IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
FOR THE
DAWSON CREEK/CHETWYND AREA TRANSMISSION PROJECT

DECISION

October 10, 2012

Before:

L.A. O'Hara, Commissioner/Panel Chair
D.M. Morton, Commissioner
C.A. Brown, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

TABLE OF CONTENTS

Page No.

EXECUTIVE SUMMARY

This is a Decision on an application by British Columbia Hydro and Power Authority (BC Hydro) for a Certificate of Public Convenience and Necessity (CPCN) to construct the Dawson Creek/Chetwynd Area Transmission (DCAT) Project. The Application proposes that the Project is required as soon as possible to resolve constraints in the existing 138 kV transmission system, to serve significant load growth in the Groundbirch and Dawson Creek areas, and to restore reliable service to the region. The industrial load growth is primarily attributable to the development of the unconventional gas reserves (shale gas) in the Montney gas basin.

The Project includes three main components: construction of the new Sundance Lakes Substation, construction of a 60 km double circuit 230 kV transmission line from Sundance Lakes to Bear Mountain Terminal (BMT) Substation and continuing a further 12 km to the Dawson Creek Substation on a new or expanded right-of-way, and the expansion of BMT. The Project is estimated to cost $222 million and has an expected in-service date of April 30, 2014.

The Application also seeks an order to approve a revision to BC Hydro's Electric Tariff. The proposed revision of the Tariff's Terms and Conditions would allow BC Hydro to obtain security for the cost of transmission reinforcement from new distribution customers that seek new service in excess of 10 MW. This change is driven by BC Hydro's desire to treat the five new industrial customers in an equitable manner. Three of the five customers will receive service as transmission customers whereas the other two have opted for distribution service.

The Application has raised a significant amount of controversy among the stakeholders. The causes of controversy might be identified as follows:

i. The need for transmission reinforcement results from dramatic and perhaps unprecedented growth in one relatively confined area of the province, largely driven by a single industry that is not present elsewhere in the province;

ii. The Project is being proposed at a time of major developments in the area both in the natural gas industry and in connection with other BC Hydro projects, such as Site C.

Several key issues emerged during the proceeding and have been addressed by the Panel in this Decision. They include:

- Uncertainty related to the load forecast of the unconventional natural gas sector;
- Risk of stranded assets and/or a underutilized system after 20 years when the new industrial load is forecast to trend down;
- Implications and relevance of the Mandatory Reliability Standards and the "N-1 service standard";
- BC Hydro's obligation to serve and provide competitively priced and reliable power;
- Operation of the Electric Tariff with respect to customer contribution in the case of system reinforcement, including the role of security deposits;
- How Tariff Supplement 6 is interpreted and applied to phased construction projects and projects that have an associated load forecast with significant uncertainty;
- The need for a review of industrial tariffs and rates;
- Adequacy of First Nations' consultation, including cumulative impacts; and
- The subsequent Phase 2 transmission project being planned for the area, described as Greater Dawson Creek Area Transmission or GDAT.

At the request of BC Hydro, the Commission Panel temporarily suspended the review process on November 11, 2011, to give BC Hydro time to address policy-related issues that were not dealt with in the Application. The Commission lifted the temporary suspension on April 11, 2012.

The review of the Application was conducted primarily by way of a written hearing. However, the review of the adequacy of First Nations' consultation was conducted in an Oral Hearing Phase held from July 9 to July 10, 2012. The Commission Panel also participated in a flyover of the proposed DCAT route to gain further perspective.

There was a broad range of Interveners who participated in the review process. The five industrial customers are: Air Liquide Canada, Arc Resources Ltd., Encana Corporation , Murphy Oil Company Ltd. and Shell Canada Ltd. Other Interveners that made submissions included the Ministry of Energy and Mines, the City of Dawson Creek, various industry associations, rate-payer groups, West

Moberly First Nations (WMFN), and landowners Gary and Marilyn Robinson. These parties made a valuable contribution during the review of this Application, which is appreciated by the Panel.

The Commission Panel, after hearing submissions from parties, ruled on issues that relate to the appropriateness of rolled in rate principles and postage stamp rates as well as larger, province wide resource planning issues as being out of scope. Similarly, the appropriateness of the N-1 service standard was ruled out of scope.

A. CPCN Considerations

The Panel finds that a project is required to resolve constraints in the existing 138kV Transmission system in the Dawson Creek area, to serve significant load growth, and to move towards reliable service. However, the Panel is not persuaded that the DCAT Project, while needed, necessarily must be in service by April 30, 2014 because of BC Hydro's ability to implement remedial action schemes/load shedding strategies in response to system contingencies in order to preserve service to the remaining connected loads. Furthermore, four of the five new industrial customers appear to have made temporary arrangements for at least a portion of their respective requirements to manage until the DCAT Project is built.

The Panel considered at length whether the proposed DCAT Project is adequate to meet the N-1 planning standards to which BC Hydro adheres, or whether DCAT must be considered along with the Phase 2 GDAT project. This determination is important, as it may influence whether the Phase 1 DCAT and Phase 2 GDAT are to be assessed independently or together for the purpose of calculating customer contributions and security deposits. Considering the two phases together would mean larger financial commitments by the five new industrial customers. The Panel agrees the GDAT project is necessary to provide N-1 service to those customers that have implemented post-contingency load shedding schemes, but disagrees the Phase 2 is required for compliance with Mandatory Reliability Standards. Accordingly, the Panel determines that with appropriate load shedding agreements the DCAT Project can provide the required reliability regardless of whether the GDAT project is completed in a timely fashion.

The evidence shows a significant difference between two consecutive load forecasts prepared in December 2010 and 2011. While the Panel accepts that BC Hydro has been reasonable in mitigating the load forecast risk or lack of robustness inherent in the sector-specific and region-specific forecast, it notes that the change in input assumptions that results in the increased long term load lacks certainty. The Panel concludes that this uncertainty supports BC Hydro's recommendation to proceed with the Phase 1 only as the recommended Project provides sufficient flexibility regardless whether the actual load is above or below the forecast. Furthermore, the Panel finds that the risks inherent in the single industry forecast emphasize the urgent need for the broad review of industrial tariff, rates and rate design.

The Panel finds that Project Alternative 1, as proposed by BC Hydro, while not the least expensive option, is the most cost-effective transmission reinforcement alternative, as it provides significant flexibility to meet future anticipated growth.

The Panel determines that the Crown's duty to consult with WMFN for the DCAT Project has not been adequate up to the point of this Decision to support issuing the CPCN. Deficiencies were found in the areas of BC Hydro's preliminary assessment of the nature and scope of its duty to consult WMFN and related difficulties with arrangement of study funding, the issue of moose and moose habitat, and the scope of the Environmental Overview Assessment. Furthermore, the possible impact of the Project on the seasonal round which is the practice of WMFN's treaty rights of hunting, fishing and trapping, and consideration of new adverse impacts of the Project with an adequate cumulative impact perspective were identified specifically as deficiencies.

The Commission Panel will grant a CPCN to BC Hydro for the DCAT Project, as set out in the Application, subject to further consultation between WMFN and BC Hydro. BC Hydro is expected to provide further evidence which demonstrates consultation to a medium level on the *Haida* spectrum, addressing the deficiencies outlined in the Decision, no later than 180 days from the issuance of this Decision.

B. Rate and Tariff Considerations for Transmission and Distribution Service

The Panel is not prepared to approve the proposed revision to section 8.3 of the Terms and Conditions of the Electric Tariff at this time. The Panel may be prepared to accept the proposed changes subject to clarification in the area of potential double counting of customer benefits in the calculation of both transmission and distribution offsets as well as certain tariff wording clarifications.

Although the merits and need for the Phase 2 GDAT project are not before this Panel to consider, the potential for it to proceed in the near future has raised concerns in the rate and tariff context.

As changes to tariffs can have implications to customer groups extending beyond the current and future Dawson Creek area customers this Panel, having the benefit of in-depth review of the DCAT Project, makes the following recommendations.

1. If the government review of transmission service rates is not concluded by mid 2014, or if it does not include a review of Tariff Supplement 6 (TS 6), the Commission should consider a review of TS 6 and invite all interested parties to participate in the review as this is a significant and urgent issue.

2. While the Panel finds that the DCAT Project TS 6 calculation should not include the estimated costs of the Phase 2 GDAT project, the forthcoming industrial rate review should consider how deposits and contributions should be assessed when a project is phased. Furthermore, the issues of additional deposits/contributions by DCAT customers should be examined by a future Panel when the Phase 2 GDAT CPCN application is heard.

1.0 INTRODUCTION

This Decision considers an application by British Columbia Hydro and Power Authority (BC Hydro, the Applicant) for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Dawson Creek/Chetwynd Area Transmission (DCAT) Project (Application, Project). The Project is proposed by BC Hydro to address electricity supply constraints in the Dawson Creek and Groundbirch areas in the Peace region of northeast British Columbia. In particular, reinforcement of the transmission system is required to enhance the reliability of service to existing customers and to meet increasing new industrial customer load. The extraordinary industrial load growth is primarily attributable to the development of the unconventional gas reserves (shale gas) in the Montney gas basin located in this area.

1.1 The Applicant

BC Hydro is mandated through legislation to generate, transmit, distribute and sell electricity; upgrade its power, transmission and distribution systems; and purchase power from, or sell power to, a firm or person. BC Hydro states that it has both the financial and technical capacity to undertake the Project. The BC Minister of Finance is BC Hydro's fiscal agent as the Government of British Columbia is BC Hydro's shareholder. The Project team is composed of full time BC Hydro employees and external consultants who have extensive experience in project delivery for transmission facilities. Key consultants include SNC-Lavalin Inc. for engineering design services and AMEC Americas Limited (AMEC) Earth and Environmental Limited for field surveys and development of environmental overview assessment reports.

1.2 The Project

The Project consists of three main components; namely, the construction of the new Sundance Lakes Substation (SLS), the construction of a double circuit 230 kilovolt (kV) transmission line for 60 km from SLS to Bear Mountain Terminal Substation (BMT) and for 12 km from BMT to the Dawson Creek Substation (DAW), on a new or expanded right-of-way (ROW), and the expansion of BMT. The existing transmission infrastructure serving the areas consists of a 138 kV system.
BC Hydro states that in the absence of an upgrade it will be unable to meet existing load and the

forecasted industrial load growth in the area while complying with appropriate Mandatory Reliability Standards (MRS).

Three land acquisitions are proposed to implement the Project. The proposed new SLS substation involves the acquisition of 8.5 hectares (ha) for the new site. The expansion of the BMT terminal includes the acquisition of approximately 14 ha of land. Finally, a new 33 metre ROW is required for the transmission line route, except where portions of the route parallel existing lines. For these portions, the required additional width of ROW may be less.

The Project also entails decommissioning and dismantling the existing 138 kV transmission line between the DAW substation and BMT as well as approximately 90 percent of the existing 60 kilometers (km) long 138 kV line between SLS and BMT.

BC Hydro expects the Project to cost $222 million, while the authorized P90 cost estimate is $257 million. The planned and expected in-service date is April 30, 2014.

1.3 Stakeholders and Interveners

The primary stakeholders are both the existing or native load customers and the new industrial load customers. The base case Other Load, forecast at 96 megawatts (MW) for F2013 or in the 77 to 103 MW range, includes existing residential, commercial and industrial demand, except for unconventional gas producer demand. The base case load for unconventional gas producers is forecast at 54 MW with a high case of 60 MW and a low case of 32 MW for F2013.

In support of the Application, the five industrial customers that are seeking more that 10 MW of power have been asked to provide security for their pro rata share of the costs of the Project. They are also in discussions with BC Hydro regarding commercial arrangements for pre-ordering of equipment. These customers are:

- Air Liquide Canada;
- Arc Resources Ltd. (ARC);

- Encana Corporation (Encana);
- Murphy Oil Company Ltd. (Murphy); and
- Shell Canada Ltd. (Shell).

These companies requested, and were granted, a late Intervener status to address the importance and sense of urgency of the Project. Other Late Interveners include the Ministry of Energy and Mines (MEM) and the City of Dawson Creek. In addition, earlier registered Interveners include:

- The Canadian Association of Petroleum Producers (CAPP), the Clean Energy Association of B.C. (CEA) and Current Solutions Incorporated (CSI), further representing industry interests;
- The Association of Major Power Customers (AMPC), B.C. Old Age Pensioners' Organization et al (BCOAPO), subsequently renamed as British Columbia Pensioners' and Seniors' Organization (BCPSO) and the Commercial Energy Consumers Association of British Columbia (CEC) representing the base load customer groups; and
- B.C. Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA), the Canadian Office and Professional Employees Union Local 378 (COPE) and Mr. Vern Ruskin.

WMFN is another stakeholder and an Intervener, with a primary focus on adequacy of consultation with First Nations. Neighbouring property owners also embody a stakeholder group. Landowner interests are represented by Mill Valley and Indian Creek Land Owners Group as well as by Interveners Gary and Marilyn Robinson (the Robinsons).

1.4 Proposed Tariff Revision and Rates

Two of the five new industrial customers have opted for distribution service, rather than transmission service, under the applicable Large General Service (150 kW and over) Rate Schedules 1600, 1601, 1610, or 1611 of the Electric Tariff. Large General Service (LGS) customers are billed according to the LGS two-part Conservation Rate. The other three new industrial customers will receive transmission service under the Transmission Service – Stepped Rate, Rate Schedule 1823 of the Electric Tariff, which was also conceived as a conservation rate.

The Terms and Conditions (T&C) for transmission service are contained in Tariff Supplement 5 (Electricity Supply Agreements) and TS 6. TS 6 spells out the T&C for a new transmission customer to receive service. If transmission system reinforcement is required in order to provide the service, it provides for a contribution and/or a deposit from a customer, depending upon the relative cost of the extension project and the benefits that BC Hydro expects to receive from the new customer taking service.

Similar provisions exist under the Electric Tariff T&C, section 8, Distribution Extensions for distribution customers but they relate only to distribution extension costs – not transmission reinforcement costs. Currently TS 6 is not applicable to distribution customers. Consequently, security for the transmission reinforcement costs is required from the three transmission customers but not from the two distribution customers. To address this inequity, BC Hydro is applying to revise the Electric Tariff T&C section 8.3 to allow TS 6 to apply to distribution customers seeking new service in excess of 10 MW that require system reinforcements in order for it to be able to recover security from the two distribution customers as well.

1.5 Orders Sought

Pursuant to sections 45, 46, 58 and 61 of the *Utilities Commission Act* (*UCA*) BC Hydro has applied to the British Columbia Utilities Commission (BCUC, Commission) seeking an order that:

- Grants a Certificate of Public Convenience and Necessity to construct and operate the Dawson Creek/Chetwynd Area Transmission Project as set out in the Application;
- Directs BC Hydro to file with the Commission semi-annual updates on the actual Project schedule and costs with a comparison to the plan, including any variance as compared to the P90 Cost Estimate;
- Directs BC Hydro to file a final report within six months of the end or substantial completion of the Project which is to include the Project costs as compared to the P90 cost estimate and to provide an explanation of any material variances;
- Approves a revision to the Electric Tariff which adds a paragraph to follow the third paragraph in section 8.3 of the Terms and Conditions, providing as follows:

In addition to any Extension Fee and revenue guarantee to be paid or provided by a Customer pursuant to this part, for new services that:

(a) have a total expected maximum Demand greater than 10,000 kW; and

(b) partially or wholly make necessary System Reinforcement (as defined in TS 6) to the transmission system in order to provide service to the distribution system to which the Customer is or will be connected;

the Customer will be subject to the terms and conditions of TS 6 in respect of the System Reinforcement in accordance with TS 6.

1.6 Regulatory Process

The review of the Application was conducted primarily by way of a written proceeding. The review of adequacy of First Nations' consultation, however, was conducted in an Oral Hearing Phase held from July 9 to July 10, 2012.

At the request of BC Hydro the Commission Panel temporarily suspended the review process on November 30, 2011. (Exhibit A-23) BC Hydro was concerned that the Commission and Interveners in their Information Requests (IRs) were focused on "policy and factual areas that were not addressed in the DCAT Application, were largely outside the scope of what BC Hydro had anticipated would arise and ...could have ramifications far beyond the DCAT project." Therefore, BC Hydro required "time to collaborate with Government and potentially key stakeholders before setting out policy positions on such fundamental issues." (Exhibit B-19)

By letter dated March 23, 2012, BC Hydro requested that the Application review be reactivated. (Exhibit B-22) The Commission lifted the temporary suspension on April 11, 2012. (Exhibit A-26)

The regulatory process is summarized in further detail in Appendix B.

1.7 Key Issues Arising

While the DCAT Project may appear to be a relatively routine CPCN application for a new transmission line, it has managed to raise some controversy. The causes of controversy may be identified as follows:

(i) the need for transmission reinforcement results from a dramatic and perhaps unprecedented growth in one relatively confined area of the province, largely driven by a single industry that is not present elsewhere in the province;

(ii) the DCAT Project is being proposed at a time of major developments in the area both in the natural gas industry and in connection with other BC Hydro projects, such as Site C.

Specifically, the Application has raised numerous policy and regulatory issues including:

- Uncertainty related to the load forecast of the unconventional natural gas sector;
- Concerns over the risk of stranded assets and/or underutilized system after 20 years;
- BC Hydro’s obligation to serve competitively priced and reliable power;
- Implications and relevance of the “N-1 service standard”;
- Operation of the Electric Tariff with respect to customer contribution in the case of system reinforcement, including the role of the security deposit;
- Allocation of energy and capital costs between old and new customers on the system;
- The appropriateness of using the Industrial Electric Tariff as a mechanism to subsidize the development of private industry;
- Consideration of the DCAT Project in relation to province-wide system planning and BC’s energy objectives;
- Greenhouse gas (GHG) emission and GHG emissions reductions implications of the DCAT Project;
- Adequacy of First Nations’ consultation, including cumulative impact; and
- The anticipated Phase 2 transmission project required for the area, described as Greater Dawson Creek Area Transmission.

Some of these issues have been ruled out of scope, as indicated in Section 2.0. The remaining issues are addressed in more detail in Sections 7.0, 8.0 and 9.0.

2.0 REGULATORY AND POLICY FRAMEWORK

Applications for CPCNs arebregulated by the *UCA* and informed by the CPCN Guidelines, as issued by the Commission. Generally, a CPCN application hearing will consider the need for the project, project alternatives, and the impact of the project on various stakeholders. This section outlines the specific legislative, regulatory and policy provisions that apply to this CPCN Application.

2.1 *Utilities Commission Act*

This Application for a CPCN has been made by BC Hydro pursuant to the section 46(1) of the *UCA*. The CPCN procedure is governed, specifically, by sections 45 and 46 of the *UCA*, as attached in Appendix A.

