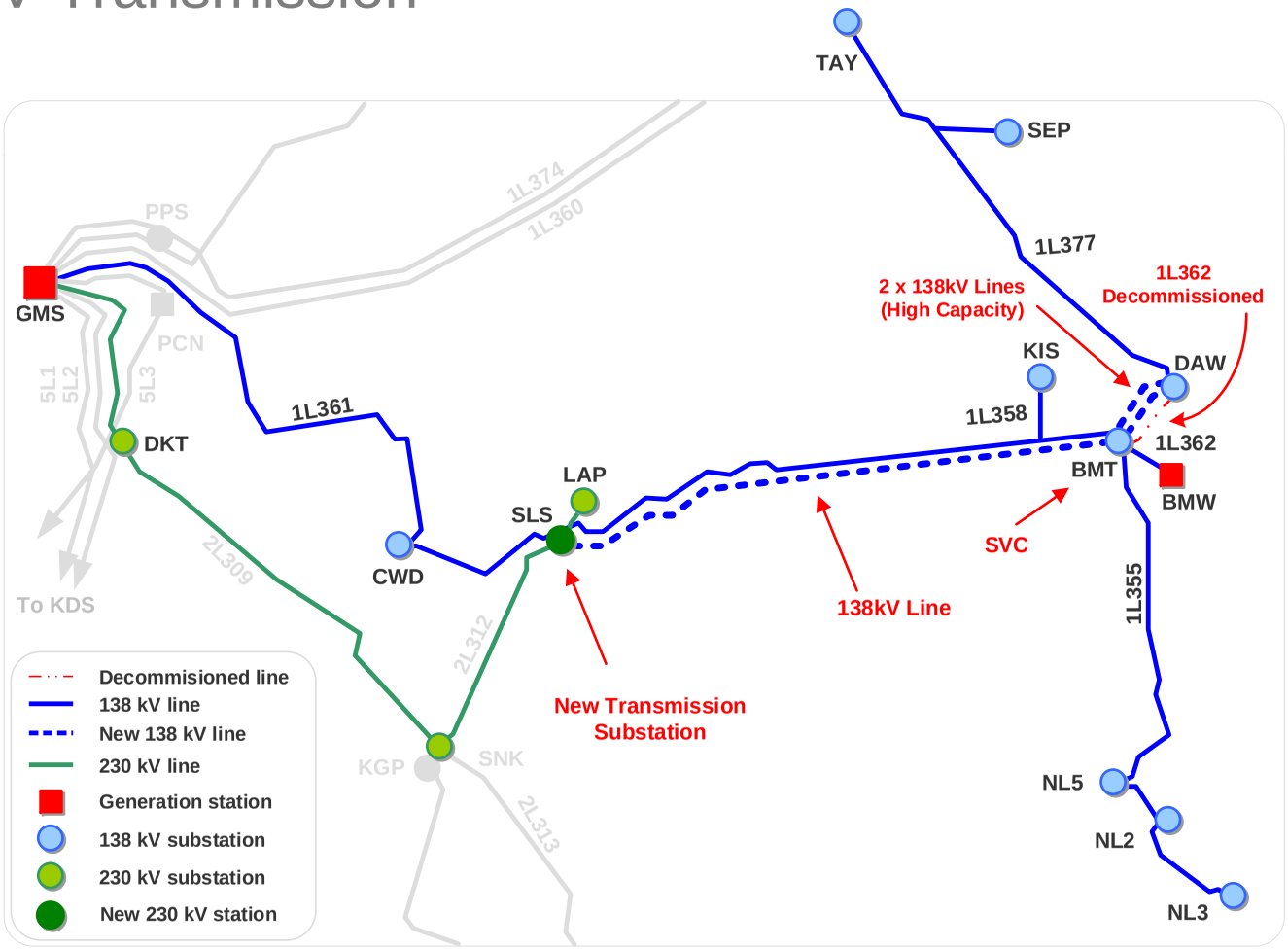
Reason for separating the DCAT Project and the F2016 stage

- DCAT Project necessary to alleviate the current capacity shortfall
- Potential need for F2016 stage has only been apparent after the DCAT had entered the Definition phase.
- DCAT Project should not be delayed to include the F2016 stage because of the immediate need for additional transmission capacity.
- DCAT Project does not impact the alternatives consideration for the later F2016 stage and vice versa.

Alternative 1:
230kV Transmission

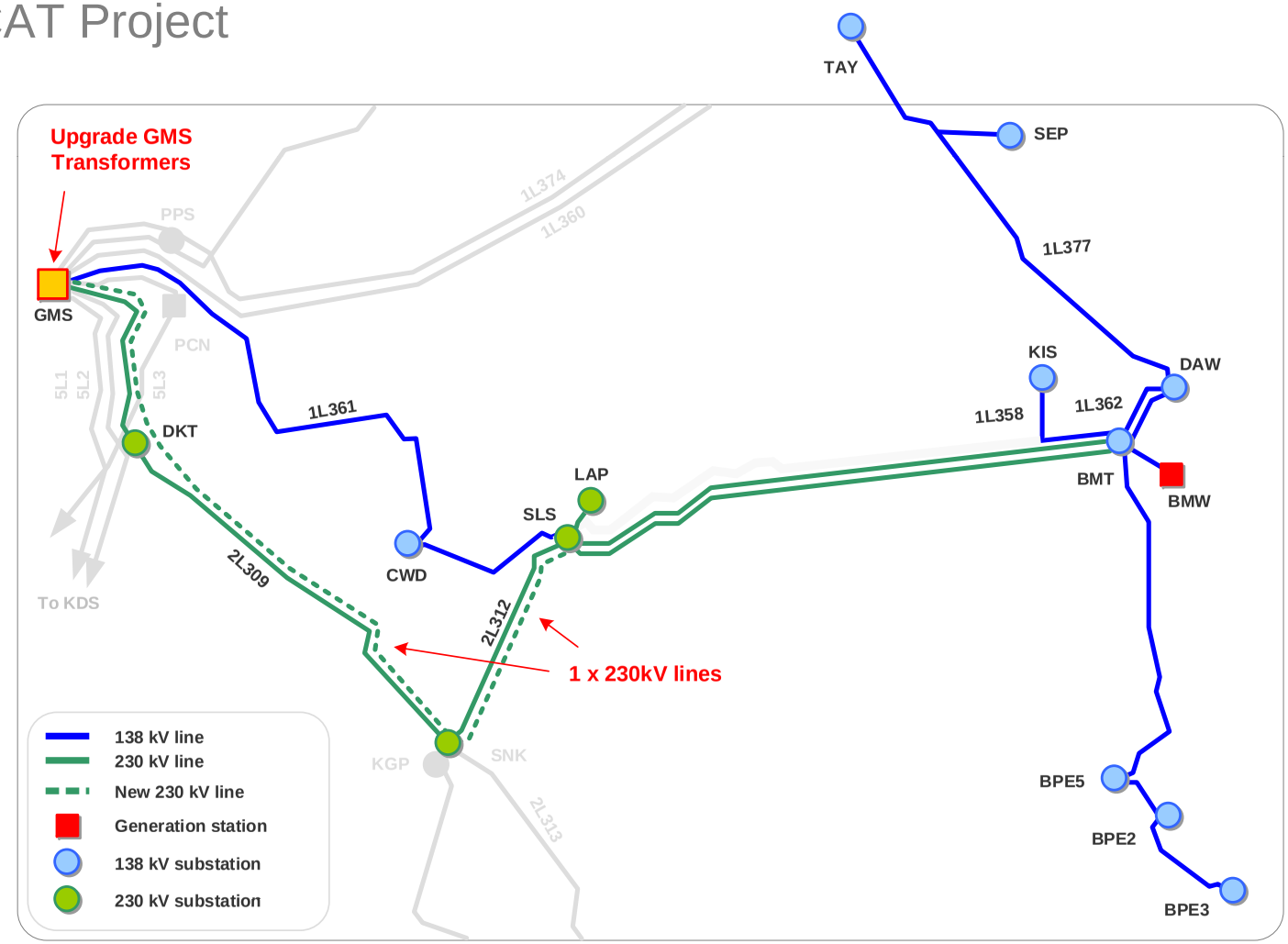


Alternative 2:
138kV Transmission

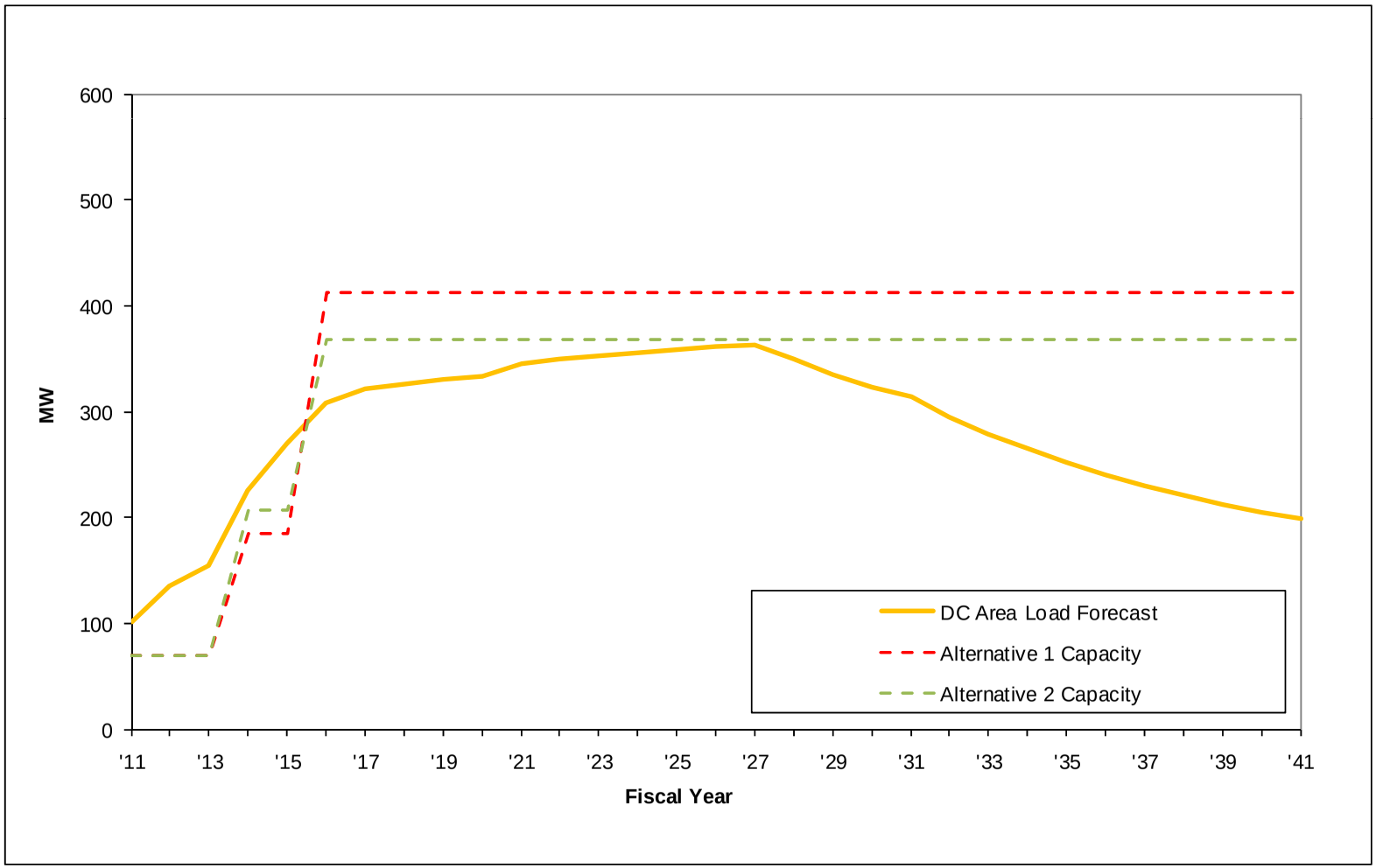


Future Outlook

A F2016 Stage Configuration to allow planning evaluation of the DCAT Project



Alternatives Transmission Capacity



System Planning Evaluation

BC hydro
FOR GENERATIONS

	Alternative 1 230kV Transmission	Alternative 2 138kV Transmission
Direct Capital Cost Planning level estimates	$ 160 M	$ 106 M
Comparative 30-year PV of costs DC Area Load Forecast	$12 M Less than Alt 2	-
Transmission Capacity After DCAT in service	185 MW	205 MW
Transmission Capacity After F2016 stage in service	415 MW	370 MW
Customer Reliability	Best	-
Manage Forecast Uncertainty	Best	-
Manage Point-of-Interconnection Uncertainty	Best	-
System Efficiency	Best	-

Project Description

Based on the system planning evaluation and other considerations, Alternative 1 is the preferred alternative for the Project. The Project is comprised of the following:

a) New 230/138kV substation called Sundance (SLS) located about 19km east of Chetwynd

b) Approximately 60km 230kV double circuit steel pole transmission line from SLS to Bear Mountain Terminal (BMT)

c) Approximately 13km 230kV double circuit steel pole transmission line from BMT to Dawson Creek Substation (DAW)

d) BMT expanded to become a full 230/138kV substation

e) Addition of 138kV equipment at DAW

f) Decommissioning approximately 68km of existing138kv transmission lines that are not required after DCAT is in service

Project in-service date is planned for October 2013

Application Section 4.2

Overview Map of Project

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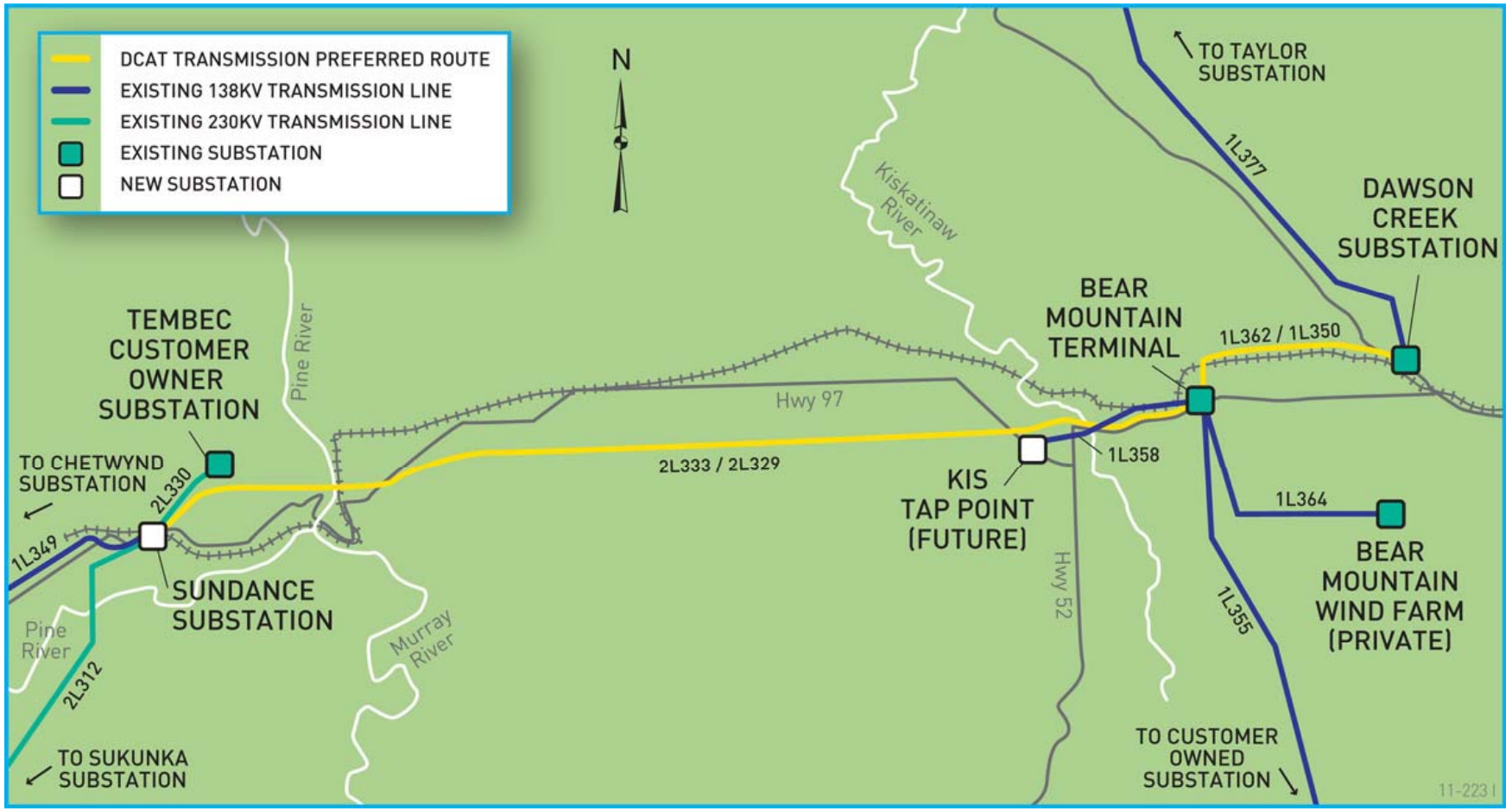

Project Description – Transmission Lines

- Double circuit steel monopoles were selected as the typical structure for the Project
- The average ROW width required for the 230 kV line, at spans of about 300 m to 400 m, would be approximately 33 m
- All trees within the ROW will be cleared, which is estimated to be approximately 130 hectares. One time clearing of additional trees outside of the ROW may also be required during construction.
- Major forest service roads, public and private roads and access trails exist along the route. The preference is to use existing access to the extent feasible.