Specifically, the Commission must determine whether the CPCN is necessary for the public convenience and properly conserves the public interest. (*UCA*, s. 45(8)) If the Commission determines that a CPCN application is in the public interest, then it may impose conditions about the duration and termination of a project or the construction, equipment, maintenance, rates or service relating to the project, all within the mandate that it is in the public interest. (*UCA*, s. 45(9))

Furthermore, the Commission may grant a CPCN, refuse to grant a CPCN or limit the construction or operation of the project, for the partial exercise of a right or privilege, and may attach terms and conditions about the duration of the right or privilege:

> 46(3) Subject to subsections (3.1) to (3.3), the commission may issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.
>
> (3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by
>
> > (a) British Columbia's energy objectives,

> (b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and
>
> (c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

This section sets out two distinct areas that are particularly interesting in the context of this Application: that the Commission Panel must consider the interests of persons in BC that receive or may receive service from BC Hydro, and that the Panel must consider an applicable integrated resource plan approved under section 4 of the *Clean Energy Act* (*CEA)*. In this context, there are two important considerations. First, the Province of BC has provided evidence that they will be conducting a separate hearing process to deal with industrial rates for BC Hydro. In fact, the MEM stated:

> "In light of evolving provincial economic development, energy and environmental priorities, including the new direction for provincial energy policy announced on February 3, 2012 and available at http://www.gov.bc.ca/ener/natural_gas_strategy.html, the Government plans to undertake a broader review of industrial electricity policy, including retail access." (Exhibit C16-2, p. 2)

Second, although subsection 46(3.3)(b) states that BCUC must consider "an applicable integrated resource plan approved under section 4 of the *Clean Energy Act",* the Applicant has not yet filed its Integrated Resource Plan (IRP) for approval by the government. Thus there is no approved IRP to consider as the 2008 Long Term Acquisition Plan is not an approved IRP. However, absence of an approved IRP does not discharge the Commission of the responsibility to consider long term resource planning issues. It simply limits the evidence before the Panel. The Commission must still apply its judgment about what to consider relevant and should look to other sources of information. In this proceeding BC Hydro has provided the System Planning Report as well as information from its draft IRP which may be relevant evidence.

Accordingly, when deciding whether to issue a CPCN to BC Hydro under section 46(3.3) the Commission must consider BC's energy objectives, any applicable IRP approved under section 4 of the *CEA*, and the requirements of section 19 of the *CEA*. The *CEA* will be considered further below.

In addition, the Commission must be satisfied that a utility's service to the public is adequate, safe, efficient, just and reasonable.

2.2 Certificates of Public Convenience and Necessity Application Guidelines

In 2010, the BCUC issued CPCN Guidelines (Order G-50-10). The CPCN Guidelines were issued to support utilities' CPCN applications, and were not intended to alter the fundamental regulatory framework. The CPCN Guidelines provide direction for filing evidence for issues, such as: the need for the project, project justification, project description, project alternatives, and project budget, as well as guidance on the consultation of impacted stakeholders.

2.3 First Nations Information Filing Guidelines for Crown Utilities

In recognition of the Commission's obligation to determine if a Crown corporation has met its constitutional duty to consult First Nation bands, the Commission requires that Crown utilities, in CPCN applications, file certain information with their application. (Order G-51-10)

The Information Filing Requirements provided with the Guidelines include First Nations identification, assessment of the scope of the duty to consult, a summary of consultation process to date, and a conclusion which provides the Crown utilities' overall view as to the reasonableness of the consultation process.

In determining the duty to consult, the Commission Panel must consider whether a duty to consult exists, the seriousness of the potential adverse impacts, whether the Crown utility's consultation has been adequate, and whether the Crown utility has adequately accommodated the First Nation, if necessary.

2.4 *Clean Energy Act*

The Province of British Columbia (the Government) has legislated its energy objectives for the province generally, and for BC Hydro, specifically. BC's energy objectives are contained in the *CEA* and referred to in the *UCA*. Pursuant to section 1 of the *UCA*, "British Columbia's energy objectives" have the same meaning as in section 1(1) of the *CEA*, which refers to the objectives set out in section 2 of the *CEA*.

2.4.1 British Columbia's Energy Objectives

The relevant objectives listed in section 2 of the *CEA* for the purposes of the Application include:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;

(c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions;

   (i) by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007,

   (ii) by 2016 and for each subsequent calendar year to at least 18 percent less than the level of those emissions in 2007,

   (iii) by 2020 and for each subsequent calendar year to at least 33 percent less than the level of those emissions in 2007,

   (iv) by 2050 and for each subsequent calendar year to at least 80 percent less than the level of those emissions in 2007, and

   (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to encourage economic development and the creation and retention of jobs; and

(k) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia.

2.4.2 Other Relevant CEA Sections and Special Direction No. 10

The Commission is also bound by section 6 and section 19 of the *CEA*, Special Direction (SD) No. 10 and the Electricity Self-Sufficiency Regulation. The Province of British Columbia provides SDs to the Commission, from time to time, to clarify government objectives.

Section 6 of the *CEA* provides a goal for the province respecting Electricity Self-Sufficiency. SD No. 10 approved and ordered on June 25, 2007 by OIC 508 defined "critical water conditions" as meaning the most adverse sequence of stream flows occurring within the historical record.

Section 19 of *CEA* specifically applies to BC Hydro, and provides that BC Hydro must pursue actions to meet BC's energy objectives and must use prescribed guidelines in planning for the construction and extension of facilities and for the purchase of energy.

Further, the Government amended SD No. 10 and the Electricity Self-Sufficiency Regulation by Orders in Council Nos. 35 and 36. Changes to SD No. 10 deletes the definition of "critical water conditions" and provides, in its place, "average water conditions", which impacts the Applicant's commitment to becoming electrically self–sufficient. For the purposes of this Application, the impact of SD No. 10 is that it allows BC Hydro to plan to meet provincial load with the use of BC Hydro's Heritage Assets, when water is average, and not critical. This effectively means that a larger portion of BC Hydro's load requirements will be met from its Heritage Assets. BC Hydro's Heritage Assets have a lower cost associated with them as a source of electricity. Accordingly, this impacts the average cost of energy in the province. SD No. 10 will be considered further in Section 3.6 and 5.3.7.

The Commission Panel is required to consider how the Applicant plans to meet the requirements of the *CEA* in CPCN applications.

2.5 Special Direction No. 9

On February 2, 2011, the Government amended SD No. 9, to provide the following:

> "2.1 (1) In deciding whether to issue to a public utility other than the authority a certificate in respect of an electricity transmission project under section 46(3) of the Act, the commission must consider, in addition to the matters referred to in section 46 (3.1) of the Act, the government's objective of encouraging public utilities to develop adequate electricity transmission infrastructure in the time required to serve persons who receive or may receive service from the public utility.
>
> (2) In deciding whether to issue to the authority a certificate in respect of an electricity transmission project under section 46 (3) of the Act, the commission must consider and be guided by, in addition to the matters referred to in section 46 (3.3) of the Act, the government's objectives referred to in subsection (1) of this section."

In this Decision, the Commission Panel will consider, among other things, the Government's objective of encouraging the Applicant, BC Hydro, to develop adequate electricity transmission infrastructure to customers in a timely fashion.

2.6 Mandatory Reliability Standards and the N-1 Service Standard

Section 125.2 of the *UCA* provides that the Commission must adopt MRS made by an appropriate standard making body, if the Commission finds that such standards are in the public interest and are required to maintain consistency in BC with other jurisdictions with MRS. Consequently, and pursuant to section 125.2 of the *UCA*, BCUC has adopted the Western Electric Coordinating Council (WECC) standards for reliability, which includes the N-1 operating criterion for service on the bulk transmission system. N-1 means that the transmission system will remain operative even with the loss of one key physical element.

Specifically, on June 4, 2009, WECC Mandatory Reliability Standard TPL-002-0a was adopted by Order G-162-11, and requires that the system remain stable with thermal and voltage limits within acceptable ratings, with no loss of demand or curtailment of firm transfers, and no cascading outages, when an event on the transmission system results in the loss of a single element. Further, Requirement R6 of MRS TOP–002-2a (also adopted by Order G-162-11) provides the following:

> Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements.

These requirements apply to the "bulk power system" which is defined to mean:

> "(a) electrical generation facilities and transmission facilities, including interconnections with neighbouring systems, that are generally operated at voltages of 100 kilovolts or greater, and
>
> (b) transmission facilities that are generally operated at voltages of less than 100 kilovolts and that are, on their own or in combination with other generation, transmission or distribution facilities, material to reliability but excludes radial transmission facilities, regardless of voltage, serving only end-users of electricity with one transmission service."
>
> (Mandatory Reliability Standards Regulation, BC Reg. *32/2009* pursuant to *UCA)*

As part of the review of this CPCN Application, the Commission Panel must also consider this N-1 planning criterion and whether the Applicant has provided evidence of a plan to comply.

2.7 Tariff Matters

2.7.1 Electric Tariff

BC Hydro's Electric Tariff was approved by the Commission on May 31, 2008. It contains Definitions, T&Cs and Rates for Service at the Distribution Voltage and Rates for Service at the Transmission Voltage. T&Cs for Transmission service are contained in Tariff Supplements 5 and 6.

In particular section 8 of the T&C in the Electric Tariff relating to 'Distribution Extension - 35 kV or Less' is of relevance to this Application as BC Hydro is applying for a revision to section 8.3 to permit it to recover security for the cost of transmission reinforcements from certain distribution customers. Section 8.3 currently stipulates that the Customer Extension Fee for Rate Zone 1, which includes the DCAT project area, is the estimated construction cost of the extension less BC Hydro's contribution toward the extension. It also states that for new services with a total expected maximum demand greater than 500 kilovolt amps (kV.A), the estimated construction cost of the extension shall include system improvement costs. Section 8.4 is also of particular relevance to the Application as it states that "customers with an expected maximum demand, as reasonably forecast by BC Hydro, greater than 100kW may be required to provide a guarantee in the form of cash or an equivalent form of guarantee acceptable to BC Hydro."

2.7.2 Tariff Supplement No. 6

TS 6, Agreement for New Transmission Service Customers, became effective January 21, 1991, pursuant to Order G-4-91. It was the result of a negotiated settlement between BC Hydro and its Industrial Customers, and has not been modified since that date. TS 6 spells out the T&C for a new transmission customer to receive service. If transmission system reinforcement is required in order to provide the service, it provides for a contribution and/or a deposit from a customer, depending upon the relative cost of the extension project and the benefits that BC Hydro expects to receive from the new customer taking service. In particular Appendix 1 to TS 6 is relevant to this Application.

TS 6 also spells out the terms under which a new customer can earn back their deposit, including a provision for a refund of a contribution or a deposit in the event that additional new load is added within seven years of the in-service date of the extension project.

In its Reasons for Decision to Order G-4-91, the Commission reiterated BC Hydro's submission that the Basic Transmission Extension is the responsibility of BC Hydro, who shall undertake the required work at the Customer's expense.

The Commission also stated that it was given the assurance that the agreed T&C of the Electricity Supply Agreement and Facilities Agreement would have no financial impact on any other rate classes: "The agreement of the parties, coupled with the lack of inter-class financial impact has been most persuasive in convincing the Commission to accept the negotiated documents." (Reasons for Decision, Order G-4-91)

2.7.3 Utility System Extension Test Guidelines

The Commission issued voluntary Utility System Extension Test Guidelines (Extension Guidelines) in 1996, by Order G-80-96. These Extension Guidelines were the result of an oral generic hearing, initiated by the Commission after receiving applications from several utilities on issues related to system extensions. Six utilities participated in the hearing: BC Hydro, West Kootenay Power Ltd., BC Gas Utility Ltd., Centra Gas British Columbia Inc., Princeton Light and Power Company, Limited, and Pacific Northern Gas Ltd. The purpose of the hearing was to look broadly at the utilities' system extension policies and to make them more consistent with each other.

The Commission had previously issued Order G-19-96 in the matter of Utility System Extension Tests on February 16, 1996. On March 18, 1996, BC Hydro filed a Notice of Application for Leave to Appeal the decision on the grounds that the Commission had exceeded its jurisdiction with respect to certain orders or directions in the Decision. A Notice of Application for Leave to Appeal was also filed by Methanex Corporation, Council of Forest Industries and the Mining Association of British Columbia (the Industrials) regarding the Commission's directions in the System Extension Decision with respect to the incorporation of social costs into system extension tests.

Subsequently, the Commission received applications for a reconsideration of its System Extension Decision on behalf of BC Hydro and the Industrials. As a result of the reconsideration, Order G-80-96 made the System Extension Guidelines voluntary.

In the reconsideration hearing, BC Hydro acknowledged that the Commission does have the jurisdiction to review and analyze the extension test included in a filed tariff, in particular the charge, as part of its rate making authority, although the policy considerations which go into the test are exclusively BC Hydro's. (T1: 68, 69)

2.8 Consultation

The CPCN Guidelines provide that relevant applications must consider the public interest. To become aware of public interest issues, an applicant must provide a consultation process that is relevant to the project, as outlined in the CPCN Guidelines. At a minimum, this consultation process is expected to provide sufficient notice, both in terms of time and transparency, of the proposed project and project alternatives. In addition, the CPCN Guidelines anticipate that notice is not enough. Some engagement to discuss the issues, if any, is required. Further, an applicant is expected to provide evidence that this process has taken place, including a communications log, a list of identified issues, if any, and a summary of outcomes from the process, such as reasons why an issue has not been dealt with, how issues have been mitigated, and how a stakeholder with an issue has been accommodated.

2.9 Other Scope Considerations

In addition to the regulatory and policy framework that confines the focus for determinations in this Decision, the Commission Panel is also guided by its own conclusions in the second Procedural Conference in this matter, which took place on May 2, 2012. At the conference, the issue of the scope of the Application was considered. BC Hydro’s request to reactivate the Application (Exhibit B-22) contained five topics that BC Hydro suggests are out of scope, re-categorized by the Panel into four issues as follows (Exhibit A-28):

1. **RATES:** whether rolled in rate principles should apply on the BC Hydro system; whether distinctions should be made between old and new customers for ratemaking; and, whether postage stamp rates, which have been in effect since BC Hydro was created in 1962, remain appropriate on its system;

2. **OBLIGATION TO SERVE:** whether distinctions should be made between old and new customers respecting whether to serve and service level;

3. **N-1 SERVICE STANDARD:** whether its N-1 service standard, required pursuant to the MRS standards that were developed pursuant to BCUC Orders G-67-09, G-167-10, G-162-11, and G-175-11 remains the appropriate service standard; and

4. **BC ENERGY OBJECTIVES:** whether consideration of the DCAT Project requires the BCUC to consider province-wide system planning issues and BC's Energy Objectives under the *Clean Energy Act.*

The Panel heard from each of the participants at the second procedural conference. The Panel made the following determinations respecting scope of this hearing:

1. Issues that relate to the appropriateness of rolled in rate principles, or postage stamp rate principles, as a system wide BC Hydro policy are out of scope. However, issues respecting the application of TS 6 to the DCAT Project so as to allow the Commission Panel to determine whether the DCAT Project is in the public interest, are in scope.

2. The Panel recognized BC Hydro's obligation to serve all customers who come to it ready, willing and able to meet the requirements that this Commission has said are necessary for customers to meet. However, the Panel wished to emphasize that the absolute obligation to serve is always in context: the service must meet the appropriate standards; options must be weighed diligently; and the service must be adequate, safe, efficient, fair and reasonable. Accordingly, these issues are in scope for this hearing.

3. The Panel acknowledged the Integrated Resource Plan process that has been established by the *CEA*. Province wide resource planning issues are out of scope. However, specific plans and planning methodologies, including increased load issues that relate to the DCAT area are within scope. Questions that relate to the appropriateness of the N-1 MRS standard are out of scope for this hearing, but questions about the application of the N-1 standard to this proposed project are well within the scope of this hearing. Particularly, BC Hydro's compliance with N-1 service criterion, in both the planning standard for the DCAT project and the operating standard, once the project is in service, are within scope. This may include issues respecting any further phases that support DCAT's compliance with the N-1 service criterion.

4. Questions that require BC Hydro to provide evidence of establishing priorities amongst the government of British Columbia policy objectives contained within section 2 of the *CEA*, as it relates to projects other than that contemplated in the DCAT CPCN are out of scope for this hearing. Any questions relating to the application of the *CEA* to the DCAT project is appropriate and necessary for a CPCN application.

In essence, the Commission Panel has limited the scope of the review to those issues that are directly connected to the proposed DCAT Project, and has determined that broader issues related to resource planning and rate impacts for the entire province are out of scope.

3.0 PROJECT NEED AND JUSTIFICATION

BC Hydro states that as a result of electrical load forecast in the Dawson Creek and Groundbirch areas, coupled with the existing transmission system constraints, an urgent upgrade to the high voltage transmission system supplying the region is required by the fall of 2013 in order to return the bulk transmission system to an acceptable level of service. BC Hydro further asserts the present system cannot currently serve the entire existing peak load with a single transmission element taken out of service (this single contingency is referred to as N-1) and is forecasted be unable to support the peak load with all transmission elements in service (referred to as N-0) by the winter of 2013/14. In the interim period prior to system inforcement, BC Hydro states, it continues to implement customer load shedding schemes to manage system load. (Exhibit B-1, pp. 2-1, 2-20)

This section describes the existing transmission system, its present constraints, the anticipated load growth in the area and the transmission constraints arising from such anticipated growth.