Application Section 4.3.1

Project Description –Route

BC hydro
FOR GENERATIONS

- Route options were developed within three segments – East, Central, and West. Options were evaluated within each segment.
- The route evaluation is based on a number of objectives, which include minimizing potential impacts to the environment, private landowners, First Nation interests, archaeological sites, project cost, reducing project construction and schedule risk, and maximizing maintainability.
- Statutory ROW over both Crown Land and private land will be required
- Application Section 4.3.2 includes a discussion of the evaluation within each segment

Application Section 4.3.2

Project Description – Substations

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FOR GENERATIONS

Sundance Substation (SLS)

- Proposed 230k/138kV substation located at the intersection of circuits 2L312 and 1L358, 19km east of Chetwynd on south side of Highway 97
- A Crown Grant is required.

Bear Mountain Terminal (BMT)

- Currently a 138kV switching station, BMT is located on the south side of Highway 97 approximately 12 km west of Dawson Creek
- The station requires significant expansion to become a 230kV/138kV substation
- Expansion will be on private land that BC Hydro will acquire; layout options and property discussions are underway

Dawson Creek Substation (DAW)

- Located on the western edge of Dawson Creek, near Highway 97.
- Will be extended and reconfigured to add a 138kV line bay. This work is expected to take place within the existing station fence line.

Application Sections 4.5, 4.6

Project Description - Cost

BC hydro
FOR GENERATIONS

PROJECT COMPONENT - DCAT CONSTRUCTION	AMOUNT ($ million)
Direct Definition Phase Costs	4.1
Direct Construction and Materials Cost	127.7
Project Management, Engineering, Property, Consultation, Environment	28.4
Sub-total: Direct Costs Before Contingency	160.1
Project Contingency on P50 Cost Estimate	28.9
Inflation (Note 1)	9.3
Sub-total: Direct Costs	198.3
Capital Overhead (Note 2)	7.7
IDC (Note 3)	10.9
Dismantling Costs (Note 4)	2.2
Total P50 Cost Estimate	219.1
Incremental Project Contingency (Project Reserve)	32.7
Incremental Capital Overhead due to Project Reserve	1.2
Incremental IDC due to Project Reserve	1.4
Incremental Dismantling Contingency (Reserve) (Note 4)	0.2
P90 Cost Estimate	254.6

Environmental

- An environmental overview assessment was completed to outline the effects and identify mitigation measures for:
  - fish and aquatic resources,
  - soils and vegetation,
  - wildlife,
  - socio-economic,
  - land and resource use, and
  - archaeological resources.
- The EOA concludes that following the implementation of appropriate mitigations, the Project will have a low or negligible effect on almost all the components, except that the residual effect on vegetation is considered moderate in some western portions of the line.
- The mitigation measures and residual effects rating for all disciplines are outlined in Table 5–1 of the Application.
- Prior to construction, BC Hydro will prepare a construction Environmental Management Plan (**EMP**)
  - Contractor(s) will be required to write site specific environmental protection plans (**EPP**) prior to the start of construction.
  - The construction EMP will detail the permitting requirements and best management practices to be implemented during Project construction.

Application Section 5

Electric and Magnetic Fields (EMF)

BC hydro
FOR GENERATIONS

- Based on normal operation during average load, the expected magnetic field for the 230 kV transmission line is approximately:
  - 20.2 mG (directly beneath the conductors)
  - 2.4 mG edge of the ROW of 33 m
  - 0.7 mG 50 m on the side of the operating circuit from the centre line of the transmission line
- This is extremely low in comparison to the International Commission on Non-Ionizing Radiation Protection (**ICNIRP**) guideline limit of 2000 mG.

- Based on normal operation with both 230kV circuits in service, the expected electric field is approximately:
  - 0.5 kV/m at the edge of the ROW
  - less than 0.1 kV/m at a distance of 50 m from the centerline
- This is well below the ICNIRP guideline limit of 5 kV/m

Application Section 5.9

First Nations Consultation

- The Project falls within the boundaries of Treaty 8
- All eight BC Treaty 8 First Nations and the Treaty 8 Tribal Association were notified and continue to be provided information about the Project on an ongoing basis
- The four BC Treaty 8 First Nations closest to the Project were offered funding for the consultation process (Blueberry River First Nation, McLeod Lake Indian Band, Saulteau First Nation, West Moberly First Nations)

First Nations expressed interest in:

- minimizing the use of Crown lands and any expansion of BC Hydro's footprint
- maximizing the use of existing rights of way
- tree clearing and river crossings
- potential impacts to wildlife
- the relationship of the Project to Site C
- procurement opportunities for First Nations

One First Nation identified around the two locations of archaeological interest in the Project area

First Nations Consultation

BC hydro
FOR GENERATIONS

BC HYDRO RESPONSES

- proposed a route located primarily on private lands and parallel to existing transmission lines where possible
- will endeavor to minimize tree clearing
- invited First Nations to participate in the environmental field studies
- provided the Environmental Overview Assessment Report to First Nations for review and comment
- explained that the Project is not related to Site C
- will work with First Nations to identify procurement opportunities
- agreed to conduct an archaeological impact assessment prior to construction if any Project work is identified as occurring on the two locations identified by the First Nation as being of archeological interest

Public Engagement

BC hydro
FOR GENERATIONS

- Public engagement activities included:
  - Letters and notifications;
  - Presentations and meetings;
  - Project website and update information sheets;
  - Newspaper and radio advertisements; published media interviews
  - Public open houses
- Engagement to date has focused on introducing the Project and obtaining feedback – which has included suggestions that were used to develop transmission line routing options, and feedback on the route and stations.
- Project has been presented to Peace River Regional District Board, City of Dawson Creek, local MLA. PRRD and Dawson Creek support the Project.
- Stakeholder consultation has focused on private landowners that are potentially affected by the project
  - Suggestions and feedback from owners influenced the development of BC Hydro's preferred route for the project.
  - Concerns expressed include potential impact on tree screens, agricultural operations

Application Section 6.2

Project Risk and Risk Mitigation

- Need for the Project
  - To minimize the risk that the industrial customer demand does not materialize, BC Hydro has sought sufficient security from new industrial customers.
- Cost of the Project
  - Procurement and Resource Availability Issues
    - Higher than expected bid prices due to uncertainty in steel prices and/or potential for high demand of labour.
    - Project contingency developed using Monte Carlo simulation; procurement plan includes consideration of all procurement issues
  - Construction and Design Related Issues
    - Various issues that could be encountered during detailed design or construction, such as discovery of archeological site, rescheduled system outages, etc.
    - General mitigation measures include adequate contingency planning and schedule flexibility
- Adequacy of the Project
  - BC Hydro is managing the risk that Project is not adequate to meet accelerating load growth by undertaking the Project in a manner that accommodates the consideration of future reinforcements in the area.

Application Sections 7.2-7.4

Project Risk and Risk Mitigation

BC hydro
FOR GENERATIONS

- Timeliness of Project Completion
  - Risk that Project won't be in service in time to meet new loads - steps to mitigate this risk include accelerated ROW acquisition activities and pre-ordering materials where appropriate.
- Safety of the Project
  - Complexity of working in proximity to live high voltage lines.
  - Working next to a busy highway
  - Helicopter stringing work on the major water crossings
- Environmental Impacts of the Project
  - The environmental risks as described in Chapter 5 of the Application are well identified and understood.
  - These risks will be minimized by developing a comprehensive construction EMP, auditing and overseeing contractor work, especially in sensitive areas.
- Table 7–1 in the application summarizes the material risks for the Project, the control and mitigation strategies employed, and the level of risk remaining after implementation of the control and mitigation strategy.

Application Sections 7.5-7.8

Risk Mitigation of Industrial Load

BC hydro
FOR GENERATIONS

- Applying the Electric Tariff provisions to the aggregate load results in no capital contribution requirement from South Peace customers.
- To address stranded investment risk and protect ratepayers BC Hydro is seeking pro-rata security for a portion of the Project costs.
- Capacity will be provided to those presently in the queue.
- Security is required to maintain position in the queue.
- Customer will pay same rates as other customers in the rate class.
- Electric Tariff amendment [distribution] to permit recovery of security for the costs of transmission reinforcements made necessary by aggregate distribution loads greater than 10MW.

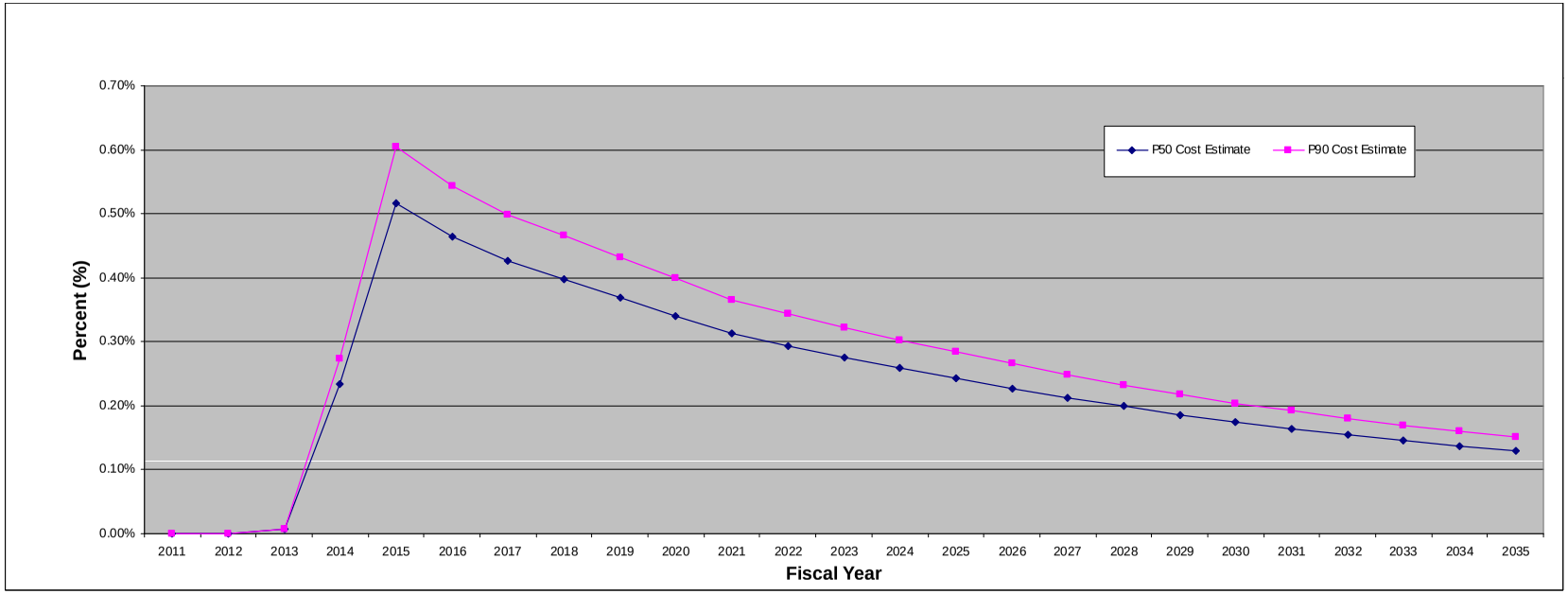
Risk Mitigation of Industrial Customers

BC hydro
FOR GENERATIONS

- DCAT customers with transmission loads over 10MW or aggregate distribution loads over 10MW who are currently in the study (queue) process will be asked to provide security.

- Security will be established for approximately 60% of the Project costs, which represents the incremental capacity available after providing existing customers with adequate capacity to reach the N-1 planning criteria.

Project Description - Rate Impact



Regulatory Timetable

BC hydro
FOR GENERATIONS

Filing of Application	July 11, 2011
BC Hydro hosted Application Workshop	July 20, 2011
BCUC Information Request (**IR**) No. 1	August 10, 2011
BC Hydro responses to BCUC IR No. 1	September 9, 2011
Procedural Conference	September 15, 2011
BCUC IR No. 2 and Intervener IR No. 1	September 23, 2011
BC Hydro responses to BCUC IR No. 2 and Intervener IR No. 1	October 21, 2011
BC Hydro Final Written Submission	November 4, 2011
Intervener Final Written Submission	November 15, 2011
BC Hydro Written Reply Submission	November 25, 2011

BC hydro
FOR GENERATIONS

Questions?

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

APPENDIX B
to Order No. G-132-11
Page 1 of 1

TELEPHONE: 604 660 4700
BC TOLL-FREE: 1 800 663 1385
FACSIMILE: 604 660 1102

An Application by British Columbia Hydro and Power Authority
for a Certificate of Public Convenience and Necessity for the
Dawson Creek/Chetwynd Area Transmission Project

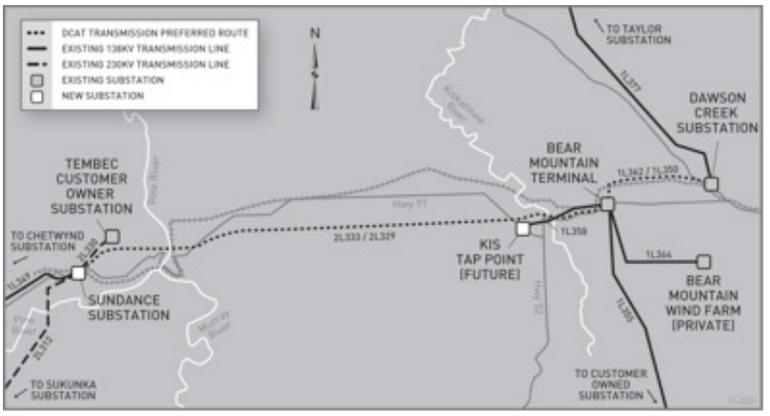
NOTICE OF APPLICATION AND PROCEDURAL CONFERENCE

THE APPLICATION

On July 11, 2011, British Columbia Hydro and Power Authority (BC Hydro) applied to the British Columbia Utilities Commission (Commission) for a Certificate of Public Convenience and Necessity to construct and operate the Dawson Creek/Chetwynd Area Transmission Project.

The Project consists of a new Sundance Substation, expansions of the Bear Mountain Terminal and Dawson Creek Substation and construction of 72 kilometers of double circuit 230 kilovolt transmission line on new or expanded right-of-way. The Project is expected to cost $219.1 million and to go into service in October 2013. A map of the Project is shown on the right.

BC Hydro also requests approval of a revision to its Electric Tariff to require that distribution voltage customers requesting new service in excess of 10 Megawatts provide security for the cost of transmission system reinforcements.



THE REGULATORY PROCESS

Commission Order G-132-11 established an Initial Regulatory Timetable for the review of the Application and a Procedural Conference on Thursday, September 22, 2011, commencing at 9:00 a.m. in the Commission's Hearing Room, Twelfth Floor, 1125 Howe Street, Vancouver, BC. The regulatory timetable can be reviewed on the Commission's website at: **http://www.bcuc.com>Proceedings&Agendas>Current Applications.**

INTERVENTIONS

Persons who expect to actively participate in the BC Hydro proceeding should register as Interveners with the Commission, in writing or electronic submission, by Monday, August 15, 2011. Interveners should state the nature of their interest in the Application, and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process. Interveners will receive a copy of the Application as well as all correspondence and filed documentation and should provide an email address if available.

Persons not expecting to actively participate in the BC Hydro proceeding, but who have an interest in the Application, should register as Interested Parties with the Commission, in writing or electronic submission, by Monday, August 15, 2011, identifying their interest in the Application. Interested Parties will receive a copy of the Introduction of the Application and a copy of the Commission's Decision when issued.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's web site.

PARTICIPANT ASSISTANCE/COST AWARDS

Any party intending to apply for a Participant Assistance Cost Award (PACA) must submit its PACA budget, pursuant to the PACA Guidelines attached to Order G-72-07, to the Commission by Monday, October 3, 2011. The PACA Guidelines are available at the Commission's web site:

http://www.bcuc.com/Documents/Guidelines/Participant/Guide.pdf

PUBLIC INSPECTION OF THE DOCUMENTS

The Application, together with any supporting materials, will be made available for inspection at the following locations:

British Columbia Hydro and Power Authority Regulatory Compliance & Filings 16th Floor – 333 Dunsmuir Street Vancouver, BC V6B 5R3 Web: www.bchydro.com	**British Columbia Utilities Commission** Sixth Floor, 900 Howe Street Vancouver BC V6Z 2N3 Telephone: 1 800 663 1385 Web: www.bcuc.com

FURTHER INFORMATION

For further information, please contact the Acting Commission Secretary, Ms. Alanna Gillis as follows:

Telephone: 604 660 4700 Facsimile: 604 660 1102
B.C. Toll Free: 1 800 663 1385 E-mail: commission.secretary@bcuc.com

3011

Size: 8.32" x 154 lines, black/white: Business section
Paper: Chetwynd echo (PMCP)
Publish: July 29

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

WMFN notes that at numerous places in the Application and supporting documents, reference is made to VECs and VSCs. These valued elements of the human and biophysical environments are used to guide environmental impact assessments of all scope and scale; they are effectively the foundation upon which baseline data collection, project-related impact estimation, identification of appropriate mitigation measures, and determinations of residual impact significance are based.

WMFN notes that the Application and supporting documents make no reference to any VECs or VSCs related to First Nations use and occupancy in the potentially affected area. For example, at Section 5.6.4, discussion of Trapping, Hunting and Recreational Fishing identifies no Aboriginal rights, interests or values whatsoever. Also, at page 5-9 of Chapter 5, #20 and #21, Table 5-1, while Land and Resource Use and Recreation are identified as VEC/VSC categories, Aboriginal traditional land use is not. 15 specific mitigations are identified for non-Aboriginal land and resource use impacts while Aboriginal traditional land use is not even recognized as a valued component.