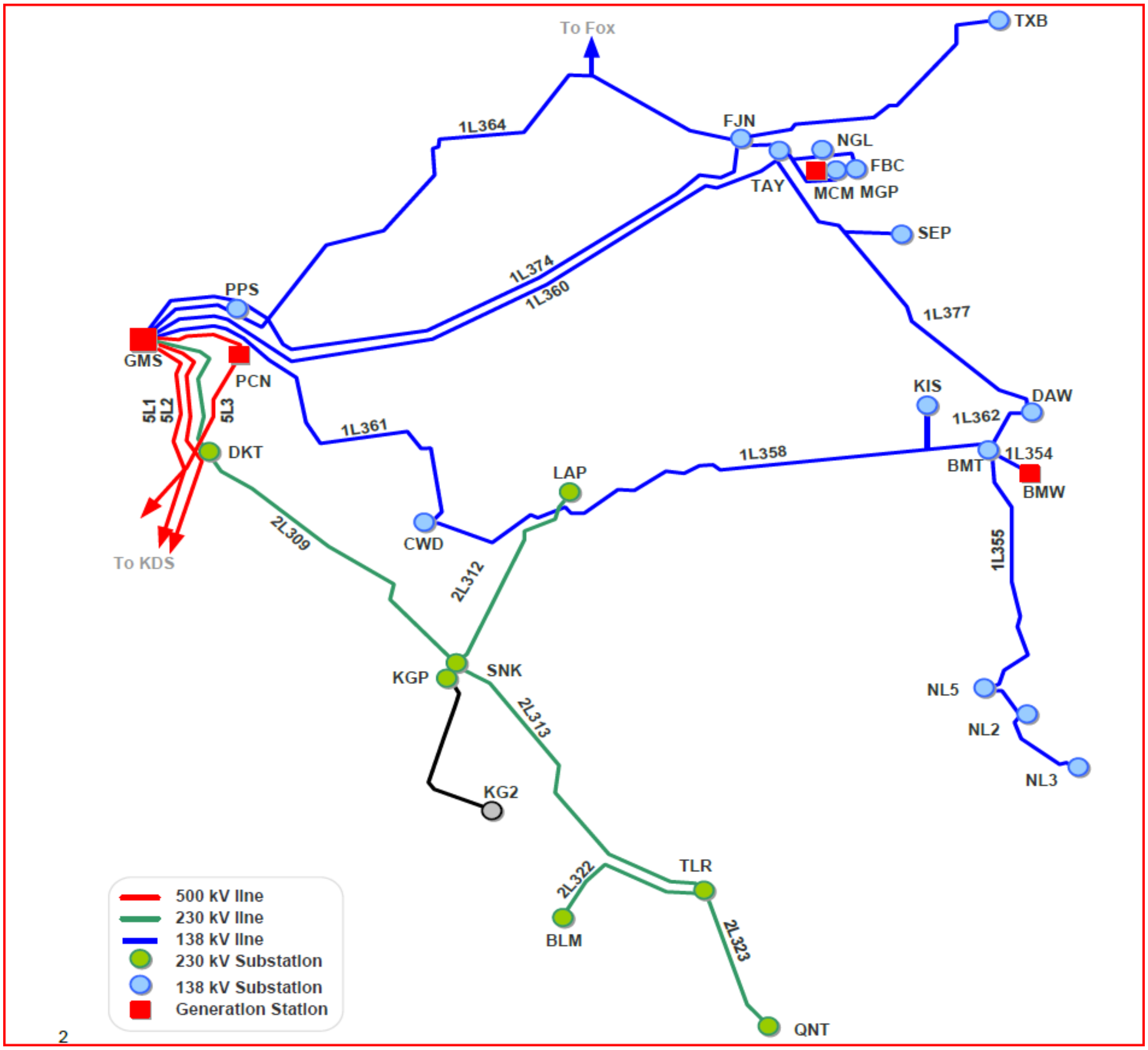
3.1 Overview of Existing System

3.1.1 Peace Region Transmission System

BC Hydro describes the Peace region of BC as a wide plain that lies east of the Rocky Mountains and is bisected by the Peace River, which flows from the Rockies in BC to Lake Athabasca in northeast Alberta. The major communities in the Peace region include Chetwynd, Fort St. John, and Dawson Creek which receive service from the138 kV transmission system, which has grown from its beginnings in the late 1960s to the early 1980's, interconnecting the substations of Chetwynd (CWD), DAW and Fort St. John (FJN). (Exhibit B-1, pp. 2-1 to 2.2)

A geographic one-line diagram of the interconnected transmission system in the Peace region is shown below.

Figure 3-1 Existing Peace Region Transmission System

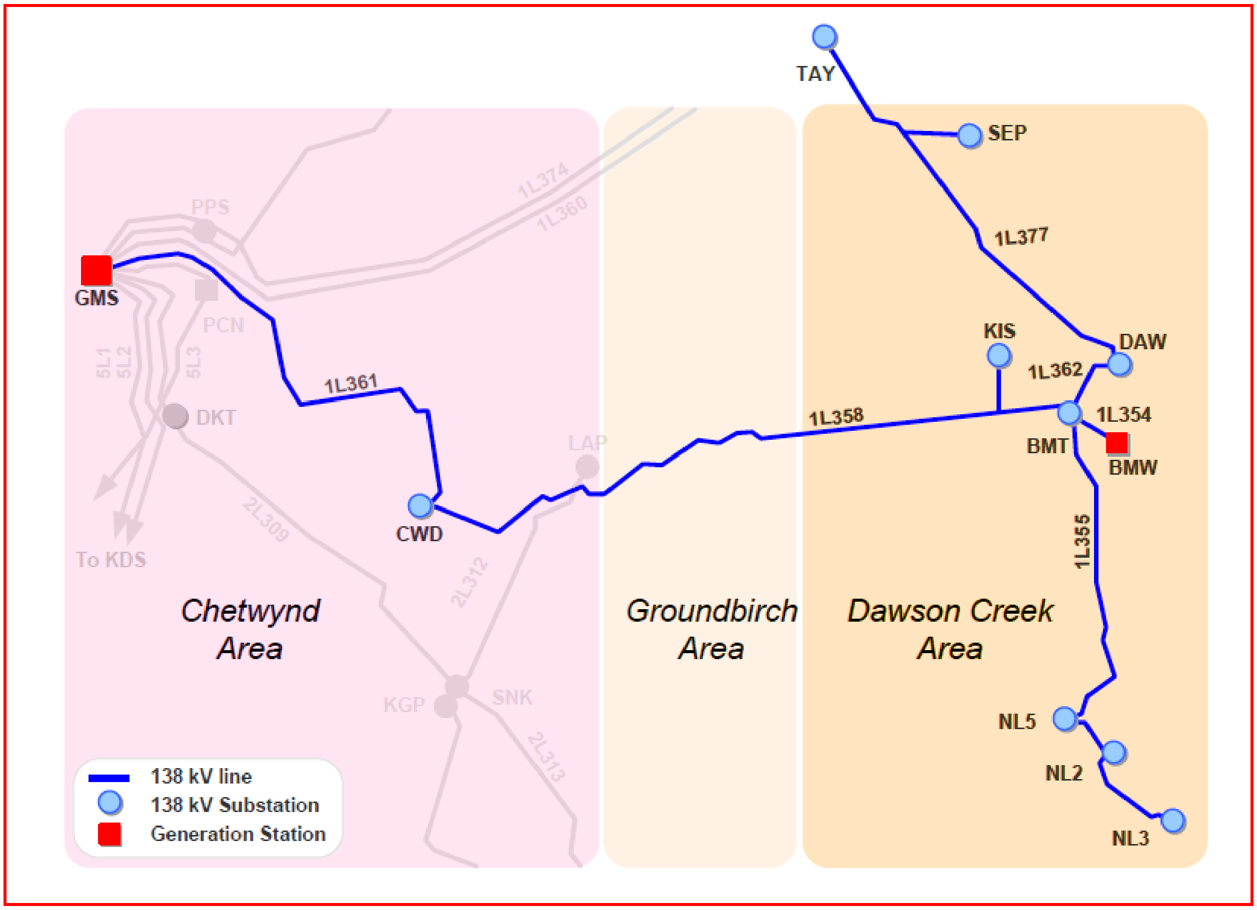


Source: Exhibit B-1, p. 2-3

3.1.2 The Dawson Creek Transmission System

BC Hydro seeks authorization to construct facilities required to upgrade part of the existing Peace region Transmission System, namely the Dawson Creek Transmission System shown in Figure 3-2 below. The current Dawson Creek 138 kV Transmission System serves the areas of Dawson Creek, Chetwynd and Groundbirch.

Figure 3-2 Dawson Creek Transmission System



Source: Exhibit B-1, p. 2-4

The Groundbirch area is expected to experience significant natural gas development and resulting electricity demand during the 30-year planning period. The need for the Project is driven by the load growth resulting from the natural gas developments in the area. (Exhibit B-1, pp. 2-4 to 2-6) That load growth is discussed more fully in the following section.

3.2 Dawson Creek Area Load Forecast

3.2.1 Introduction

This section identifies the load forecast volume. The load forecast in the Dawson Creek and Groundbirch areas (DC Area Load Forecast), comprises the following:

(a) Gas Producer Forecast which is the load for unconventional gas producers, and

(b) Other Loads Forecast which is all other loads including residential, commercial and industrial loads. This will also be referred to as Other Forecast.

BC Hydro has prepared a 20-year regional forecast for the Peace region (Exhibit A2-1, Appendix 3.2 Gas Producers – Northeast Gas) as part of its system wide Electric Annual 2010 Load Forecast. The DC Area Load Forecast which was created separately to provide a 30-year electrical demand forecast for the DCAT Project is consistent with the Electric Annual Load Forecast. 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.

BC Hydro describes the anticipated electric load in the Dawson Creek area as primarily the load in the City of Dawson Creek plus three new transmission voltage customers in the surrounding area. The City of Dawson Creek is an administrative and services centre with major economic activities in the surrounding area including agriculture, energy, and forestry. The Groundbirch area currently has no BC Hydro or customer owned substations. A distribution feeder from DAW currently serves a relatively small load in the Groundbirch area (less than 3 MW) but this area is expected to see significant natural gas development and resulting electricity demand during the 30-year planning period. (Exhibit B-1, pp. 2-5, 2-6) BC Hydro did not provide a load forecast for the Chetwynd area.

3.2.2 Forecast Results and Time Profile

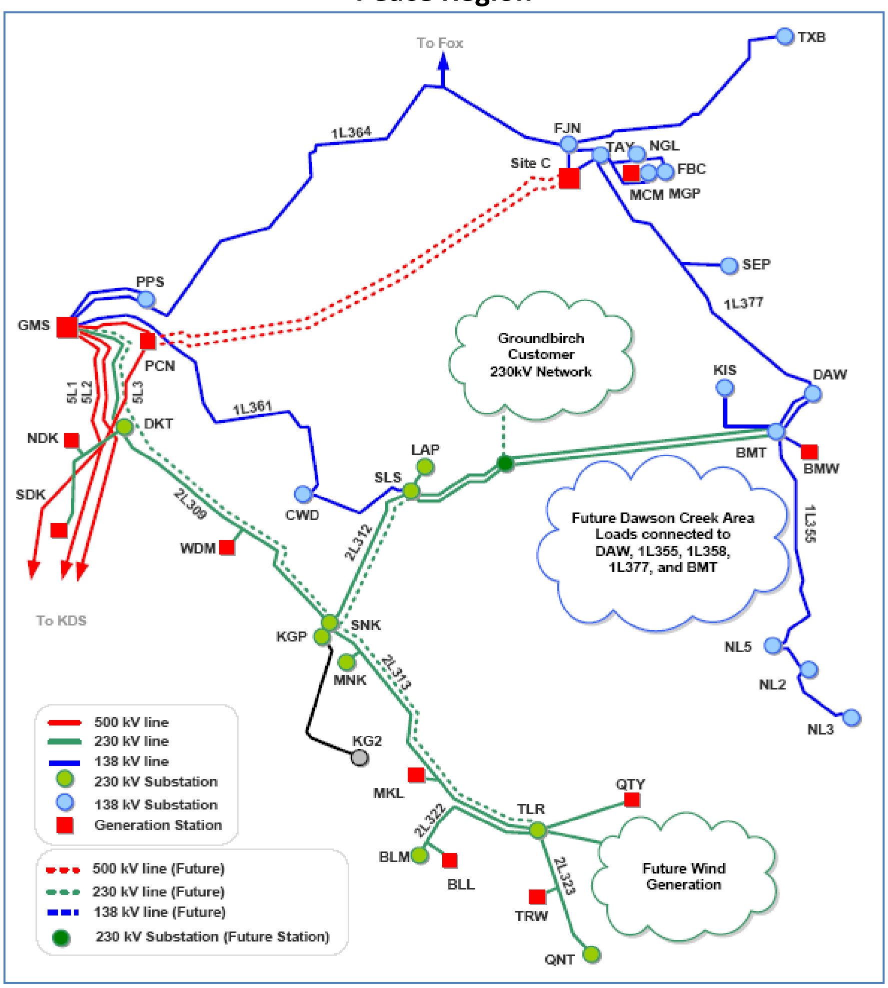
BC Hydro provided its Forecast Update as a part of the Supplemental Evidence. The Forecast Update considered the updated system wide Electric Annual 2011 Load Forecast, information from an extra year of current performance and related activity for each customer, developments in the near term spot market and in the long term markets, as well as general information available from consultants and the natural gas industry. (Exhibit B-22, Attachment 2, p. 22)

The Total Forecast (Gas Producer Forecast and Other Forecast) is summarized and shown in Appendix C. As indicated in Appendix C, the difference between the two consecutive years' forecasts – 2010 and 2011 - is significant. In aggregate, the DC Area Load is expected to reach a peak load of 425 MW between F2029 and F2031. BC Hydro did not consider demand side management (DSM) for the purposes of this CPCN Application because DSM savings are not expected to defer the in-service date for a project to increase transmission capacity, nor make a difference in developing the alternatives to meet the 30 year load forecast. (Exhibit B-1, p. 2-10)

3.2.3 Gas Producer Forecast

Montney Basin is a region with significant unconventional natural gas reserves, contained in shale formations, which require new, more aggressive techniques (e.g., hydraulic fracturing) to extract the gas. The Montney Basin spans both Alberta and BC Peace regions with both Dawson Creek and Groundbirch located in the BC portion of the area as shown below. (Exhibit B-1, Appendix B, pp. 75-76)

Figure 3-3 Possible Future Transmission System Configurations in the Peace Region



Source: Exhibit B-5, BCUC 1.18.3

The Gas Producer Forecast in the Application shows that the electrical demand will peak in F2027 at 278 MW rapidly increasing from 41 MW in F2011, and will decline to 103 MW in F2041 or to 37 percent of the peak. BC Hydro takes the position that its projection lies within the reasonable range of forecasts with respect to the rate of decline of gas production. According to the System Planning Report used in the Application, at the peak of electricity requirement in F2027, around 77 percent of the load in the DC Area Load Forecast is forecast to come from electricity requirements from large, single point loads that serve the shale gas sector. (Exhibit B-1, Appendix B, Figure 3, p. 79)

The flattening and eventual decline in the load forecast for the 30-year forecast of the Gas Producer Load is a reflection of the finite nature of the gas resources and the eventual forecasted decline of gas production. The timing and duration of demand is an issue of concern in the review of Gas Producer Forecast. (Exhibit B-5-1, BCUC 1.29.1)

BC Hydro expects the demand for electricity to rise dramatically in the near term F2011-F2015. (Exhibit B-1, p. 2-9) In the long term, the demand projections reflect gas producers who have indicated their intent to take service from BC Hydro or who have indicated interest but have not yet made any formal commitments.

In the Forecast Update, BC Hydro’s base forecast peak of gas producers’ electricity requirements will reach a plateau of 319 MW in the period F2022 to F2031. Gas producers make up approximately 75 percent of total load; the Other Loads are between 103 MW and 106 MW for the same period. (Exhibit B-22, Attachment 2, pp. 24, 31) The Forecast Update also shows that peak demand will continue for a longer period of time than described in the System Planning Report. The bases for this change are higher initial production rates, longer well life, and therefore improved overall production economics. (Exhibit B-22, Attachment 2, pp. 26, 28)

The Forecast Update shows that the actual measured peak load for the winter of F2012 was approximately 40 MW less than previously forecast, and the forecast for F2014 was reduced to reflect the influence of very low current natural gas prices as these prices have led to reduced drilling activity and production rates in the sector as a whole. Table 3.1 presents the Gas Producer

Load for the initial five years of the planning period for the DCAT Project including the load request from five new customers that account for the majority of the load.

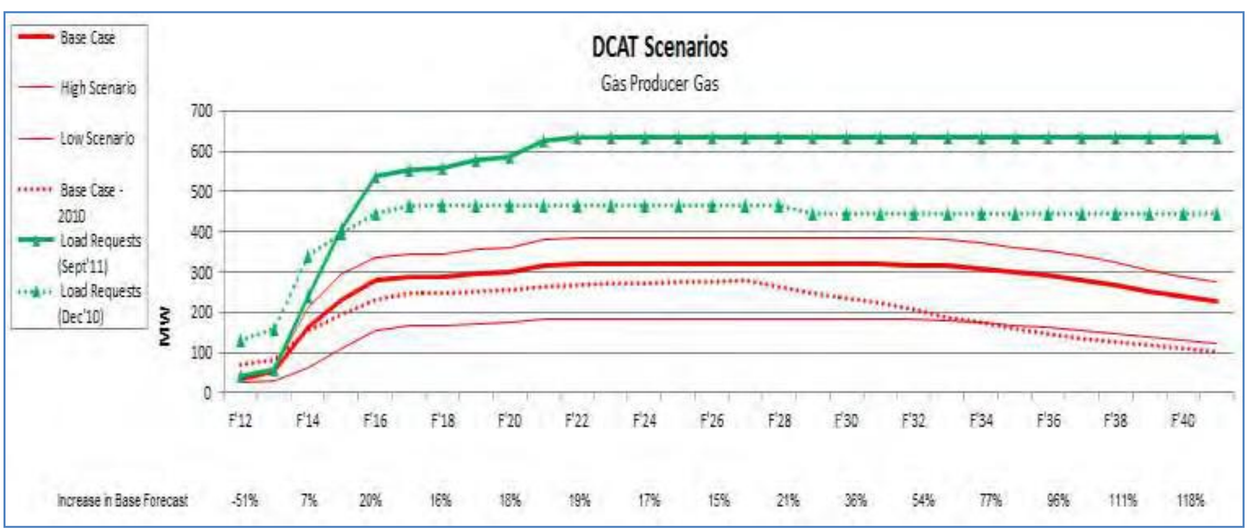
Table 3.1 Producer Load Forecast

MW	Forecast Update	Forecast from System Planning Report	Commitments From Five New Customers
F11	--	41	--
F12	34	70	27.6
F13	54	83	101.5
F14	164	153	138.5
F15	232	195	178.5

Source: Exhibit B-5, BCUC 1.28.1; Exhibit B-22, Attachment 2, p. 5, p. 24

Figure 3-4 below presents a comparison of the Gas Producer Load Forecast Base Case - 2010 and the Base Case – 2011 as well as the High and Low scenarios. As the figure shows, the updated Gas Producer Load is lower in F2012 and F2013 but rises more steeply and reaches a plateau at 319 MW; moreover the updated Gas Producer Load is not projected to experience overall decline until F2033, much later than F2027 in the original forecast.

Figure 3-4 DCAT Scenarios for Gas Producer Load



Source: Exhibit B-22, Attachment 2, p. 23

3.2.4 Other Loads Forecast

BC Hydro stated the Other Loads Forecast includes residential, commercial and industrial demand, for all customers, excluding unconventional gas producers, and consists of both distribution and transmission connected customers. This forecast is based on the historical analysis of current customer loads and key economic drivers. The Other Loads Forecast is developed using an econometric model that uses historical trends in peak demand and the relationship between peak demand and economic drivers such as housing starts, employment and Gross Domestic Product (GDP) for the entire region, and projections of these parameters. (Exhibit B-5, BCUC 1.34.3)

The following Table 3.2 presents the Other Loads Forecast for the initial five years of the planning period for the DCAT project.

Table 3.2 Other Loads Forecast

MW	Forecast Update	Forecast from System Planning Report
F11	-	60
F12	80	65
F13	96	70
F14	96	71
F15	97	73

Source: Exhibit B-22, Attachment 2, p. 31

While the early years' load in the planning period of the Gas Producer Forecast has been decreased in the Update, Table 3.2 shows that the Other Loads Base Case forecast in the Forecast Update has increased because BC Hydro has anticipated increased activity in the region over the entire forecast horizon. BC Hydro attributed the increase to activities directly associated with gas production such as gas processing, drilling, and well operations, with associated spin-off in all customer sectors. (Exhibit B-22, p. 29)

The Forecast Update revised the Other Loads electrical requirement in the long term to 98 MW in F2017 to 107 MW in F2041. This can be compared to the original Other Loads Forecast of 74 MW in F2017 to 87 MW in F2041. (Exhibit B-5, BCUC 1.28.1; Exhibit B-22, Attachment 2, p. 31)

3.2.5 High and Low Scenarios

BC Hydro also developed High Scenarios and Low Scenarios for both the Gas Producer Load Forecast and the Other Loads Forecast.

The main drivers for the Gas Producer High Scenario and Gas Producer Low Scenario are expectations for well production, economics and basin characteristics. (Exhibit B-1, Appendix B, p. 84) For the High Scenario relative to the base case, it was assumed more production would be realized through development of deeper zones and broader development areas and that the loads associated with customer load requests were given a higher probability of being realized; for the Low Scenario, the converse was true. (Exhibit B-5, BCUC 1.36.3)

The Other Loads High Scenario was generated via a top-down regional simulation that considers uncertainty in the key economic drivers. The Other Loads Low Scenario was simply developed by calculating the ratio between the Other Loads High Scenario and the Other Loads Base Case. (Exhibit B-1, Appendix B, p. 80)

3.3 Reliability of Load Forecast

As Interveners have expressed serious concerns over the reliability of BC Hydro's forecast, this matter is addressed here further in the context of the Project's economic feasibility. The reliability of the forecast is especially critical in relation to the urgency of the project, selection of the preferred alternative and the relative burden of risk for the existing vis-a-vis new customers.

3.3.1 Load Forecasting Issues and Risks

The Application highlights the unique nature of demand in the Montney Basin, the nature of gas producers' activity and their related interest in taking electricity. BC Hydro has taken the view that this CPCN proceeding ought not to be used to investigate issues that are better considered in the IRP process or other province-wide proceedings. The issues that have arisen include the terms and conditions of tariff supplements, industrial tariffs and rate structures as applied to gas producers, and postage stamp rate principle. All these issues relate to load forecasting directly and indirectly because they affect decisions by gas producers to configure their facilities to take electricity instead of relying on natural gas powered compression. In Order G-56-12, the Commission Panel determined that while province-wide resource planning issues are out-of-scope, specific plans and planning methodologies, including increased load issues that relate to the Dawson Creek area are within scope.

Accordingly, this Decision will not consider the broader issues of forecasting methodology which will be reviewed under the IRP process overseen by the MEM, but instead will examine the methodology to develop the region-specific and sector-specific forecast and any load forecast risks stemming from the use of such a methodology.

The review process has identified five forecasting issues from the DC Area Load Forecast methodology:

1. The Gas Producer Load Forecast is driven primarily by expected gas production. (Exhibit B-1, Appendix B, p. 81; Exhibit B-22, Attachment 2, pp. 26-28) The risk of unrealised gas producers load forecast may come from a decrease in market natural gas prices and tightening credit. This risk is evident in the Forecast Update for F2012 and F2013.

2. The ability of gas producers to make choices, notwithstanding inquiries to BC Hydro and expressions of interest in taking electrical services, to choose natural gas as an alternative energy source. The alternatives for gas producer customers include self generation and the use of gas driven compression and direct gas drives; however, BC Hydro has assumed an electrical percentage of 95 percent. (Exhibit B-5, BCUC 1.41.1; Exhibit B-14, BCUC 2.30.2)

3. The assumption of a ramp up in gas sector related electrical load is prefaced on the successful upgrade of the transmission system in the region. (Exhibit B-5, BCUC 1.41.2.1)

However, the application for upgrade or reinforcement of transmission capacity is dependent on the significant ramp-up (95 percent) assumed by BC Hydro.

4. Although gas producers are considered industrial customers by BC Hydro and take service at either the transmission rate or the industrial distribution customer rate, they are not typical industrial customers whose long-term forecast can be projected as a sector by an econometric model based on projections of economic activities. The decisions of gas producers on whether to develop in the Montney Basin, if at all, or whether to cease development after making commitment in the form of posting security, represent aggregate binary decision-making in nature, resulting in yes or no as opposed to incremental or cyclical load demand.

5. The Other Load Forecast no longer seems to be the "native load" but has included activities directly associated with gas production. (Exhibit B-22, Attachment 2, p. 29) As a result, even the Other Load will rise and fall with the fortunes of shale gas production in the Montney Basin region.

3.3.2 Forecast Methodology

The Gas Producer Load Forecast has been generated by BC Hydro using a bottom-up approach and also includes an iterative exercise with the top-down forecast.

The bottom-up forecast is based on customer-specific information and analysis and serves as BC Hydro's official load forecast. The top-down forecast is a macro forecast that is used to guide and confirm the bottom-up forecast. The bottom-up forecast originates from a compilation of current and expected customer load requests. In arriving at an 'expected' or most likely net customer service requirement, each customer request is evaluated, shaped and discounted based on information from various sources internal and external to BC Hydro. External factors come from a number of areas such as industry, producer publications and the top-down forecast. The top-down forecast is derived by creating and then multiplying three data sets: production x intensity x service percent.

The basis of the Montney Load Forecast, used by BC Hydro for the Gas Producer Load Forecast, is an unconventional gas production forecast for the entire Montney play. Gas production forecasts consider a number of third-party sources and are assembled by BC Hydro. Specific geographic information is also used to allocate the forecast into the five areas. This includes: customer requests for electricity, producer land holdings and production plans, the relative richness of the gas play by region, initial production results, current drilling activity and the proximity of the expected gas production to BC Hydro transmission infrastructure (Exhibit B-5, BCUC 1.30.1).

BC Hydro was asked whether the discussions that took place in the bottom-up forecast included: (a) the time profile of the area's load and consequent stranded asset as the demand is expected to decline to reflect the finite nature of gas resources; and (b) whether alternative non-electric, cost-effective fuel to produce natural gas was discussed. (Exhibit B-5, BCUC 1.29.1.1, 1.29.1.2)

BC Hydro states that a successful upgrade of the transmission system in the region would lead to a ramp up in gas producers seeking electrical service. (Exhibit B-5, BCUC 1.36.2) BC Hydro updated the time profile in the Forecast Update in the Supplementary Evidence and noted that it considered factors such as the distance between the producing region and electrical infrastructure when developing the percentage of electrical service that it would expect to supply to the oil and gas sector. While all the five areas in the BC part of Montney Basin (Dawson Creek, Groundbirch, Chetwynd, Fox/Fort St. John and G.M. Shrum) share an identical gas production forecast and intensity factor, BC Hydro projects that for Dawson Creek, electrical service from BC Hydro will go from 40 percent ramping up to 95 percent intensity factor over the forecast horizon and Groundbirch will go from 15 percent ramping up to 95 percent over the same period. Some of the energy required would be self-supplied by industry, e.g., customer direct gas compression and customer gas-fired generation. (Exhibit A2-1, Appendix 3.2, p. 99)

The updated Gas Producer Load Forecast, in terms of demand , as measured in megawatts, and the duration of demand over the planning period, results in more rapid growth in gas producer demands post-F2014 as well as anticipated peak demand from producers continuing over a longer period.

The Other Loads Forecast is based on historical analysis of current customer loads, and key economic drivers such as projected trends in regional housing starts, employment and the economy as measured by GDP. The updated Other Loads are expected to exceed the original forecast by 15 to 20 MW annually throughout the planning period. BC Hydro attributed the increase to activities directly associated with gas production.

Regarding the Gas Producer Load Forecast, BC Hydro states that the forecast of primary use for electricity in the production of natural gas includes policy reasons. It provided an example that encourages the substitution of natural gas drive compression with electric drive compression supplied by low carbon power from BC Hydro's electric system, which offers the potential to significantly reduce the increase in GHG emissions expected as a result of increased activity. (Exhibit B-1, p. 2-9)

In its DC Area Load Forecast, BC Hydro also discussed potential load by showing: (a) producers who have shown an interest; and (b) producers indicating intent. (Exhibit B-14, BCUC 2.15.1) As a result BC Hydro is studying a Phase 2 project for further reinforcements beyond the DCAT Project in order to provide N-1 service. BC Hydro stated that the updated DCAT load forecast does not advance the timing of a Phase 2 GDAT application. (Exhibit B-30, BCUC 4.4.1)

3.3.3 Managing Load Forecasting Risk

BC Hydro manages the load forecast risk by projecting high and low scenarios to address the likely range. It accepts that 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 but believes it can be managed by making appropriate arrangements with customers. (Exhibit B-1, p. 2-15) BC Hydro has entered binding agreement with each of the five customers who make up the majority of the load requirements by which each customer will provide security for their portion of the DCAT Project.

As noted earlier, the five industrial customers Air Liquide Canada, Shell, ARC, Encana and Murphy registered as Interveners and spoke to their requirements. They have addressed, in large part, the load forecast of gas producers, at least in the near term of the 30-year DC Area Load Forecast (Exhibit B-22, Attachment 2). As indicated in Table 3.1, these customers account for a large proportion of the Gas Producer Load Forecast in the near term of the planning horizon.

BC Hydro took the position that gas producers will be treated in the same manner as other customers in the same rate class. (Exhibit B-5, BCUC 1.38.3) This implies that electrical service at tariff rates will remain competitive relative to self-supply of energy (natural gas for fuel) for gas compression.

3.3.4 Implications of Accepting DCAT Load Forecast

The updated DC Area Load Forecast provided by BC Hydro in the March 23, 2012 Supplemental Evidence (Exhibit B-22) included the following input factors:

The reduction in the near term:

- a number of gas customers' requests in the DCAT in 2011 were being deferred and or reduced from what they had requested in 2010;
- gas forecasting experts were generally lowering their gas production forecasts for the Montney in the near term;
- acknowledgements from some gas producers that their drilling and production plans for the Montney were being lowered.

The increase in the long-term:

- gas forecasting experts in 2011 were generally raising their gas production forecasts for the Montney in the long-term;
- BC Hydro's 2011 gas production forecast is in line with updated industry expert projections;
- for the last two years, there have been an increasing number of export-related developments and announcements that signal growing support for increased gas development in Northeast BC in general;
- pipeline projects serving the area continue to proceed; and
- in a recent report dated April 2, 2012, the Ministry of Energy and Mines reported that the Montney play remains one of the most active natural gas plays in North America.

(Exhibit B-30-1, CEC 4.12.3)

Commission Panel Discussion

The Commission Panel finds that certain input assumptions are not fully supportive of such significant change, both in magnitude and duration of demand, from the original forecast to the Forecast Update. The Panel notes that notwithstanding that the gas producers' initial choice to use electricity instead of natural gas for their production process remains unchanged, the differences within one year in generating the DC Area Load Forecast, based on a bottom-up forecasting approach, show that significant variations can occur in forecast results for this type of activity. The variations can be caused by market conditions such as the commodity price of natural gas. The perceived business prospects by large gas producers also influence business activity.

The Commission Panel considers that even without judging the merits of the underlying assumptions, given that a change in assumption within one year could create the significant changes in the DC Area Load Forecast, it is worth proceeding cautiously when evaluating the robustness of the load requirement. Even though this Decision does not visit industrial electricity policy, the Panel is mindful that the DC Area Load Forecast has been built on a foundation of issues deferred to a system-wide proceeding. These issues continue to revolve around a group of customers who are gas producers with their own distinctive load factor, intensity of load requirement, time profile and revenue impact. These features adduced through evidence inform the robustness of the area-specific and sector-specific load forecasts.

For the Other Loads Forecast, which BC Hydro has characterized as more representative of BC Hydro's overall system loads, the Commission Panel finds that in the Forecast Update BC Hydro has established a link to unconventional gas production activities in the Other Forecast by anticipating high economic activity in the region from gas producers, and therefore the forecast growth in the Other Loads has become inextricably tied to the Gas Producer Forecast.

The Commission Panel acknowledges BC Hydro's established key parameters that differentiate each of the Producers. They are: the recoverable per average well; the gas recovered; the number of wells drilled; and the gas price range. However, the Commission Panel notes that factors such as the 'what-ifs' to policy changes on definition of clean energy, changes in producers' business decisions to continue production in Montney, and the relative future energy cost of using electricity versus natural gas for compression were not considered in the High and Low Scenarios. Furthermore, factors such as gas production activities that have led to the updated Base Case for Other Load are not input assumptions for the Other Load High and Low Scenarios.

The Commission Panel accepts that BC Hydro has been reasonable in mitigating the load forecast risk or lack of robustness inherent in this sector-specific and region-specific forecast. However, it also notes how sensitive the load forecast is to changes in input assumptions. This sensitivity in turn results in the increased long term load lacking some certainty.

For instance, the Panel notes that a shift in government policy could potentially alter the choice of energy in the production of natural gas, similar to a policy shift in the definition of 'clean' energy to include natural gas in order to promote the development of a liquefied natural gas industry in B.C. Such a shift in policy could result in natural gas generation of electricity closer to the site, as the renewed choice of natural gas as source of energy for some gas producers.

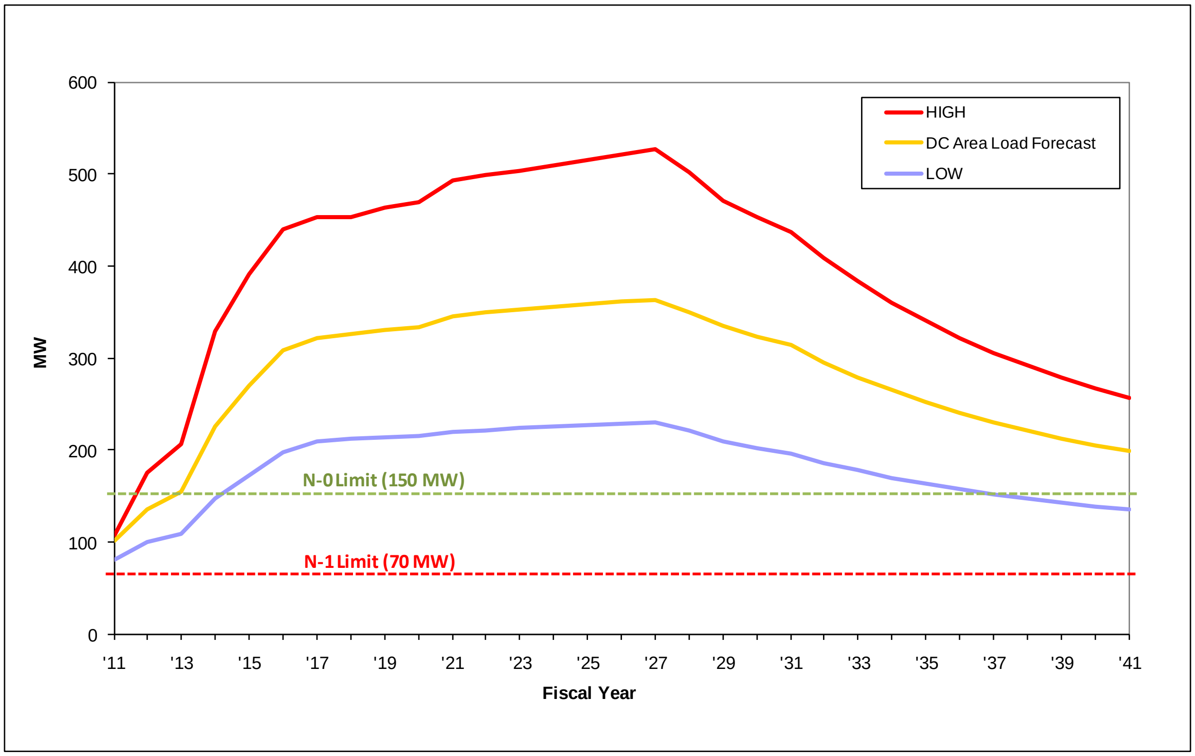
The Commission Panel concludes that while there is sufficient evidence to support the need for transmission reinforcement, the risks inherent in the forecast emphasize the need for the broad review of industrial tariff, rates and rate design, as discussed further in the Rate and Tariff section. Furthermore, this uncertainty supports BC Hydro's recommendation to proceed with Phase 1 only. The Phase 1 solution provides sufficient flexibility regardless of whether the actual load is above or below the forecast.

3.4 Existing Dawson Creek System Capacity Constraints

BC Hydro states that the current transmission system is capable of serving a Dawson Creek area load of 70 MW under N-1 conditions (a single transmission line taken out of service) and 150 MW under N-0 conditions (all transmission lines in service). This system cannot serve the predicted area winter peak load, of 114 MW (for fiscal 2012) increasing to 130 MW in fiscal 2013 under N-1 conditions, even without any increase in gas producer load. (Exhibit B-22, Attachment 2, pp. 24,

31) A graphic illustration of the existing system capacity constraints in relation to the load forecast is shown in Figure 3-5 below.

Figure 3-5



Source: Exhibit B-1, p. 2-14

The specific transmission lines serving the area (see Figure 3-2 above) that cannot be taken out of service during the winter peak loading (N-1) are:

- 1L377 Taylor to Dawson Creek (TAY-DAW);
- 1L361 Gordon M. Shrum to Chetwynd (GMS-CWD);
- 1L358 Chetwynd to Bear Mountain Terminal (CWD-BMT); or
- 1L362 Bear Mountain Terminal to Dawson Creek (BMT-DAW).