As BC Hydro is aware, Aboriginal and Treaty rights, including but not limited to harvesting of resources in our traditional territories, are protected under s.35 of the *Constitution Act, 1982.* The absence of VEC/VSCs recognizing this central consideration is an unacceptable oversight by BC Hydro.

1.8.1 Please provide a description of all methods used by the developer and its consultants to identify the VECs and VSCs most important to WMFN during the course of the EOA. ?

RESPONSE:

BC Hydro sought to obtain information that would assist in identifying the values and resources of importance to WMFN through the consultation process. BC Hydro, not AMEC, undertook the consultation with WMFN. Please refer to the response to WMFN IR 1.13.2 for a summary of BC Hydro's efforts to consult WMFN regarding the planned field studies.

In the absence of information provided by WMFN to BC Hydro, AMEC identified relevant VEC's and VSC's based on their experience and expertise. The VEC/VSCs were selected to represent resources of known sensitivity and value.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

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As BC Hydro is aware, Aboriginal and Treaty rights, including but not limited to harvesting of resources in our traditional territories, are protected under s.35 of the *Constitution Act, 1982.* The absence of VEC/VSCs recognizing this central consideration is an unacceptable oversight by BC Hydro.

1.8.2 It does not appear from the Application that traditional land use, or other practices associated with Aboriginal and Treaty rights, have been identified as a VEC/VSC. What is the justification for the exclusion of this VEC/VSC? Was WMFN involved in the decision to exclude this VEC/VSC?

RESPONSE:

Please refer to the response to WMFN IR 1.8.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

WMFN notes that at numerous places in the Application and supporting documents, reference is made to VECs and VSCs. These valued elements of the human and biophysical environments are used to guide environmental impact assessments of all scope and scale; they are effectively the foundation upon which baseline data collection, project-related impact estimation, identification of appropriate mitigation measures, and determinations of residual impact significance are based.

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As BC Hydro is aware, Aboriginal and Treaty rights, including but not limited to harvesting of resources in our traditional territories, are protected under s.35 of the *Constitution Act, 1982.* The absence of VEC/VSCs recognizing this central consideration is an unacceptable oversight by BC Hydro.

1.8.3 Given the importance of Aboriginal and Treaty rights and associated land use by Aboriginal people, please identify how, in the absence of information on WMFN TLU and TK, BC Hydro can provide assurances to the BCUC and Interveners that its estimation of potential project effects is based on sufficiently credible and comprehensive information.

RESPONSE:

Please refer to the response to WMFN IR 1.10.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

Appendix F (at page 37 of 207) refers to the AMEC EOA as making a determination on a VEC or VSC-specific basis of whether the project may cause impacts that are: a) adverse; b) significant; and c) likely.

1.8.4 Please identify:

1.8.4.1 Why no estimation of the confidence held in each prediction is included; and

RESPONSE:

The EOA was written at a level of detail suitable to inform BC Hydro's decision to proceed with the Project, and to meet the information requirements of the BCUC's CPCN Filing Guidelines. In BC Hydro's view, an estimate of the confidence limits of each prediction is not required for the above purposes. Limits of confidence and more involved analyses are typically applied in more detailed review processes such as CEAA.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

Appendix F (at page 37 of 207) refers to the AMEC EOA as making a determination on a VEC or VSC-specific basis of whether the project may cause impacts that are: a) adverse; b) significant; and c) likely.

1.8.4 Please identify:

1.8.4.2 How such a determination can be made for any WMFN traditional use VEC/VSC in the absence of actual studies to establish value and use of the area in question by the WMFN?

RESPONSE:

Please refer to the response to WMFN IR 1.8.4.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.5 Please clarify how criteria (g) was utilized in VEC/VSC determination for vegetation and soils.

RESPONSE:

No species and ecosystems of cultural, social or economic importance were identified that were not already being considered. Criteria (g) is one of a series of criteria employed to identify VEC/VSC. Application of criteria (g) did not add to the VEC/VSCs for vegetation and soils.

Please refer also to the response to WMFN IR 1.8.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.6 Please clarify whether and how criteria (g) was used in the determination of other VECs/VSCs for:

1.8.6.1 Wildlife

RESPONSE:

As noted in the response to WMFN IR 1.8.5, criteria (g) is one of a series of criteria. Application of criteria (g) did not expand the list of wildlife VEC/VSC beyond those already identified by the other criteria.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.6 Please clarify whether and how criteria (g) was used in the determination of other VECs/VSCs for:

1.8.6.2 Aquatic resources (water quality and quantity, fish)

RESPONSE:

Criteria (g) was not applicable to aquatic resources. VECs for fisheries and aquatic resources are discussed in Exhibit B-1, Appendix F, sections 4.2.4 (page 43 of 207) and 4.3.6 (page 52 of 207). Potential VECs and the reasons for their inclusion or exclusion are summarized in Appendix F, Table 4-6 (pages 52 to 54 of 207).

Surface water quantity and quality were selected as they have important community and ecological functions, so it is essential to determine how the Project could affect them. In addition, bull trout and lake chub were selected as VECs to act as umbrella/indicator species for all fish found in the study area.

Please refer also to the response to WMFN IR 1.8.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.6 Please clarify whether and how criteria (g) was used in the determination of other VECs/VSCs for:

1.8.6.3 Traditional and current Aboriginal land use

RESPONSE:

Information regarding traditional and current Aboriginal land use was sought by BC Hydro through the consultation process, not by AMEC as part of the EOA. Please refer to the response to WMFN IR 1.8.1.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.7 Please clarify:

1.8.7.1 Whether and how the WMFN was consulted in the determination of what constitutes a "species or ecosystem of cultural, social, and / or economic importance"; and

RESPONSE:

Please refer to the responses to WMFN IRs 1.8.1 and 1.13.2.

8.0 Reference: Valued Ecosystem Components (VECs) and Valued Social Components (VSCs)
Exhibit B-1, Chapter 5, Section 5.6.4, p. 20

At page 66 of 207 of Appendix F (Section 5.2.4), it is stated that one of the criteria used to determine vegetation and soils VECs is "g) Species and ecosystems of cultural, social, and / or economic importance." Yet subsequently there are no species of importance to First Nations for commercial, subsistence, ceremonial or medicinal reasons identified as VECs here or in Section 5.3 of the main Application document.

1.8.7 Please clarify:

1.8.7.2 How determinations were made by BC Hydro and its consultants of what constitutes a "species or ecosystem of cultural, social, and / or economic importance".

RESPONSE:

The VECs and VSCs were selected to be inclusive and to reflect the range of environmental and social values observed in the literature, in the field studies, and personal communications as referenced at Exhibit B-1, Appendix F, section 11.2 (page 197 of 207).

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.1 Please identify all methods used by the developer and its consultants to understand historic and current values of the WMFN associated with use of, and occupancy within, the area proposed for the DCAT project.

RESPONSE:

The method used by BC Hydro to seek information from WMFN to understand historic and current values of the WMFN associated with the use of, and occupancy within the area proposed for the DCAT project (including previous traditional land use (TLU) and traditional knowledge (TK) reports or other archival materials) was the consultation process starting in March 2010. Please refer to the response to WMFN IR 1.7.1 for a summary of BC Hydro's efforts to consult with WMFN from inception to present.

BC Hydro considers that WMFN is the custodian of the information regarding:

- **WMFN land use and practice of Treaty rights on private lands in the area of the Project for hunting, collection of materials, and other rights based practices; and**

- **the extent to which private lands provide important habitat or corridors for resources or animals, including moose, caribou, fish, birds and other species, upon which WMFN land use and rights, on both Crown and private lands, depend.**

BC Hydro has sought to obtain access to this information through its consultation efforts with WMFN. Please refer to the response to BCUC IR 1.9.2 for the information received to date by BC Hydro from WMFN, through the consultation process, regarding its traditional and current land use and occupancy.

BC Hydro, not its consultant AMEC, is responsible for carrying out the consultation process. Please refer to the response to WMFN IR 1.8.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.2 Please identify all information collected by the developer and its consultants specific to WMFN land use and occupancy in the transmission corridor and its surroundings, including sources of this information.

RESPONSE:

Please refer to the response to WMFN IR 1.9.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.3 Please identify all of the previous TLU/TK reports or other archival materials used to determine WMFN land use and occupancy in the study area for the proposed DCAT.

RESPONSE:

Please refer to the response to WMFN IR 1.9.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.4 Please indicate what specific meaningful traditional and current land use and occupancy information BC Hydro has received through consultation with WMFN and how BC Hydro has made changes to the Project, or otherwise responded, to the provision of information regarding current or planned practice of rights, interests and use by WMFN.

RESPONSE:

Please refer to the response to WMFN IR 1.9.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.5 Does BC Hydro have access to information regarding WMFN land use and rights practice that can confirm the extent to which WMFN members currently use private lands in the area of DCAT for hunting, collection of materials, and other rights based practices?