BC Hydro further asserts that starting in F2014 the system will not be able to support the winter peak load in the Groundbirch and Dawson Creek areas, even without any increase in Gas Producer Load, with all of the above transmission lines in service (referred to as N-0 Limit of 150 MW), as shown in Figure 3-5 above. BC Hydro submits that the loss of any one of these lines during winter peak loading results in low voltages below agreed upon levels, voltage instability, and/or voltage collapse or overloading of the remaining transmission supply line(s). (Exhibit B-1, pp. 2-11 to 2-14)

It is BC Hydro's expectations that even when the DCAT Project comes into service, some customers will not have N-1 level of service. (Exhibit B-22, Attachment 2, p. 73; Exhibit B-30, BCPSO 4.4.1) Only when the GDAT Project comes into service, will BC Hydro be able to meet the updated load forecast on an N-1 basis. BC Hydro further states that the 102 MW Bear Mountain Wind Farm, located approximately 15 km southwest from the City of Dawson Creek, cannot supply dependable generation to satisfy load requirements because such generation is considered an intermittent source due to the variable nature of wind. (Exhibit B-1, p. 2-13)

BC Hydro states the DCAT Project will increase the capacity from 70 MW to 185 MW under N-1 conditions and the N-0 capacity will increase to about 405 MW after the DCAT Project goes into service. (Exhibit B-14, BCUC 2.17.1) BC Hydro further states that all new industrial loads requested in the Dawson Creek area either have accepted or will accept load shedding under N-1 conditions, and that any new load over 1 MW will be required to enter into a load shedding agreement. (Exhibit B-22, Attachment 2, pp. 7, 8)

In summary, BC Hydro states that the current load conditions significantly exceed system limits at the required level of reliability for both near the term and long term anticipated growth and that adding new transmission load in the Dawson Creek/Groundbirch area is not possible until a major transmission project is added to the area. BC Hydro asserts that immediate action is required to address the above constraints. Exhibit B-1, pp. 2-1, 2-11)

3.5 Applicability and Significance of the N-1 Service Standard

At issue is whether there is an obligation for BC Hydro to provide service under N-1 conditions to all network connected loads in the Dawson Creek area, and how that obligation may apply to those loads intended to be served by the DCAT Project. Is the proposed DCAT Project adequate to meet the N-1 planning standards to which BC Hydro adheres, or must DCAT be considered along with

GDAT? In the latter case, there may be impacts on the project costs and the amount of security deposit or contribution that the new customers must provide and/or make.

BC Hydro discusses the requirements of MRS TPL-002-0 (System Performance Following Loss of a Single Bulk Electric System Element (Category B)) and TOP-002-2 (Normal Operations Planning), and states that "the BCUC has adopted the N-1 standard for service on the bulk transmission system, as that standard is defined by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC)". (Exhibit B-22, Letter dated March 23, 2012, p. 6 of 11)

BC Hydro further states that "where single element outages show impacts that do not meet the N-1 planning standard, BC Hydro is required by the standard to have written plans that show how the standard will be met in response to single element outage (N-1) events, including a schedule for implementation of those plans, and a discussion of the expected in-service dates of facilities with consideration of implementation lead times. In some situations, a capital project like the DCAT Project is required to comply with these requirements." (Exhibit B-22, Letter dated March 23, 2012, p. 7of 11) BC Hydro states that based on existing load forecasts and transmission system capacity constraints, some new customers would have to wait for further system reinforcements beyond the DCAT Project – i.e. GDAT - to be served under N-1 conditions. The GDAT Phase is not included in this Application but options for design of the approach are addressed in it.
(Exhibit B-22, Attachment 2, pp. 7-8)

BC Hydro submits that "...the DCAT Project alone will permit the five new customers to be served when the system is in an N-0 condition as opposed to the N-1 reliability level required in the long term." All are aware of this and have been informed of the requirement to sign Remedial Action Scheme (RAS) agreements. Further, all new industrial loads requested in the Dawson Creek area either have accepted or will accept load shedding under N-1 conditions and any new load over 1 MW will be required to enter into a load shedding agreement. (Exhibit B-22, Attachment 2, pp. 7-8)

BC Hydro further states it has advised all its bulk system customers that it expects service under N-1 conditions will be accomplished through the Phase 2 GDAT project but that this approach is dependent upon the Commission issuing a CPCN first for the DCAT Project and then for a GDAT project. If the Commission declines to issue a CPCN for one or both of these projects, BC Hydro indicates it "…will seek appropriate alternative ways to meet its obligation to serve these customers." However, it also indicates that in that circumstance, service would be considerably delayed. (Exhibit B-22, Attachment 2, p. 8)

The City of Dawson Creek concurs, stating that "[t]he N-1 reliability standard has been adopted by Commission Orders G-67-09, G-167-10, G-162-11 and G-175-11. It is the standard which Hydro is legally obliged to supply, and which the rest of the Province routinely expects." (City of Dawson Creek Final Submission, p. 2)

The CEC disagrees with this characterization, stating that "… apparently these customers are demanding at considerable expense for the last increments of reliability." It submits that the two-phased approach is BC Hydro's response to the rapidly emerging requirements and its limitations in bringing the planning along at the same time. (CEC Final Submission, p. 25) However, the CEC does not believe this should be a reason for denying the CPCN. The second phase GDAT project or some alternatives will be needed and it is sufficient to proceed with the DCAT CPCN in anticipation of solving the standard of service problems later. This is particularly true given the high level of reliability of the transmission lines and the customer willingness to proceed with load shedding schemes in place as part of their terms of service until other steps can be taken. (CEC Final Submission, p. 18)

Commission Determination

The Commission Panel observes that comingling the formal obligatory requirements contained in Mandatory Reliability Standards TPL-002-0 and TOP-002-2 with a concept termed the "N-1 planning standard", or similar variations, is not helpful to advancing the understanding of the requirements contained in the MRS. In particular, the Panel notes Commission Order G-167-10 adopts Standard TPL-002-0 which requires that the system remain stable with thermal and voltage limits within acceptable ratings, with no loss of demand or curtailment of firm transfers, and no cascading outages, when an event on the transmission system results in the loss of a single element. Footnote (b) to Table 1 of Standard TPL-002-0 allows for "controlled interruption" of "some local Network customers" in the event of single contingencies:

> "b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."

The Commission Panel also notes that Standard TPL-002-0a, which has superseded Standard TPL-002-0 by virtue of Order G-162-11, is consistent with the foregoing.

In the supplemental evidence, BC Hydro clearly stated that under MRS it is required to serve all its network-connected bulk customers to the N-1 standard and would accomplish that objective through the GDAT project. Until that time BC Hydro is remaining compliant by relying on the ability to implement controlled load shedding. The Commission Panel considers the continued use of such schemes an acceptable and compliant procedure until such time as system reinforcements or other circumstance no longer require their use, provided such schemes do not threaten the Bulk Electric System or cause a cascading outage to occur.

The Commission Panel agrees the GDAT project is necessary to provide N-1 service to the customers that have implemented post-contingency load shedding schemes, but disagrees that the GDAT project is required for compliance with MRS.

Should the fact that the DCAT Project provides for an increase in load, but does not meet the N-1 level of reliability, be grounds for denying the CPCN? The Panel agrees with the CEC and is persuaded that this is insufficient reason to deny the CPCN. However, the service provided to the five new industrial customers by the DCAT Project creates issues for this or future Panels to consider as discussed in Section 8.3.

Accordingly, the Panel determines that, with appropriate load shedding agreements, DCAT will provide the required reliability, regardless of whether the GDAT project is completed in a timely fashion. BC Hydro has stated its intention to proceed with GDAT, and has claimed a mandatory obligation to do so. The merits and need for the GDAT project are not before this Commission Panel to consider.

3.6 Load Resource Balances and Urgency

In this section, the Panel considers to what extent does the urgency of serving Dawson Creek area load contribute to the selection of DCAT Project as the preferred alternative - because of its earlier in-service date as compared to the other alternatives?

3.6.1 Load Resource Balance

The value of incremental energy can be a factor in both the comparison of alternatives and the assessment of rate impact, and because the value of incremental energy is dependent on the load resource balance, the load resource balance needs to be considered.

BC Hydro initially took the position that the cost of energy to serve incremental customer loads in the DCAT Project area is not relevant to the decision to approve the Application, because the energy cost to serve load is generally common to all alternatives, and should therefore not be included in the analysis. (Exhibit B-14, BCUC 2.25.2) Nevertheless, BC Hydro stated that it would value the incremental energy required to supply the forecasted load at $129/MWh. (Exhibit B-14, BCUC 2.25.1) This value is based on the 2009 Clean Power Call Report updated to 2011 constant dollars. (Exhibit B-1, p. 3-9, Appendix B, p. 31)

In Exhibit B-22, BC Hydro changed the value of the incremental energy from $129/MWh to the plant gate price of $116/MWh, apparently in recognition that a significant amount of the energy acquisitions in the Clean Power Call were from the Peace River region in proximity to the DCAT Project. (Exhibit B-22, Attachment 2, p. 36; Exhibit B-30-1, CEC 4.17.2)

Subsequent to the change in the definition of self-sufficiency from critical water to average water conditions brought into effect by the Electricity Self Sufficiency Regulation and SD No. 10, BC Hydro again revised the value of the incremental energy because BC Hydro is forecast to be in a surplus condition until at least F2017. (Exhibit B-22, Attachment 2, pp. 35, 36) As long as the system is in a surplus condition, BC Hydro forecasted the value of the incremental energy to be $50/MWh and after the surplus is exhausted, the value is then $116/MWh.

BC Hydro provided its assessment of both energy and capacity load resource balance for two cases: with and without the incremental load from the Douglas Channel Liquefied Natural Gas (LNG) facility and the Kitimat LNG facility (the "Initial LNG" loads). The energy balance is summarized in Table 3.3 below.

Table 3.3 Energy Surplus/Deficit

GWh	F2017	F2021	F2026	F2031
Surplus/(Deficit) with Initial LNG	(761)	(4,935)	(7,367)	(12.478)
Surplus/(Deficit) without Initial LNG	3,039	346	(2,087)	(7,197)

Source: Exhibit B-30-1, CEC 4.17.9, CEC 4.16.2

BC Hydro stated the system will still be in surplus until F2017 with the Kitimat LNG load. BC Hydro further noted that it does not anticipate incurring any incremental costs to acquire energy for the LNG customers until F2017 at the earliest, and not until F2022 without the Kitimat LNG load. (Exhibit B-30, BCUC 4.7.2)

The balance for the system peak capacity for the same two cases is summarized in Table 3.4.

Table 3.4 Capacity Surplus/Deficit

MW	F2017	F2021	F2026	F2031
Surplus/(Deficit) with Initial LNG	(936)	(1,167)	(1,697)	(2,436)
Surplus/(Deficit) without Initial LNG	(255)	(486)	(1,017)	(1,756)

Source: Exhibit B-30-1, CEC 4.17.9

As discussed in a later section, the load resource balance affects the selection of the preferred alternative through the value assigned to system losses, which is driven by the surplus condition of the energy load resource balance, and not the capacity deficit.

CEC submits that given the government's new LNG policy of allowing natural gas generation for the LNG facilities to be categorized as clean energy, the significant and long duration of surplus would appear to be closer to being a certainty. (CEC Final Submission, p. 11)

3.6.2 Urgency of the System Upgrade

As noted earlier, BC Hydro stated that it is necessary to upgrade the regional transmission system as soon as possible because the transmission 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. (Exhibit B-1, p. 2-1)

In its Forecast Update, BC Hydro states that updated load forecast suggested that load can be expected to ramp up a little more slowly over 2012 and 2013, but then rise to a higher and more sustained peak. (Exhibit B-22, Attachment 2, p. 35) Currently there is a queue forming for both distribution and transmission service requests and all new industrial loads greater than 1 MW requested in the Dawson Creek area either have accepted or will accept load shedding under N-1 conditions. Any new load over 1 MW will be required to enter into a load shedding agreement. (Exhibit B-22, Attachment 2, pp. 7, 8)

However, in the absence of a supply reinforcement, BC Hydro stated that natural gas production development is unlikely to be significantly affected by the ability of BC Hydro to provide electrical service to gas producers, because in the absence of sufficient electrical supply, gas producers have an option of self-supplying their energy needs by consuming natural gas. (Exhibit B-6, CEC 1.18.1)

Commission Determination

The Commission Panel finds that a project is required to resolve constraints in the existing 138kV Transmission System in the Dawson Creek area, to serve significant load growth, and to move toward reliable service. Accordingly, the need has been justified pending further findings in this Decision.

The Panel also finds that the need for the DCAT Project has a number of drivers, among them, the pace of load addition and the need to reliably serve the load consistent with MRS standards. With respect to the pace of load addition, the Commission Panel notes that the large increase in Gas Producer load will only occur if electricity is available. In the absence of sufficient electrical supply, the Gas Producers will likely self-supply energy and the pace of natural gas development in the region would not be affected, although the Other Load would still materialize.

The Commission Panel accepts BC Hydro's load forecast and notes it has been revised by BC Hydro using the best available known information. However, there are risks to the load forecast which may arise from future natural gas prices as highlighted in Section 3.3.

As previously discussed, with respect to the requirement to remain compliant with the MRS as a driver of the urgency of the DCAT Project, the Commission Panel notes BC Hydro's ability to implement remedial action schemes/load shedding strategies, in response to system contingencies in order to preserve service to the remaining connected loads, is a compliant response. Furthermore, the Panel notes that four of the five new industrial customers appear to have made temporary arrangements for at least a portion of their respective requirements to manage until the DCAT Project is built. Air Liquide Canada, which does not have that option, should be able to receive service from BC Hydro in the short term within the existing system.

Therefore, the Commission Panel is not persuaded that the DCAT Project, while needed, necessarily must be in service by April 30, 2014. Furthermore, the Commission Panel is not convinced that the need to provide N-1 service to all connected load by a certain date is in itself useful or determinative in selecting one alternative over another. This will be addressed further in Section 5.0.

4.0 PROJECT DESCRIPTION

This section discusses the major components of the proposed Project and reviews the transmission line route and station site selections.

4.1 Project Components and Infrastructure

BC Hydro states the Project is comprised of the following elements:

- a new 230/138 kV SLS having provision for eight 230 kV line bays, one 230/138 kV power transformer and two 138 kV line bays. Existing 230 kV line 2L312 from Sukunka Substation (SNK) to Tembec Substation (LAP) will be connected to SLS in an in/out arrangement. The existing 138 kV line 1L358 from CWD will terminate at SLS rather than BMT;
- an approximately 60 km in length 230 kV double circuit steel pole transmission line from the new SLS to BMT;
- an approximately 13 km in length, 230 kV double circuit steel pole transmission line from BMT to DAW operated at 138 kV and located on a new ROW;
- BMT will be converted from a 138 kV switching station to a 230/138 kV substation. In addition to the four 138 kV lines which connect to BMT, it will have two 230 kV line bays, two 230/138 kV power transformers and one more 138 kV line bay;
- DAW will be expanded to add one more 138 kV line bay and complete the 138 kV bus ring arrangement;
- the existing 138 kV transmission line 1L362, which runs between DAW and BMT, will be decommissioned and removed; and
- approximately 55 km of existing 138 kV transmission line 1L358 will be decommissioned and removed between SLS and the transmission tap off 1L358 to the customer owned Kiskatinaw Substation (KIS). This tap is located approximately 5 km west of BMT.

(Exhibit B-1, p. 4-1)

4.2 230 kV Transmission Lines

4.2.1. Proposed Structure and Conductors

BC Hydro provides that the structure selection for the new 230 kV transmission lines, which include the 230 kV lines from SLS to BMT (2L329 and 2L333) and the lines from BMT to DAW (1L362 and

1L350 (constructed to 230 kV standard and operated at 138 kV), considered the following parameters:

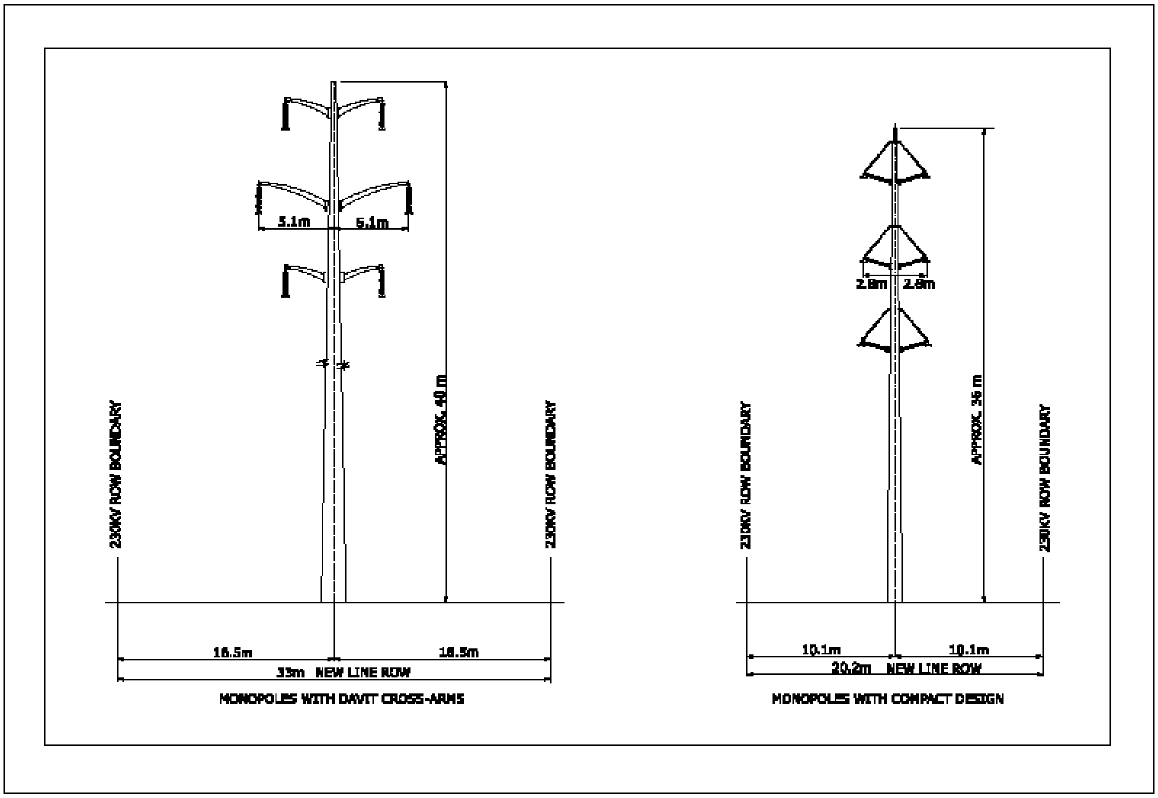
- potential impacts to land use, including agricultural operations, environment, other infrastructure, and potential archaeological areas, resulting from number of structures, footprint, structure support and right-of-way requirements;
- sharing of existing ROW with respect to existing lines 1L358 and 2L312;
- capital costs;
- construction considerations including access requirements and vegetation removal;
- maintenance considerations including vegetation; and
- aesthetic considerations.

(Exhibit B-1, p. 4-2)

Various structures, based on BC Hydro standards, specifications and designs, were considered for use in the Project. These included single circuit (H-frame, steel monopole, steel lattice tower) and double circuit (steel lattice tower, compact steel monopole, and steel monopole). (Exhibit B-1, p. 4-2)

Double circuit steel monopoles have been selected by BC Hydro as the typical structure for the Project for the following key reasons: significantly lower number of structures, two circuits on one set of structures, reduced ROW requirements, minimal guy wire support, smaller footprint resulting in less environmental and land use impacts and lower life cycle costs. Alternative tower designs will be used in some areas after special consideration. The required evaluation will be conducted in consultation with landowners while considering engineering, cost and maintenance. A typical 230 kV double circuit steel monopole structure with davit arms and a compact monopole structure respectively are shown in Figure 4-1 below. (Exhibit B-1, p. 4-3)

Figure 4-1 230 kV Steel Monopoles



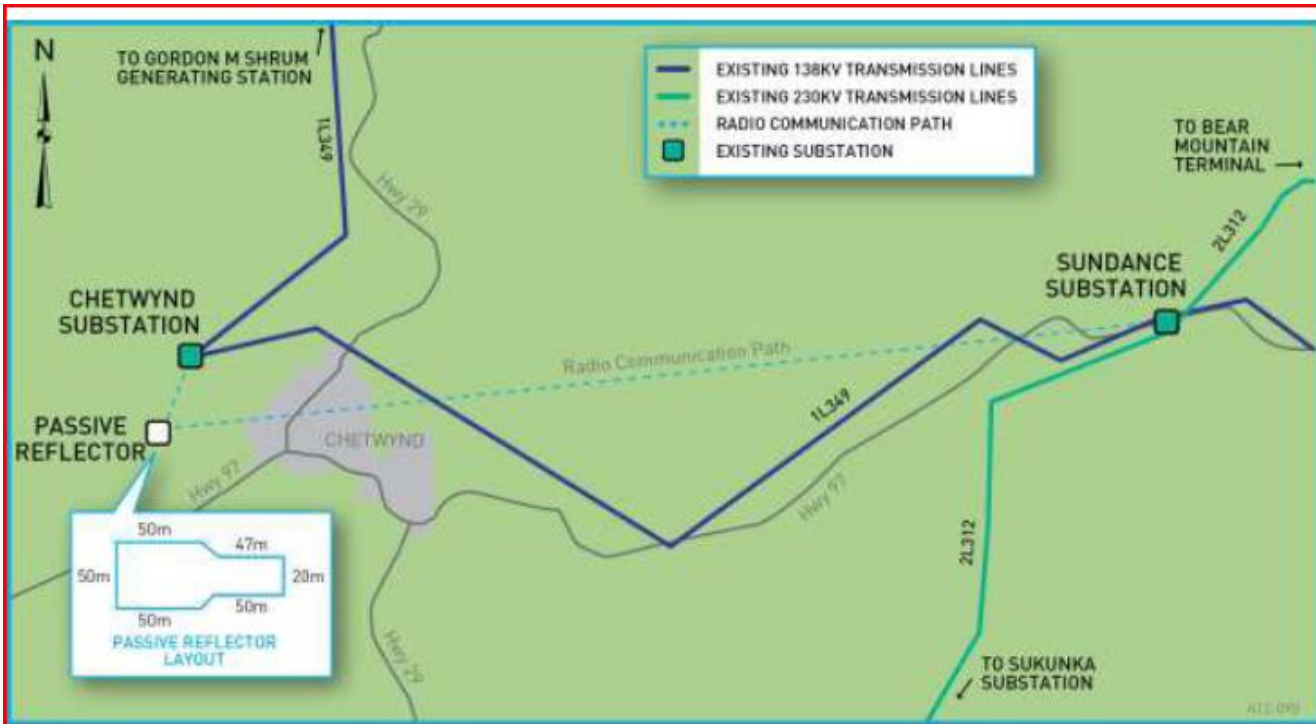
Source: Exhibit B-1, p. 4-4

The preferred conductor (duplex Drake) was selected to comply with BC Hydro and CSA standards. This selection considered a combination of factors such as conductor sag, audible noise, radio interference and conductor strength. (Exhibit B-1, p. 4-6)

BC Hydro indicates the proposed line will have overhead ground wires (about 9.1 mm in diameter) for the first three spans or 500 m (whichever is greater) from each substation to mitigate the effects of lightning strikes, as per BC Hydro practice. To provide effective shielding and minimize the height of the poles, it is proposed to attach the overhead ground wire to short davit arms extending from the pole centre. (Exhibit B-1, p. 4-4)

BC Hydro further explains that telecommunications between stations in the transmission system is required to protect and control the transmission system. To enable telecommunications between SLS, BMT and DAW, the proposed transmission line will include fiber optic cable hung on the poles under the primary conductors. (Exhibit B-1, p. 4-4) In addition to the fiber optic cable strung on the transmission structures, the communication network will require the construction of a passive microwave radio reflector about 2.5 km west of CWD substation as shown in Figure 4-2 below. The site is located on Crown land and is approximately 0.4 ha in size. A passive reflector consists of a support structure approximately 15 m in height, mounted with a billboard approximately 8 by 12 feet that will reflect microwave communication signals from the new SLS substation to the existing CWD substation. The layout of the reflector station will include space for a helipad. A total of approximately 50 m x 50 m of cleared area is required to accommodate the reflector and the helipad. (Exhibit B-1-3, p. 4-19; Exhibit B-22, Appendix A, p. 2 of 19)

Figure 4-2 Proposed Location of the Passive Reflector Site



Source: Exhibit B-1-3, p. 4-19-A

4.2.2 Right-of-Way Requirements

Typical ROW requirements for each of the structure types to be used in construction of the 230 kV lines are shown in Figure 4-1 above. BC Hydro notes 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. The existing 230 kV ROW (for line 2L312) is about 35 m wide. Where the new line is located parallel to 2L312, the required ROW widening will be approximately 22 m. (Exhibit B-1, p. 4-5)

4.2.3 Clearing Requirements

BC Hydro states 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 or 320 acres. One time clearing of additional danger trees outside of the ROW may also be required for the initial line construction and to ensure safe operation of the line. (Exhibit B-1, p. 4-5, Appendix F, p. 21)

4.2.4 Access Requirements

BC Hydro states ground access is required for clearing, construction and maintenance of the transmission line. This includes access to structure locations, marshalling areas and installation set-up sites. After completion of construction, access will be required for maintenance activities only. (Exhibit B-1, p. 4-6)

BC Hydro further notes there are major forest service roads, public and private roads and access trails along the route. Its preference is to use existing access to the extent feasible. If required, small extensions from existing roads and trails will be built during the construction of the transmission line. BC Hydro plans to maintain natural barriers, where possible, to limit continuous access on the ROW and does not plan to construct any bridges over any major creeks or waterways along the ROW. It will also develop a construction environmental management plan (EMP) that addresses environmental concerns with respect to access requirements and construction within the ROW. (Exhibit B-1, p. 4-6)

4.3 Transmission Lines Route Selection

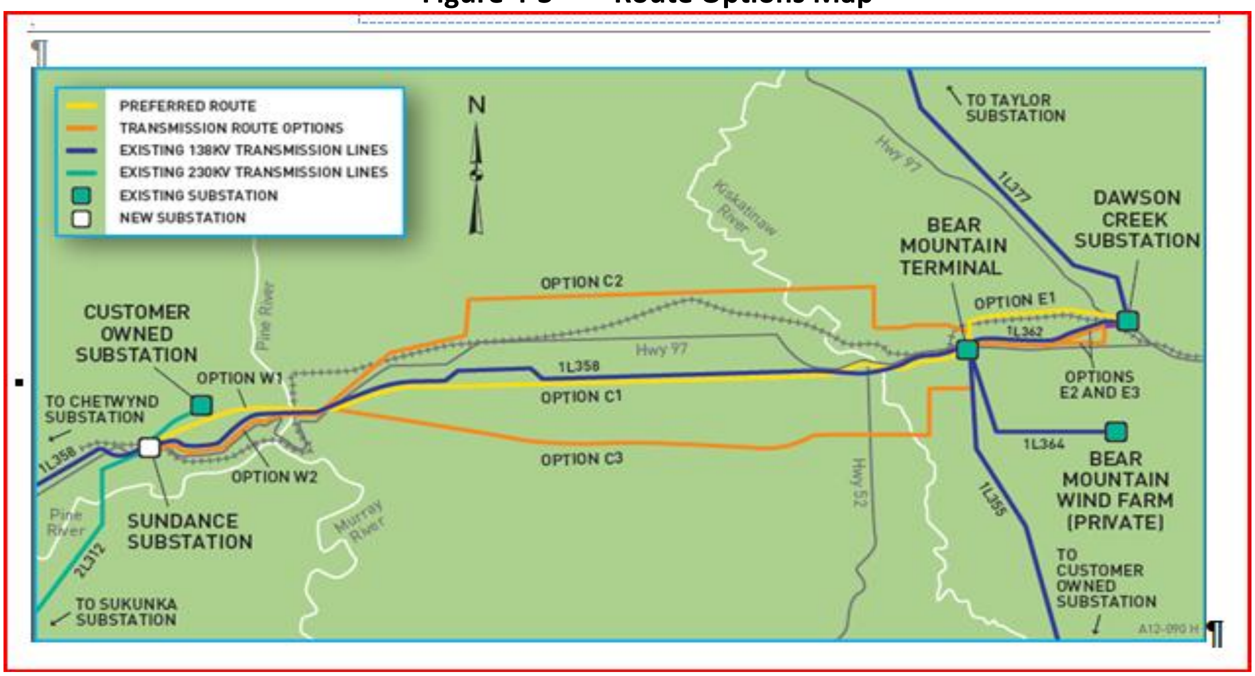
4.3.1 Route Selection Process

BC Hydro states that to facilitate evaluation of route options, the route from BMT to the new SLS substation was divided into three segments:

- East Segment - DAW to BMT;
- Central Segment - BMT to east of the Pine River; and
- West Segment - East of the Pine River to SLS.

BC Hydro explains that route options were developed for the proposed new line within each segment and route options were evaluated also within each segment. An overview of the route options and the preferred overall route is shown in the Figure 4-3 below. (Exhibit B-1, pp. 4-7 to 4-13)

Figure 4-3 Route Options Map



Source: Exhibit B-1, p. 4-7

BC Hydro states the route evaluation is based on a number of objectives, which include minimizing potential impacts to the environment and 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. (Exhibit B-1, p.4-7 to 4-8)

BC Hydro asserts that, on balance, the differences in the criteria used to compare the options did not identify an option that was superior to the other options and therefore the lowest cost option was selected in each of the three segments. BC Hydro also states that statutory ROW, over both crown land and private land, will be required and BC Hydro will continue to work on the detailed engineering design and begin ROW acquisition to finalize the alignment in time for construction. (Exhibit B-1, pp. 4-9 to 4-14)

4.3.2 Route Update

On March 23, 2012 BC Hydro filed updated information regarding the route selection. It stated that "as the result of ongoing design work, the route has shifted slightly in some locations since the CPCN application was filed in July 2011." The three route segment maps in Exhibit B-1-3, Appendix D, (maps iv, v and vi) illustrate the following changes. (Exhibit B-1-3, p. 4-14)

(a) West Segment – East of Pine River Crossing – The route has shifted slightly further north resulting in a straighter line and less clearing.

(b) Central Segment – Groundbirch Area - during the route investigation, BC Hydro identified several sub-options in the Groundbirch area, and initially selected the route that maintained a straight east-west line. However, subsequent geotechnical investigations have shown that the ground is unstable in that area, so BC Hydro is reverting to a route that more closely follows the route of the existing 138kV transmission line.

(c) Central Segment - Kiskatinaw River Crossing – geotechnical investigations have shown that the ground may be unstable at the original planned river crossing, so a route north of the bridge is being investigated.

(Exhibit B-1-3, p. 4-14)

Subject to the above refinements BC Hydro proposes to build the 230 kV transmission line from SLS to BMT and from BMT to DAW using the Preferred Route Corridor as shown in Figure 4-3 above.

4.4 Existing 138 kV Line Decommissioning

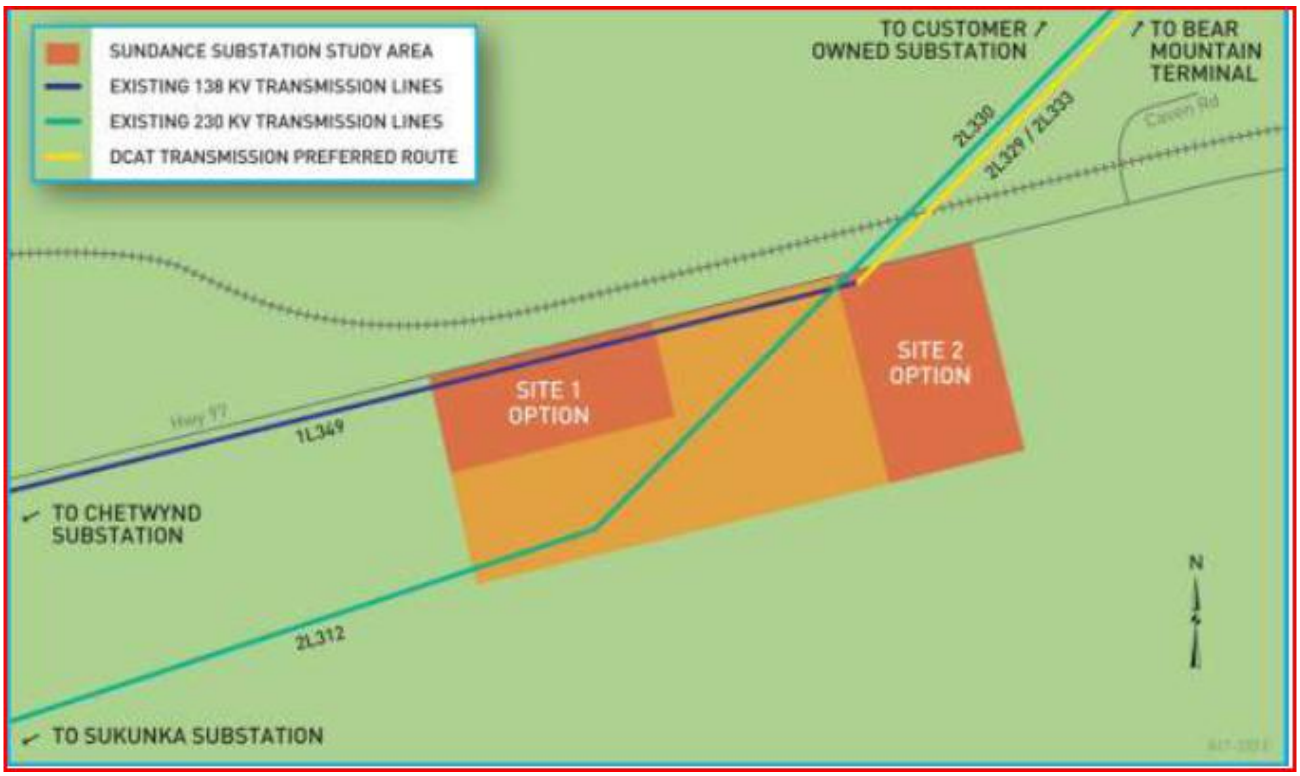
BC Hydro states that once the new 230 kV transmission lines are in place, the existing 1L362 and 1L358 lines will not be required to serve load in the Dawson Creek area. To minimize Project footprint and environmental fragmenting, and to reduce ongoing operations and maintenance costs, the lines, where 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. (Exhibit B-1, p. 4-15)

BC Hydro explained that retaining those portions of 138kV transmission lines that are designated for decommissioning would be undesirable because of the negative landowner impacts associated with maintenance activities, negative ratepayer impacts associated with maintaining the lines, and the cost of an attentive maintenance program and eventual replacement of the lines because they are approximately 40 years old. Therefore, in most cases, unneeded portions of transmission lines are decommissioned rather than retained for future use. (Exhibit B-5, BCUC 1.17.7)

4.5 Sundance Lakes Substation

BC Hydro explains "the proposed SLS substation, as shown in Figure 4-4 below, will be located at the intersection of circuits 2L312 and 1L358, and is required for interconnection of the 138 kV and 230 kV transmission systems, associated transformation and termination of the new 230 kV transmission lines." (Exhibit B-1, p. 4-15) BC Hydro further states it investigated two sites for location of SLS. The proposed Site 2 location, which is on Crown land, will not require re-routing of the existing transmission lines. SLS will require clearing and grading of an approximately 263 m x 324 m area to accommodate the ultimate size of the substation over the 30 year planning period (DCAT, GDAT and beyond). For the DCAT Project, the station itself will comprise a chain link fenced area of approximately 266 m x 218 m with a gravel surface inside the fenced area and extending 2 m outside the fence. A cleared buffer, approximately 29 m on the north and south, and 21 m on the east and west, will surround the fence. The north side of the substation will have an 80 m x 29 m parking area. A 20 m wide road/driveway will provide access to the substation from Highway 97. (Exhibit B-1-3, p. 4-16)

Figure 4-4 SLS Study Area and Site Options



Source: Exhibit B-1, p. 4-19

4.5.1 Technical Requirements

BC Hydro states SLS will be a 230/138 kV transformation station initially having the following:

- 4 x 230 kV line bays – two for in/out of 2L312[1] and two for the new 230 kV circuits 2L329 and 2L333 to BMT;
- 1 x 230/138 kV power transformer;
- 1 x 138 kV line bays for in/out of 1L358;[2]
- 230 kV and 138 kV circuit breakers
- Associated disconnect switches, surge arresters and instrument transformers;
- Standby diesel generator;
- Telecom tower; and
- Control building (10m x 20m).

For the DCAT Phase

(Exhibit B-1, pp. 4-15 to 4-16, B-1-3, p. 4-15)

BC Hydro notes the station is being developed to accommodate the ultimate planned configuration, including the following equipment:

- 4 x 230 kV line bay;
- 2 x 230 kV capacitor banks;
- 2 x 230/138 kV power transformers;
- 2 x 138 kV line bays;
- 2 x 138 kV capacitor banks;
- 2 x 138/25 kV power transformers; and
- 25 kV feeder section having 12 outgoing feeders.

For the GDAT and Future Phases

(Exhibit B-1, pp. 4 -16 to 4-17, B—1-3, p. 4-16)

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1 After the Project is in service, line 2L312 will be renamed to 2L312 for the section from SNK to SLS and 2L330 for the section from SLS to LAP.