RESPONSE:

Please refer to the response to WMFN IR 1.9.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.6 Does BC Hydro have access to information regarding the extent to which private lands provide important habitat or corridors for resources or animals, including moose, caribou, fish, birds and other species, upon which WMFN land use and rights, on both Crown and private lands, depend?

RESPONSE:

Please refer to the response to WMFN IR 1.9.1.

9.0 Reference: First Nations Land Use and Occupancy
Exhibit B-1, Chapter 6, Section 6.1.5.2, pp.12, 13
WMFN Land Use and Occupancy in the Study Area
NOTE: In addition to BCUC IR #5

"The transmission corridor passes through primarily privately owned farm land with flat to rolling pastures terrain. In total, 80 percent of the transmission line will be located on private land and 20 percent on Crown Land." (p. 12)

1.9.7 Please identify what efforts BC Hydro will make moving forward to gather meaningful traditional and current WMFN land use and occupancy information and the expected timelines and costs associated with this information collection.

RESPONSE:

Please refer to the responses to BCUC IRs 1.9.1 and 1.13.4.1 and WMFN IR 1.5.1.

10.0 Reference: Adequacy of Consultation
Exhibit B-1, Chapter 6, Section 6.1.7, p. 25
Adequacy of Consultation
NOTE: Related to BCUC IR#13, specific to WMFN

"BC Hydro has concluded that the consultation and, where appropriate, accommodation undertaken in connection with the Project has been adequate to support its decision to file this application for a CPCN. The information obtained from the consultation process has permitted BC Hydro to make its decision honourably, having regard to the Crown's obligation to Aboriginal people."

1.10.1 Please identify whether, and if so, why, the developer feels enough information has been collected to date to properly describe WMFN land use in the study area for the purposes of providing the BCUC adequate information upon which to base its decision-making, and to constitute an information base upon which Crown consultation with WMFN can be meaningfully conducted.

RESPONSE:

BC Hydro concluded that consultation was adequate to support its decision to file the Application based on its assessment of the scope of the duty to consult and its efforts to consult with First Nations. Specifically, BC Hydro ensured that information received from First Nations and all other relevant information relating to First Nation traditional use of the land or exercise of Treaty rights were considered in the context of the decision to file the Application and has put all that information before the BCUC.

BC Hydro believes that the opportunities it has provided for First Nation input, coupled with the use of the information BC Hydro has collected itself is sufficient to provide the BCUC with confidence that it has an adequate base for its decision making. BC Hydro notes the BCUC will also have the benefit of any additional information adduced through its own process.

11.0 Reference: Study Area(s)
Exhibit B-1, Appendix F, p. 41 of 207
Determination of Appropriate Local and Regional Study Areas

No consistent description of local and regional study areas is provided in the Application documents. For example, the EOA refers to Regional and Local Study Areas at page 41 of 207, but then does not use these geographic scopes consistently throughout Appendix F. This lack of consistency makes it extremely difficult to determine the adequacy or accuracy of baseline data collection, let alone the estimation of project effects.

1.11.1 Please identify what study area(s) the developer has used or proposes to use for the purposes of collecting baseline information and estimating impacts of the proposed DCAT project on WMFN land use and occupancy, including meaningful exercise of Aboriginal and Treaty rights.

RESPONSE:

WMFN has not provided BC Hydro with land use information. Please refer to the response to WMFN IR 1.5.1.

11.0 Reference: Study Area(s)
Exhibit B-1, Appendix F, p. 41 of 207
Determination of Appropriate Local and Regional Study Areas

No consistent description of local and regional study areas is provided in the Application documents. For example, the EOA refers to Regional and Local Study Areas at page 41 of 207, but then does not use these geographic scopes consistently throughout Appendix F. This lack of consistency makes it extremely difficult to determine the adequacy or accuracy of baseline data collection, let alone the estimation of project effects.

1.11.2 Please identify the buffers BC Hydro has used around the immediate project footprint for the assessment of other disturbances (e.g. sensory – sight, smell) for each VEC/VSC identified.

RESPONSE:

The Project did not define the corridors and then add buffers. Rather it started with a broad regional desktop study area and then focused in on a Local Study Area (LSA), defined by the actual alignments for the proposed transmission corridor options and a Regional Study Area (RSA) defined by the outer approximate 500 m boundary north and south of the alignment options. The RSA was delineated to reflect an area anticipated to provide habitat for wildlife species that may come in contact with proposed project infrastructure during the course of a season or lifetime. The RSA was chosen after disturbances to flora and fauna for the area were reviewed based on the data collected by other disciplines (e.g., land use and socioeconomic).

No specific buffers for VECs were provided. Impacts of the Project on all VECs were assessed and mitigated over the likely area of Project effects.

Sensory issues were addressed in the EOA (Exhibit B-1, Appendix F): for wildlife, in section 6.5, pages 120 to 122 of 207; and for land use, in section 8.5, pages 159 to 160 of 207. Proposed transmission line upgrades and the substation sensory effects to VECs and their habitats were assessed for construction and operations impacts of the Project. Mitigations were also provided. Sensory effects considered include, noise and vibration from traffic, construction equipment, human activity, and odours of food wastes from construction crews. Potential Project-related effects considered also included alteration of land cover during construction, sensory impacts from habitat alteration and fragmentation, disturbance and/ or displacement, access management and mortality.

11.0 Reference: Study Area(s)
Exhibit B-1, Appendix F, p. 41 of 207
Determination of Appropriate Local and Regional Study Areas

No consistent description of local and regional study areas is provided in the Application documents. For example, the EOA refers to Regional and Local Study Areas at page 41 of 207, but then does not use these geographic scopes consistently throughout Appendix F. This lack of consistency makes it extremely difficult to determine the adequacy or accuracy of baseline data collection, let alone the estimation of project effects.

1.11.3 Please identify the study areas (local and regional) used for any TLU/TK work used to inform the project planning to this point.

RESPONSE:

The study area for Blueberry River First Nation's Traditional Use Study (TUS) was the same area proposed by BC Hydro to WMFN in March 2011, namely "…an area extending 7 km on either side (north and south) of an existing transmission line (1L362) between Dawson Creek and approximately 21 km east of Chetwynd…."

No other TUS was done for the Project.

12.0 Reference: Potential Impacts on Aboriginal and Treaty Rights

1.12.1 Please clarify the total area likely to be physically disturbed by construction and operations activities along the entire route, for all alternatives, and including access points, temporary work sites, linear developments and substations. Then, for the preferred alternative, identify any plans, policies or programs the developer commits to in relation to minimizing net loss of meaningful use of traditional harvesting territory utilized or potentially utilized by area First Nations, as protected under s.35 of the *Constitution Act, 1982*.

RESPONSE:

The table below shows the approximate areas for right of way clearing required for each of the route options evaluated in the EOA.[1] These areas do not include clearing required for access points or temporary work sites, as these will only be determined during detailed design. The table also does not include the disturbance to already cleared lands, such as where access tracks or foundations may need to be installed.

Route Option	E1N	E1S	E2	E3	C1	C3	W1	W2
Cleared Area (ha)	14.7	13.5	8.1	6.3	94.6	122.2	23.9	24.1

The clearing required for Bear Mountain substation is approximately 6 hectares, and Sundance substation is approximately 5 hectares. Please refer to Exhibit B-1, Appendix F, pages 26 and 28.

Please refer to the response to BCUC IR 1.9.2 for a discussion of the mitigation measures related to identified impacts on treaty rights arising from the Project.

[1] **Option C2 was not formally evaluated in the EOA. Please refer to Exhibit B-1, Appendix F, section 2.1, page 21 of 207.**

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.1 Are there any studies on impact of the lines and right of way openings themselves on large mammals in terms of population health, movement and avoidance patterns, disturbance range, and predation effects that have been considered by the developer in it is project planning?

RESPONSE:

BC Hydro did not consider any studies on impacts of the lines and right of way openings themselves on large mammals in terms of population health, movement and avoidance patterns, disturbance range, and predation effects because the transmission lines are expected to have little impact on the existing landscape.

The Pine and Kiskatinaw River corridors, which are among the most continuous tracts of forest in the study area, have already been fragmented through forestry, farming and development. As such, Project impacts are expected to be negligible to large mammal population health, movement and avoidance patterns as the existing transmission corridor is present in an existing fragmented landscape that is already heavily modified.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.2 Was WMFN consulted about wildlife distribution, population health, movements, and potential increased risks on wildlife from the proposed development?

RESPONSE:

On March 3, 2010, BC Hydro sent a letter to WMFN introducing the Project, and advised that it would be undertaking environmental and archaeological studies and that opportunities would be made available for WMFN to participate in these studies. Exhibit B-1, Appendix G, pages 10 to 11.

On May 18, 2010, BC Hydro sent a follow-up letter to WMFN that also referred to the planned environmental studies. Exhibit B-1, Appendix G, pages 21 to 22.