2 Following decommissioning of a portion of 1L358, one bay would be available for future interconnection needs.

4.6 Bear Mountain Terminal Substation

4.6.1 Technical Description and Site Selection

BMT is located on the south side of Highway 97 approximately 12 km west of Dawson Creek as shown in Figure 4-5 below. Currently BMT is a four circuit breaker ring arrangement connected to 4 x 138 kV lines. The lines include 1L358 (to CWD), 1L362 (to DAW), 1L354 (to, Bear Mountain Wind Park) and 1L355 (privately owned line to oil and gas facilities). The dimensions of the existing station fence line are 66 m x 66 m. (Exhibit B-1, p. 4-19)

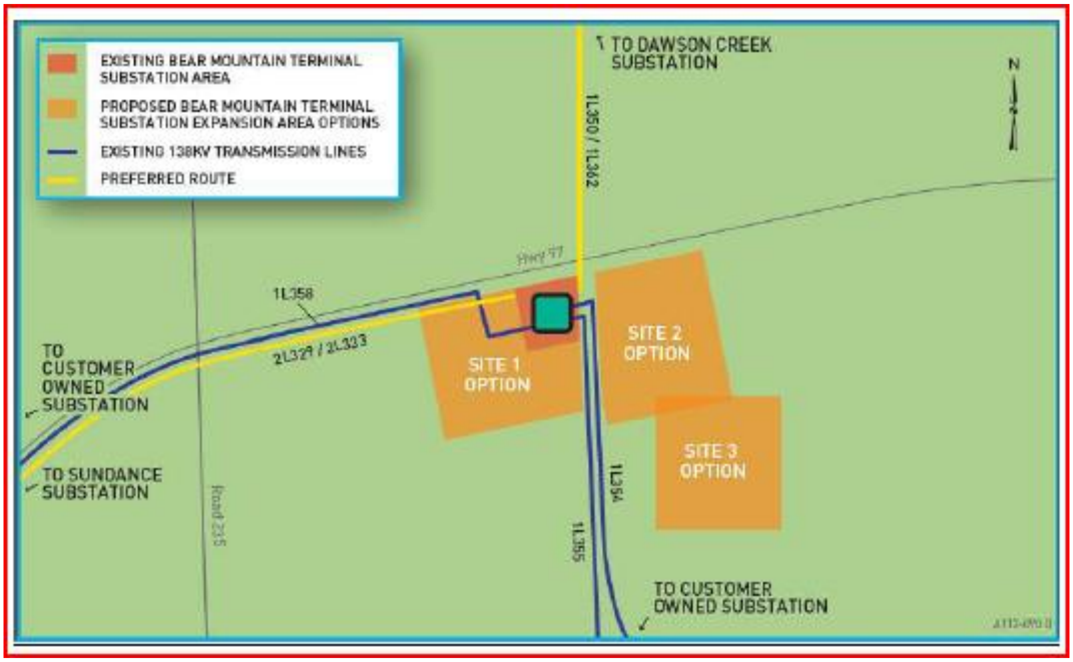
BC Hydro describes the BMT site requirements as:

• 2 x 230 kV line bays (for new lines to SLS); • 2 x 230/138 kV power transformers; • 2 x 138 kV line bays (for existing lines); • 1 x 138 kV line bay (for new line to DAW); • 1 x 138 kV line bay (provision for future).	For the DCAT Phase
• 3 x 230 kV line bays; • 2 x 230 kV capacitor banks; • 1 x 230/138 kV power transformers; • 1 x 138 kV line bay; • 2 x 138 kV capacitor banks; • 2 x 138/25 kV power transformers; and • 25 kV gas insulated switchgear feeder section.	For the GDAT and Future Phases

(Exhibit B-1-3, p. 4-20)

BC Hydro states that BMT is located in an area of privately owned properties and that it studied three options for the placement of the substation as shown in Figure 4-5.

Figure 4-5 BMT Expansion Layout Options



Source: Exhibit B-1-3, p. 4-21-A

BC Hydro notes that its evaluation of the three layout options considered a number of factors including land requirements, visibility, constructability, outages, safety and reliability, and cost. Option 1 is to expand to the west and south of BMT. Option 2 requires connections to the existing BMT station via overhead tie lines and underground control cable connections. Option 3 is to construct an entirely new station and dismantle the existing BMT.

Option 3 was determined to be infeasible due to its significantly higher cost and land requirements for the lines coming in and out of the station. Option 2 has a higher cost than Option 1, requires more land, and has the complications of the tie lines between the existing BMT and the expanded area that would result in construction complexities, additional construction outages, and live line work. Therefore, BC Hydro selected Option 1 as the preferred layout option for the BMT expansion because of the reduced cost, minimal land requirements, and reduced construction risk.
(Exhibit B-1-3, pp. 4-21-A, 4-21-B)

4.6.2 Submissions by Parties

CSI submits that if the proposed BMT expansion is to serve new load, the substation design team has not taken into account good planning practices relating to location selection. It stated that generally, a substation should provide power supply to all customers within a maximum of about 20 to 35 km radius. In contrast, CSI submits the proposed BMT expansion would require that each future customer build dedicated long lines (greater than 30 km) for service. On the other hand, if the main purpose of the substation design and planning was to provide service to the Bear Mountain Wind Power IPP (BMW), then CSI believes that the proposed substation is correctly located. Furthermore, DCAT planners terminated the 230 kV line at BMT as this is the point of interconnection with BMW and the substation is already owned by BC Hydro. For these reason's CSI submits it was expedient for BC Hydro to presume load customers would connect to the grid at this location, despite the distance from the major industrial load center. (CSI Final Submission, pp. 2-3)

In reply, BC Hydro submits there is no evidence to support this allegation and CSI's position ignores some key evidence. First, CSI seems to assume that all customers will be required to interconnect through the BMT substation. BC Hydro submits that is not correct. In several instances, points of interconnection are still being determined and the system reinforcement plan by BC Hydro will accommodate a broad variety of interconnection points. Some customers may choose to interconnect along the line rather than routing through a system substation and BC Hydro has not precluded those solutions where they are technically appropriate. The evidence demonstrates that Shell is considering that option and it may be available to other customers as they come forward. (BC Hydro Reply Submission, p. 11)

Second, BC Hydro submits more generally with respect to CSI's observations concerning BMT, there is no evidentiary basis for suggesting that the BMT expansion was chosen to accommodate the Bear Mountain Wind IPP. The evidence shows that the BMT expansion was carefully planned in the context of BC Hydro's normal planning process and BC Hydro's system planners concluded that at this time, expansion of that plant was the most effective way to address future needs. CSI has provided no basis to conclude otherwise. BC Hydro also points out that none of the customers that stand to be affected by this planning decision take any issue with the expansion of BMT. (BC Hydro Reply Submission, p. 12)

4.7 Dawson Creek Substation

BC Hydro states DAW is located on the western edge of the town of Dawson Creek, near Highway 97. Currently it is a 138/25 kV substation with 2 x 138 kV lines bays, 4 x 138kV capacitor banks, 3 x 138/25 kV power transformers, a 25 kV feeder section and 2 x 25 kV capacitor banks. The transmission lines currently connected to DAW include 1L362 (to BMT) and 1L377 (to TAY). (Exhibit B-1, p. 4-21)

BC Hydro describes the DAW configuration changes as:

• addition of a1 x 138 kV line bay;	DCAT
• 138 kV bus reconfigured to a ring arrangement;	
• 4 x 230 kV line bays;	Possible Future
• 2 x 230/138 kV power transformers.	Phases

BC Hydro states that the existing 1L362 will be decommissioned and a new 230 kV double circuit transmission line operated at 138 kV will be constructed on a new ROW for possible future conversion of the transmission lines from BMT to DAW substation to 230 kV. (Exhibit B-1, p. 4-2 and 4-15) Two private parcels located next to DAW were purchased in late 2010 to accommodate future station expansion. (Exhibit B-1, p. 4-22)

5.0 PROJECT ALTERNATIVES

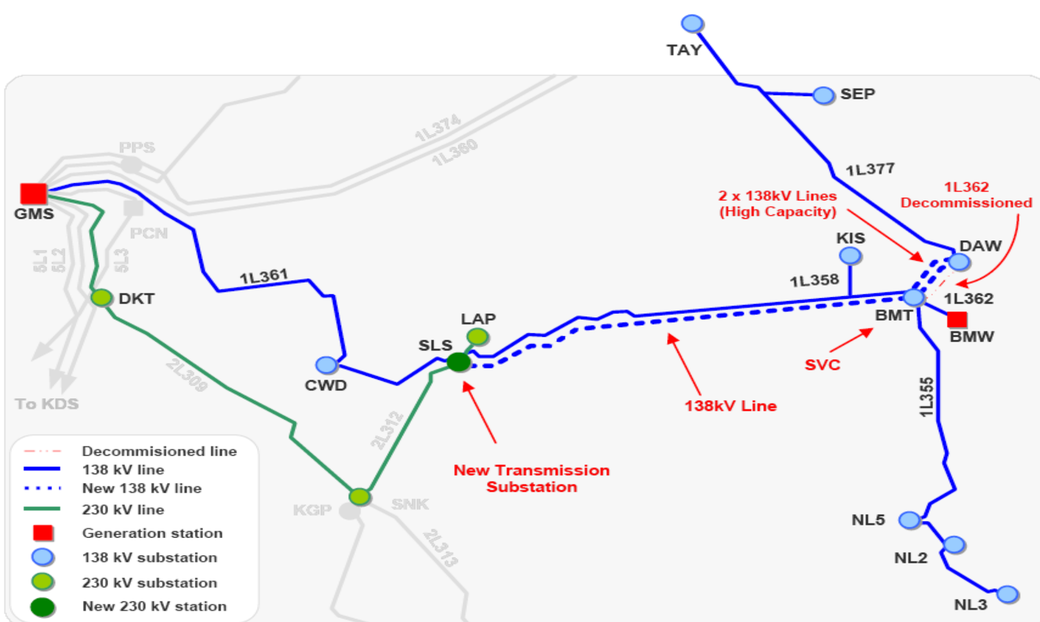
5.1 Introduction

In addition to the DCAT Project discussed in the previous section, BC Hydro provided an analysis for a number of alternatives to the proposed Project (Alternative 1) throughout the proceeding. This section reviews the alternatives analyzed by BC Hydro, with a view to determining whether the proposed Project is the appropriate alternative.

5.1.1 Alternative 2

Alternative 2 substitutes a 138kV transmission line between the proposed new SLS substation and BMT substation instead of a 230kV double circuit transmission line, with a static VAR compensator (SVC) at BMT. BC Hydro provides a technical description of Alternative 2 as shown in the following Figure 5-0.

Figure 5-0 Alternative 2: SLS-BMT 138kV Transmission Line

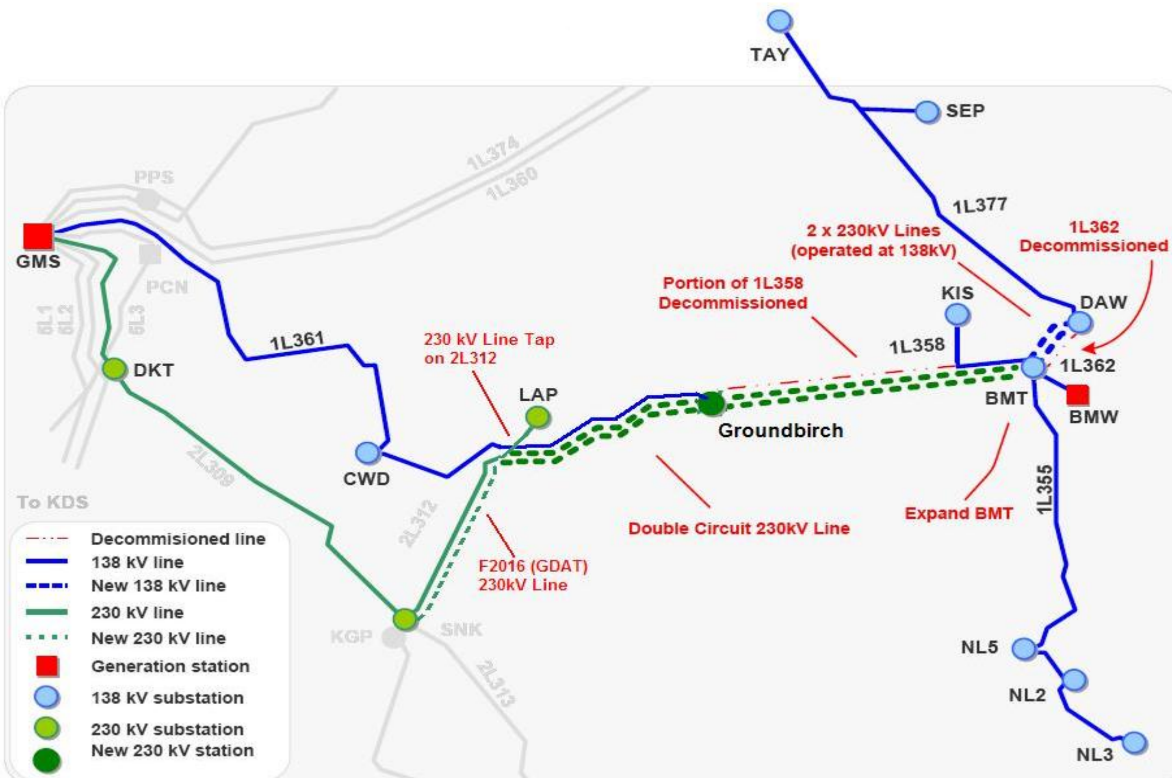


Source: Exhibit B-1, Figure 3-2, p. 3-6

5.1.2 Alternative B1

BC Hydro introduced Alternative B1 in response to a number of information requests, and its defining difference is the relocation of the proposed new SLS substation to the Groundbirch area. (Exhibit B-14, BCUC 2.1.1; Exhibit A-21, BCUC 3.2.1) The technical scope of Alternative B1 is summarized by BC Hydro and is reflected in the following figure:

Figure 5-1 Alternative B1

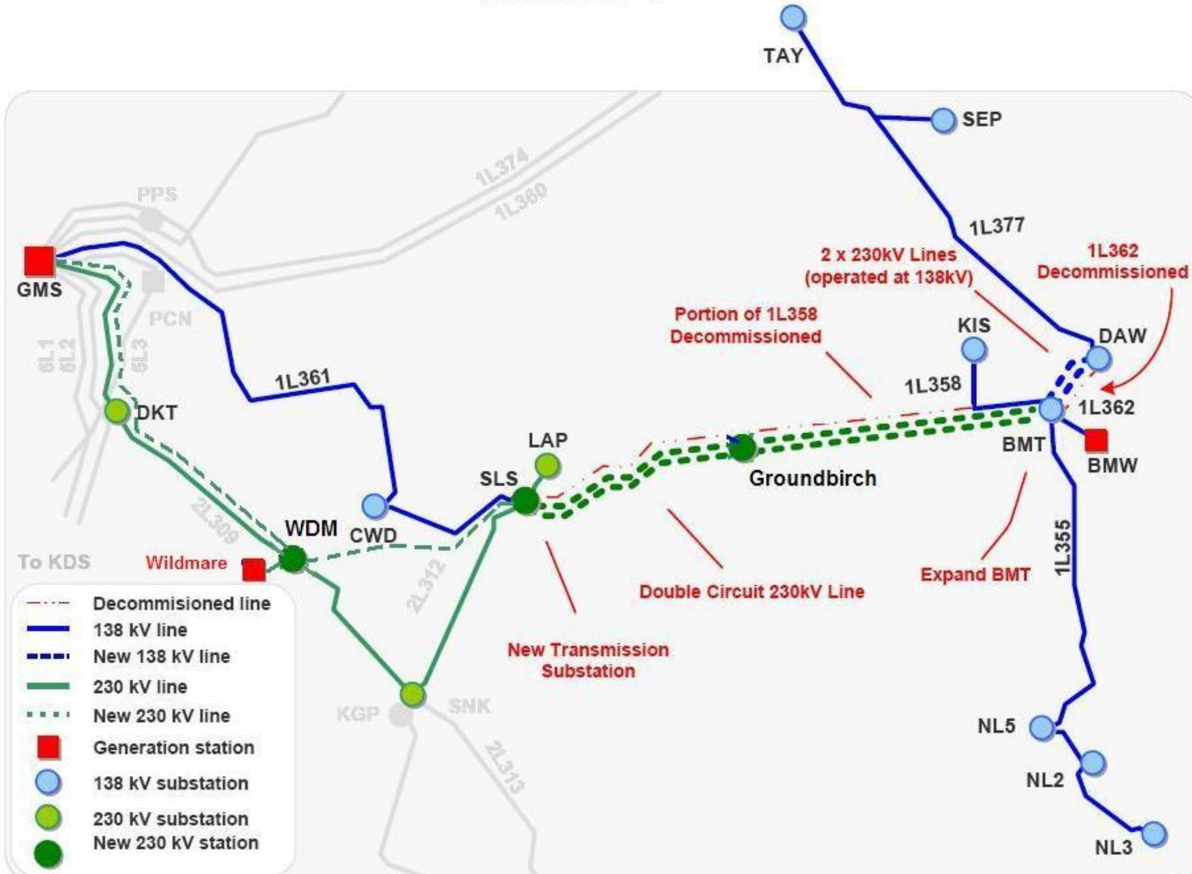


Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, p. 39-40

5.1.3 Alternative B2

Alternative B2 is identical to the proposed project in the DCAT phase. In the next phase (GDAT), the second 230kV transmission line source from the west to the proposed new SLS substation does not come from SNK substation, but rather from the proposed new Wildmare (WDM) substation. The scope of Alternative B2 as described by BC Hydro is shown in the following figure:

Figure 5-2 Alternative B2



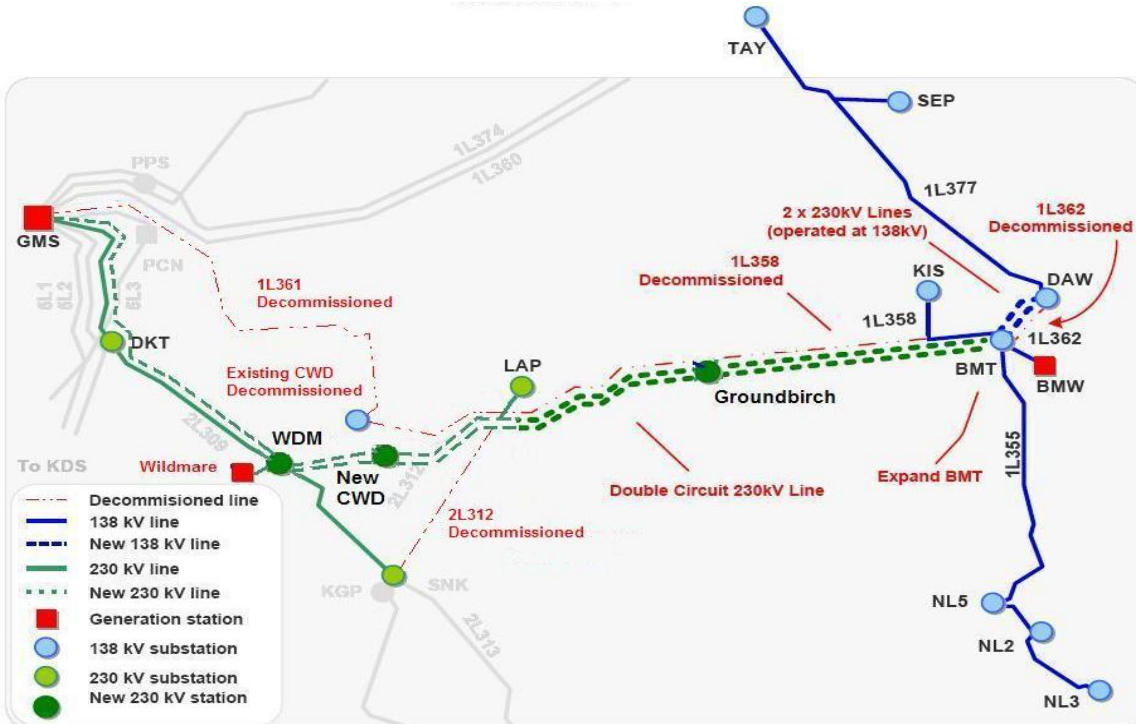
Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, p. 41

5.1.4 Alternative B3

In Alternative B3, the proposed new SLS substation is relocated to the Groundbirch area, and is supplied from the west by a 230kV double circuit transmission line from the proposed new WDM substation. The proposed new 230kV double circuit transmission line supplies both the LAP substation by way of a tap and a new 230kV/25kV substation at Chetwynd. This allows for the decommissioning of the existing CWD substation, the 138kV transmission lines 1L361 and 1L358, and the 230kV transmission line 2L312 between SNK substation and the tap point near the LAP substation.