On June 3, 2010, BC Hydro gave a presentation to WMFN on the Project, including information on the planned studies (archaeology, fish and aquatic, wildlife and vegetation) and opportunities to participate in those studies. Exhibit B-1, Appendix G, page 33. At the meeting WMFN identified concerns related to potential impacts to wildlife (fragmentation, wildlife corridors, and a wetland area used by moose) and indicated that it would want to review the results of the studies. Exhibit B-1, Chapter 6, page 17.

On June 10, 2010, BC Hydro sent an email to WMFN following up on the planned studies and the invitation to participate in those studies. A summary of the planned field studies was attached for WMFN review, including information specifically regarding the archaeology, fisheries and aquatics, wildlife and vegetation studies. Exhibit B-1, Appendix G, pages 37 and 40. BC Hydro did not receive any feedback from WMFN on the summary of planned field studies.

On July 7, 2010, BC Hydro called WMFN to follow-up on email of June 10, 2010 to enquire whether WMFN wished to participate in the field studies, as these were set to commence the following week. WMFN advised that it had no staff available. BC Hydro requested WMFN to advise BC Hydro if any field staff did become available as the field work would be continuing through to the end of July, and invited WMFN to raise any questions or concerns regarding the environmental studies. WMFN did not raise any questions or concerns regarding the studies.

On February 8, 2011, BC Hydro met with WMFN and advised that the EOA Report was being drafted and would likely be completed by the end of February. BC Hydro advised it would send a copy of the draft EOA Report to WMFN for review and comment.

On March 10, 2011, BC Hydro sent a copy of the draft EOA Report to WMFN. The cover letter advised that the EOA Report identified potential effects of the Project on wildlife (as well as fish and aquatics, soil and vegetation, human environment, and archaeology) and requested WMFN to review and provide comments on the draft EOA Report. BC Hydro attached a First Nation Comment Form to assist WMFN with its response. Exhibit B-1, Appendix G, pages126 and 130. BC Hydro did not receive any feedback from WMFN on the EOA Report.

Please refer to the confidential Attachment 1 to the response to WMFN IR 1.7.1 for a record of BC Hydro's efforts to consult with WMFN in relation to the Project from inception to present.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.3 Has any WMFN Traditional Ecological Knowledge been incorporated into the assessment of potential project effects on wildlife and if not, why?

RESPONSE:

Please refer to the responses to WMFN IRs 1.8.1, 1.9.1 and 1.13.2.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.4 If hunting is going to be prohibited during construction:

1.13.4.1 Under what authority will the restriction be in place, over what area, applying to whom, and for which species?

RESPONSE:

BC Hydro will restrict Project personnel from hunting on or near the Project. The intent is to ensure safety and to preclude over-harvesting of local wildlife. Hunting limitations will be included in Project contracts.

Hunting limitations will not extend to First Nations or the public although, in the interests of safety, these parties will be asked to avoid hunting in active construction zones.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.4 If hunting is going to be prohibited during construction:

1.13.4.2 How will WFMN hunting practices in the area be affected and accommodated through the construction phase?

RESPONSE:

In the interests of safety, BC Hydro will request that all user groups, including First Nations, not hunt in active construction zones.

The detailed construction schedule is not available at this time. However, the overall duration of construction is approximately 18 months (assumed to begin in May 2012 and end in October 2013) and construction will not be active on all parts of the line at all times.

If WMFN advises BC Hydro when and where its traditional hunting practices could be affected by construction, then BC Hydro will work with WMFN to identify and implement strategies to minimize disruption to those traditional hunting practices.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.4 If hunting is going to be prohibited during construction:

1.13.4.3 How will WMFN travels on the land in the area be affected during and after construction?

RESPONSE:

In most cases, access to the land in the area of the transmission line will still be possible during construction, except at active construction sites and while the conductor is being strung.

Following construction, access to the land in the area of the transmission line will not be affected.

If WMFN advises BC Hydro where and when its travels on the land for the exercise of its treaty rights could be affected by active construction sites and/or while the conductor is being strung, then BC Hydro will work with WMFN to identify and implement strategies to minimize any impacts to the exercise of their treaty rights.

13.0 Reference: Impacts on Wildlife and their Mitigation
Exhibit B-1, Chapter 5, Section 5.1, Table 5.1
Prohibitions on Hunting

The developer's only identified mitigation to protect large mammals is to prohibit hunting during project construction.

1.13.4 If hunting is going to be prohibited during construction:

1.13.4.4 How will WMFN access to harvesting and other use areas proximate to the proposed DCAT project be protected throughout the life of the project?

RESPONSE:

The Project is not expected to have any long term impacts to access to the area proximate to the Project.

If WMFN advises BC Hydro when and where it practices traditional harvesting and other traditional use practices proximate to the Project area, then BC Hydro will work with WMFN to identify and implement strategies to protect WMFN traditional harvesting and other traditional use practices throughout the life of the Project.

14.0 Reference: Baseline Information and Impacts on Wildlife – Species at Risk
Exhibit B-1, Appendix F

1.14.1 How was WMFN traditional knowledge used to inform the gap analysis for endangered species and to identify potential habitats and historical distributions?

RESPONSE:

WMFN traditional knowledge was not used to inform the gap analysis. Please refer to the response to WMFN IR 1.8.1.

Please refer to the response to WMFN IR 1.13.2 for a summary of the opportunities provided to WMFN through the consultation process to review, comment on and participate in the environmental field studies, including the wildlife survey.

14.0 Reference: Baseline Information and Impacts on Wildlife – Species at Risk
Exhibit B-1, Appendix F

1.14.2 Has the proponent worked with WMFN to determine whether other endangered species, and particularly caribou, were historically present in the study area?

RESPONSE:

BC Hydro has not worked with WMFN to determine whether endangered species, particularly caribou, were historically present in the area.

To date, the only communication received by BC Hydro from WMFN regarding the Project that mentions caribou is WMFN's letter dated July 18, 2011, which contains references to planning decisions WMFN has made regarding harvesting caribou. WMFN has not provided any information suggesting a link between the Project and caribou survival or abundance and BC Hydro's own work has identified none.

Please refer also to the responses to WMFN IRs 1.8.1 and 1.13.2.

14.0 Reference: Baseline Information and Impacts on Wildlife – Species at Risk
Exhibit B-1, Appendix F

1.14.3 Linear features continue to be a factor in caribou declines in BC. In light of the recent BC Court of Appeal finding in *West Moberly First Nations v. British Columbia (Chief Inspector of Mines)*, 2011 BCCA 247, regarding caribou recovery in the region, and given the recent efforts on behalf of the WMFN to ensure protection of current and potential caribou habitat in the region, how has the proponent worked with First Nations and the caribou recovery teams to address the risk of impacts from the Project (ie. linear development) and subsequent shale gas development on potential caribou recovery in the region?

RESPONSE:

Please refer to the response to WMFN IR 1.14.2.

15.0 Reference: General Mitigation Issues
Exhibit B-1, Appendix F, p. 58 of 207
Summary of Mitigation Commitments and Role of WMFN in their Identification

Table 4.9 at page 58 of 207 of Appendix F is one of a series of summary tables in Appendix F that identify "available mitigation strategies" that could be used to avoid, minimize or otherwise mitigate potential project effects. What is not clear to the reader is the degree to which each mitigation strategy has actually been adopted by the developer based on its consultants recommendations, and what mitigation strategies and specific measures the EMP and the contractor-specific EPP's will be required to adopt.

1.15.1 Please provide a summary table listing all mitigation measures, by topic, that BC Hydro commits to adopting for this project, including a reference to where in the Application the commitment is made to adopt the recommended mitigation; and

RESPONSE:

Please refer to the response to BCOAPO IR 1.11.1.

15.0 Reference: General Mitigation Issues
Exhibit B-1, Appendix F, p. 58 of 207
Summary of Mitigation Commitments and Role of WMFN in their Identification

Table 4.9 at page 58 of 207 of Appendix F is one of a series of summary tables in Appendix F that identify "available mitigation strategies" that could be used to avoid, minimize or otherwise mitigate potential project effects. What is not clear to the reader is the degree to which each mitigation strategy has actually been adopted by the developer based on its consultants recommendations, and what mitigation strategies and specific measures the EMP and the contractor-specific EPP's will be required to adopt.

1.15.2 Please provide BC Hydro's plans for vetting the Environmental Management Plan and/or contractor-specific Environmental Protection Plans with affected First Nations, including WMFN.

RESPONSE:

Please refer to the response to WMFN IR 1.17.2.1.

15.0 Reference: General Mitigation Issues
Exhibit B-1, Appendix F, p. 58 of 207
Summary of Mitigation Commitments and Role of WMFN in their Identification

Table 4.9 at page 58 of 207 of Appendix F is one of a series of summary tables in Appendix F that identify "available mitigation strategies" that could be used to avoid, minimize or otherwise mitigate potential project effects. What is not clear to the reader is the degree to which each mitigation strategy has actually been adopted by the developer based on its consultants recommendations, and what mitigation strategies and specific measures the EMP and the contractor-specific EPP's will be required to adopt.

1.15.3 Please provide a table listing all instances where consideration of WMFN use and/or ecological knowledge has contributed to mitigation commitments made by the developer for the proposed DCAT project, including the source(s) of the information by Aboriginal group, that led to the commitment.

RESPONSE:

Please refer to the confidential response to BCUC IR 1.9.2.

16.0 Reference: Archaeological Resources
Exhibit B-1, Chapter 5, Section 5.7
Involvement of WMFN in Archaeological Methods Development and Work

1.16.1 Please indicate:

1.16.1.1 What parameters were used in the AOA to determine low, moderate and high archaeological potential; and

RESPONSE:

The desktop AOA for the Project relied on an existing predictive model for the Peace Forest District (Eldridge et al., 2010). This Model identifies landscapes, or portions of landscapes, that have "high" or "low" potential for archaeological sites. The Model is based on Digital Elevation Measurements (DEM) obtained from TRIM mapping to identify landforms that have characteristics typical of locations where archaeologists tend to find archaeological sites in northeast British Columbia. Because all landforms are not captured in TRIM mapping, users of the Model are cautioned to use other forms of data (aerial photos, small-scale maps, satellite imagery, etc.) to refine their assessment of archaeological potential. Further details are provided in the Environmental Overview Assessment, section 9.2.4 on page 160, and section 9.4.3 on page 167.

A three-day preliminary field reconnaissance was also carried out during the summer of 2010. The purpose of the reconnaissance was to inspect lands within several transmission line route options to evaluate the performance of the AOA and make any refinements to the assessment of archaeological potential. The results of the reconnaissance suggested that an AIA is required along the selected Project route.

16.0 Reference: Archaeological Resources
Exhibit B-1, Chapter 5, Section 5.7
Involvement of WMFN in Archaeological Methods Development and Work

1.16.1 Please indicate:

1.16.1.2 How these parameters were informed by WMFN cultural knowledge (current use, trail information, etc.).

RESPONSE:

The Peace Forest District AOA (Eldridge et al., 2010) includes data provided by several First Nations during the development of the Model. These data are displayed as polygons on maps output by the Model, but do not contain labels or information describing what they represent. The onus is on the user of the Model to contact the relevant First Nation(s) for additional information.

It should be noted that the West Moberly First Nation chose not to participate in the development of the Peace Forest District AOA.

First Nations were invited to participate in the archaeology field study in the summer of 2010. A member from McLeod Lake Indian Band and a member from Saulteau First Nation chose to participate in the fieldwork. West Moberly First Nation advised BC Hydro that no staff were available to participate in the field work. Please refer to the responses to BCUC IR 1.13.3 and WMFN IR 1.13.2.

16.0 Reference: Archaeological Resources
Exhibit B-1, Chapter 5, Section 5.7
Involvement of WMFN in Archaeological Methods Development and Work

1.16.2 Please provide additional information regarding the 'cultural depression' and 'cairn' features reported, and indicate how WMFN was involved in interpreting the potential significance of these features.

RESPONSE:

Archaeological site GkRd-7 is located 380 m north of the selected Project route. The site was identified and recorded in 1976 as part of a large-scale archaeological investigation in advance of coal development. The site was included in the desktop AOA, as it is located within the Regional Study Area (defined in the Environmental Assessment report; AMEC 2010b). The Regional Study Area was selected to review a sample of archaeological sites recorded in the general vicinity of the project. Site forms were obtained from the Remote Access to Archaeological Data (RAAD) application maintained by the Archaeology Branch. Each site form was reviewed to determine what types of archaeological sites can be expected within the project area, as well as to identify the landscapes and landforms on which these sites are located.

Archaeological site GkRd-7 is described as a cairn and a cache pit with pemmican still present. The site form describes the site as disturbed, presumably by agricultural activities. As the site is located outside of the lands affected by the proposed transmission line, significance of the site has not been assessed.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental

management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

Also, Exhibit B-1, Chapter 5, Section 5.8, p. 24

"Generally, BC Hydro's Environmental Officer will be responsible for: (a) Ensuring the further field investigations are conducted, as necessary before construction occurs; (b) Assessing the effectiveness of mitigation measures; (c) Collecting data to confirm mitigation effectiveness; (d) Ensuring compliance with all environmental permits, notifications and approvals; and (e) Halting work if construction activities are contributing to unacceptable environmental impacts."

The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

1.17.1 What binding assurances can the developer give WMFN and the BCUC that any gaps in information and mitigation during regulatory would actually be filled "post-regulatory", such that WMFN concerns will be substantively and meaningfully addressed?

RESPONSE:

Please refer to the responses to BCUC IRs 1.9.1 and 1.13.4.1.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental

management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

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The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

1.17.2 The Application materials refer to an Environmental Management Plan (e.g. in the excerpt above and at Appendix F, Section 2.2.3) and to on-site monitoring. No reference is made to the role of area First Nations in development of same, on-the-ground presence, reporting, or involvement in implementation of management plans. Please clarify:

1.17.2.1 BCH's intent and commitments to having potentially-affected First Nations involved in these stewardship activities on their traditional territories?

RESPONSE:

BC Hydro will provide draft copies of the Environmental Management Plan (EMP) and Environmental Protection Plans (EPP) to First Nations for review and comment. In addition, specifically with respect to WMFN, BC Hydro has made an effort to provide WMFN with an opportunity for early input into initial drafting of the EMP. Please refer to the letter from BC Hydro to WMFN dated September 8, 2011, attached to the response to BCUC IR 1.9.1

If BC Hydro receives feedback from First Nations, including WMFN, on the EMP or EPP, then it will work with those First Nations to incorporate their input, as appropriate, into the EMP and EPP.

In addition, if BC Hydro receives feedback from First Nations, including WMFN, indicating interest in participating in the implementation of the EMP or EPP, then it will work with those interested First Nations to find opportunities for their participation in the implementation of the EMP or EPP.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental

management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

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"Generally, BC Hydro's Environmental Officer will be responsible for: (a) Ensuring the further field investigations are conducted, as necessary before construction occurs; (b) Assessing the effectiveness of mitigation measures; (c) Collecting data to confirm mitigation effectiveness; (d) Ensuring compliance with all environmental permits, notifications and approvals; and (e) Halting work if construction activities are contributing to unacceptable environmental impacts."

The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

1.17.2 The Application materials refer to an Environmental Management Plan (e.g. in the excerpt above and at Appendix F, Section 2.2.3) and to on-site monitoring. No reference is made to the role of area First Nations in development of same, on-the-ground presence, reporting, or involvement in implementation of management plans. Please clarify:

1.17.2.2 What commitments the developer has made to including First Nations in the development of EMPs.

RESPONSE:

Please refer to the response to WMFN IR 1.17.2.1.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental

management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

Also, Exhibit B-1, Chapter 5, Section 5.8, p. 24

"Generally, BC Hydro's Environmental Officer will be responsible for: (a) Ensuring the further field investigations are conducted, as necessary before construction occurs; (b) Assessing the effectiveness of mitigation measures; (c) Collecting data to confirm mitigation effectiveness; (d) Ensuring compliance with all environmental permits, notifications and approvals; and (e) Halting work if construction activities are contributing to unacceptable environmental impacts."

The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

1.17.3 Please identify any commitments by the developer to include WMFN and its members in the management and monitoring of the project during construction, post-construction and operations.

RESPONSE:

The term "post-regulatory" refers to the construction phase of the Project. The Project will conclude when construction is completed and the Project is in-service; therefore there is no post-construction or operations phase of the Project.

BC Hydro will continue to consult with First Nations during the construction phase of the Project. Please refer to the response to WMFN IR 1.17.2.1 for a discussion of BC Hydro's plans to include First Nations during construction.

17.0 Reference: Continued Consultation and Meaningful Engagement of the WMFN Throughout the Project Life Cycle
Exhibit B-1, Chapter 4, Section 4.2.1.6, p. 6
Post-regulatory Engagement and Consultation

"As described in section 5.8, BC Hydro will develop a construction environmental

management plan (**EMP**) that addresses environmental concerns with respect to access requirements and construction within the ROW."

Also, Exhibit B-1, Chapter 5, Section 5.8, p. 24

"Generally, BC Hydro's Environmental Officer will be responsible for: (a) Ensuring the further field investigations are conducted, as necessary before construction occurs; (b) Assessing the effectiveness of mitigation measures; (c) Collecting data to confirm mitigation effectiveness; (d) Ensuring compliance with all environmental permits, notifications and approvals; and (e) Halting work if construction activities are contributing to unacceptable environmental impacts."

The Application also refers in several places to continued consultation with First Nations moving forward "post-regulatory".

1.17.4 Please provide a description of all mechanisms by which the developer will seek to resolve any concerns raised by WMFN in relation to the project, through all phases of the Project life cycle, starting with the current regulatory phase.

RESPONSE:

Please refer to the responses to BCUC IRs 1.9.1, 1.9.2 and 1.13.4.1.