As with Alternative B2, BC Hydro first provided an analysis for a configuration similar to Alternative B3 in the responses to the second round of information requests. (Exhibit B-14, BCUC 2.5.2, 2.8.1, 2.8.1.1) The scope of Alternative B3 as described by BC Hydro is shown in the following figure:

Figure 5-3 Alternative B3



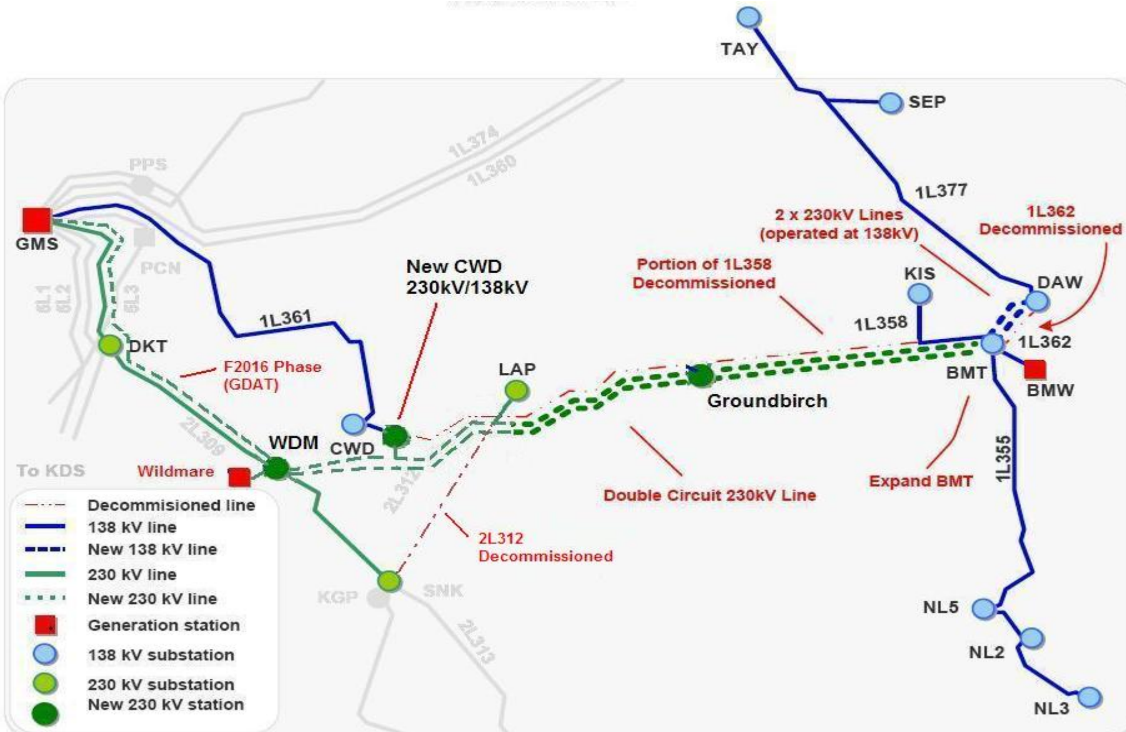
Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, pp. 42-43

5.1.5 Alternative B4

In Alternative B4, the proposed new SLS substation is relocated to the Groundbirch area, and is supplied from the west by a 230kV double circuit transmission line from the proposed new WDM substation. The proposed new 230kV double circuit transmission line supplies both the LAP substation by way of a tap and a new 230kV/138kV substation at Chetwynd, which in turn supplies the existing 138kV/25kV CWD substation. This allows for the decommissioning of the 138kV transmission lines 1L361 and 1L358, and the 230kV transmission line 2L312 between SNK substation and the tap point near the LAP substation.

BC Hydro introduced Alternative B4 in response to an information request. (Exhibit A-21, BCUC 3.4.1) The scope of Alternative B4 as described by BC Hydro is shown in the following figure:

Figure 5-4 Alternative B4



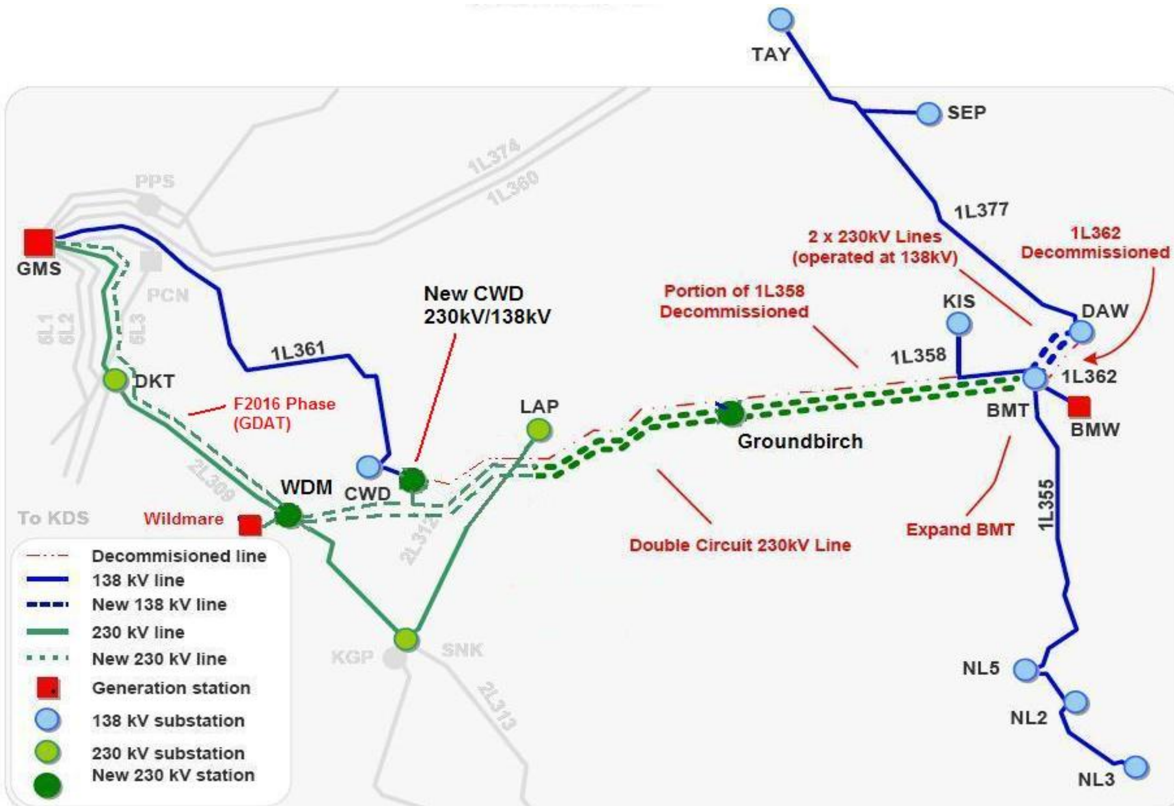
Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, pp. 44-45

5.1.6 Alternative B5

In Alternative B5, the proposed new SLS substation is relocated to the Groundbirch area, and is supplied from the west by a 230kV double circuit transmission line from the proposed new WDM substation. The proposed new 230kV double circuit transmission line also supplies a new 230kV/138kV substation at Chetwynd, which in turn supplies the existing 138kV/25kV CHW substation. This allows for the decommissioning of the 138kV transmission lines 1L361 and 1L358.

BC Hydro also introduced Alternative B5 in response to an information request. (Exhibit A-21, BCUC 3.4.1) The scope of Alternative B5, as described by BC Hydro, is shown in the following figure:

Figure 5-5 Alternative B5



Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, p. 46

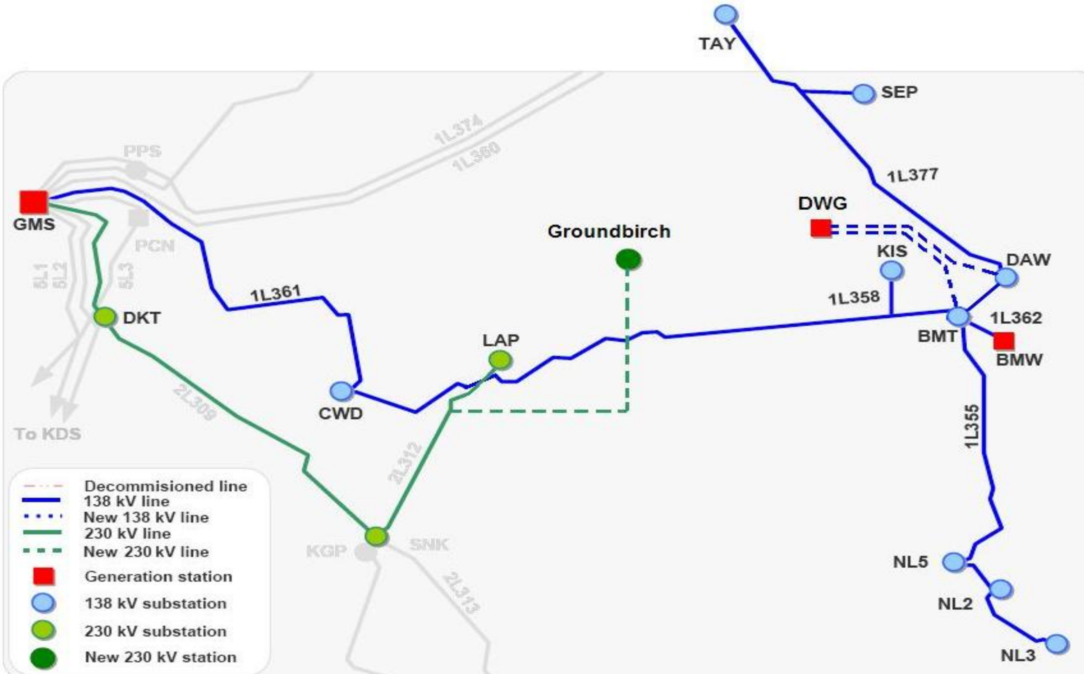
5.1.7 Alternative G1

In Alternative G1, none of the components of the proposed project remain. Instead, 150 MW of new gas-fired generation is installed near Dawson Creek and connected to the DAW and BMT substations by two new 138 kV transmission lines. A new single circuit 230 kV transmission line, tapped off transmission line 2L312 near LAP substation, supplies a new 230 kV substation in the Groundbirch area.

The scope of Alternative G1 is as follows:

- 150 MW of new gas-fired generation (three 50 MW combined cycle gas turbines (CCGT) units) at a new 138kV substation, Dawson Creek Generating Station (DWG);
- two new 6 km 138kV transmission lines from the proposed new DWG to BMT and the DAW substation;
- a new 30 km 230kV transmission line a tap on the 2L312 transmission line near LAP substation to a new 230kV customer substation in the Groundbirch area.

Figure 5-6 Alternative G1



Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, pp. 47-48

5.1.8 Alternative G2

In Alternative G2, as with Alternative G1, none of the components of the proposed project remain. Instead, 300 MW of new gas-fired generation is installed near Dawson Creek and connected to the DAW and BMT substations by two new 138 kV transmission lines. A new single circuit 230 kV transmission line from the new generation station supplies a new 230 kV substation in the Groundbirch area.

The scope of Alternative G2 is as follows:

- 300 MW of new gas-fired generation (four 50 MW CCGT units and one 100 MW single cycle gas turbine (SCGT) unit) at a new 230kV/138kV substation (DWG) near Dawson Creek;
- two new 6 km 138kV transmission lines from the proposed new DWG to BMT and the DAW substation;
- a new 30 km 230kV transmission line from the new DWG substation to a new 230kV customer substation in the Groundbirch area.

Figure 5-7 Alternative G2

Source: Exhibit B-1, Figure 3-2, p. 3-6; Exhibit B-22, Attachment 2, p. 48-49

5.1.9 Dismissed Alternatives

BC Hydro considers and dismisses a number of other options in addition to the alternatives identified above. The dismissed options include (Exhibit B-1, Appendix B, System Planning Report, Appendix A):

- Build a 138kV transmission line from TAY substation to DAW substation, a new 230kV/138kV SLS substation at the intersection of 2L312 and 1L358, and a 110 mega volt ampers reactive (MVAR) SVC at BMT;
- Build a 138kV double circuit transmission line from GMS to Chetwynd, and continue this 138kV double circuit transmission line along the 1L358 corridor up to the Groundbirch area, and from there, another 138 kV single circuit transmission line to BMT. This solution also required more than 200 MVAR of shunt compensation and the upgrading of the GMS 500kV/138kV transformers;
- Build a 230kV transmission line from TLR to 1L355 connected to a new 230kV/138kV substation, and construct a new 230kV/138kV SLS substation at the intersection of 2L312 and 1L358;
- Interconnection with Alberta, likely a 230kV transmission line would be required because of the forecast Dawson Creek and Groundbirch area loads;

- Power supply from Wind generation;
- Power supply from Site C.

BC Hydro states that it reviewed each of the alternatives and commissioned a detailed analysis of the gas generation alternatives, and concludes that the DCAT Project is still the preferred alternative. (Exhibit B-22, Attachment 2, p. 37) In most cases, including the preferred alternative, BC Hydro identifies the need for a further project in F2016, sometimes referred to as GDAT. (Exhibit B-22, Attachment 2, p. 38)

5.2 Evaluation Criteria

BC Hydro evaluated each of the alternatives using the following criteria: direct capital cost; transmission losses; Present Value (PV) cost; reliability; ROW and property requirements; and the earliest in-service date for the initial phase. In some cases the evaluation was quantitative, primarily for Alternative 2 and the generation-based alternatives. The majority of the evaluation for the remainder of the transmission-based alternatives was relative to the DCAT Project and not quantitative.

In addition to separately considering the direct capital cost and the value of transmission losses for each alternative, BC Hydro combined these costs into an overall present value cost that also took into account operation and maintenance costs and taxes. Fuel costs, greenhouse gas offset costs and energy and capacity credits were considered for the generation alternatives.

In order to compare the DCAT Project on an equal footing with the generation based alternatives, BC Hydro created a comparative portfolio consisting of the DCAT Project combined with a pro-rata portion of a 250 MW CCGT generation resource located on the integrated system in the Kelly-Nicola region. (Exhibit B-22, Attachment 2, p. 66)

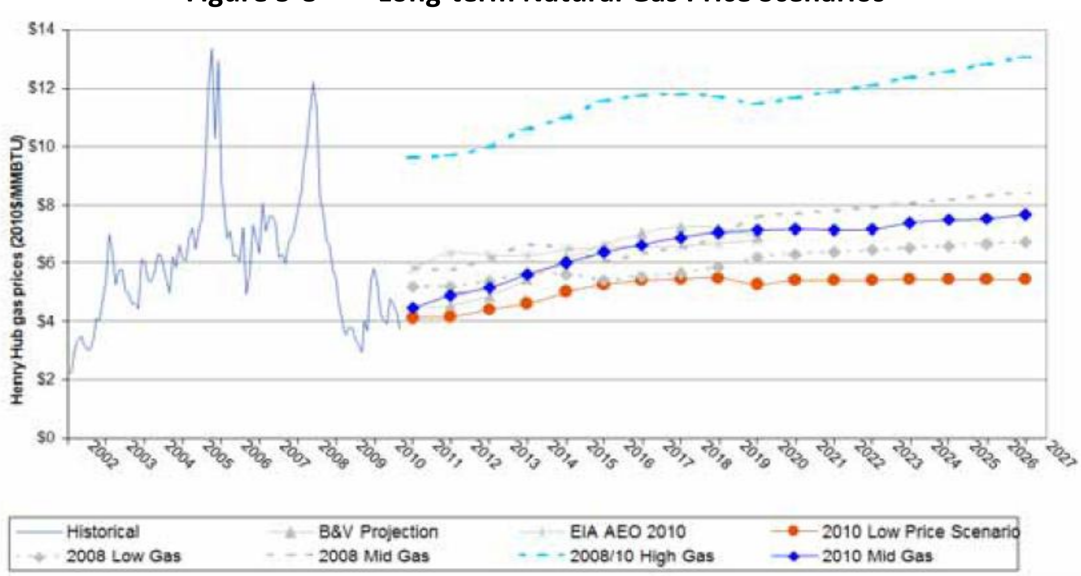
BC Hydro stated that since firm energy requirements consist of customers' load plus the loss incurred to deliver that energy, losses should be valued at the firm energy cost. (Exhibit B-6, CEC 1.26.2) As described earlier in this Decision, BC Hydro initially valued the incremental energy resources to serve DCAT Project area loads at the firm energy cost of $129/MWh, then changed the value to $116/MWh, and finally conditioned this value by stating that as long as the system is in a surplus condition, the forecast value of firm energy was $50/MWh and after the surplus is exhausted, the value is then $116/MWh. (Exhibit B-22, Attachment 2, pp. 36-37)

For decommissioned transmission line sections, BC Hydro initially stated the decommissioning and removal costs would be charged to operating costs and would not be capitalized. (Exhibit B-1, Appendix C, footnote 4) It revised that approach, however, and will now book these costs to the Future Removal and Site Restoration Account. (Exhibit B-1-3, Appendix C, Revision 2, footnote 4)

For the generation based alternatives, BC Hydro performed an analysis that considered fixed and variable Operating and Maintenance (O&M) costs for both the alternatives and the 250 MW CCGT that was added to the DCAT Project portfolio. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2) BC Hydro considers two natural gas price scenarios, a "mid" scenario at $7/GJ and a "low" scenario at $5/GJ, both referenced to Station 2. (Exhibit B-22, Attachment 2, p. 64) Allowances for GHG offset costs were included in the evaluation.

BC Hydro relied on the long-term natural gas price scenarios being used in development of its draft IRP, and reproduced below:

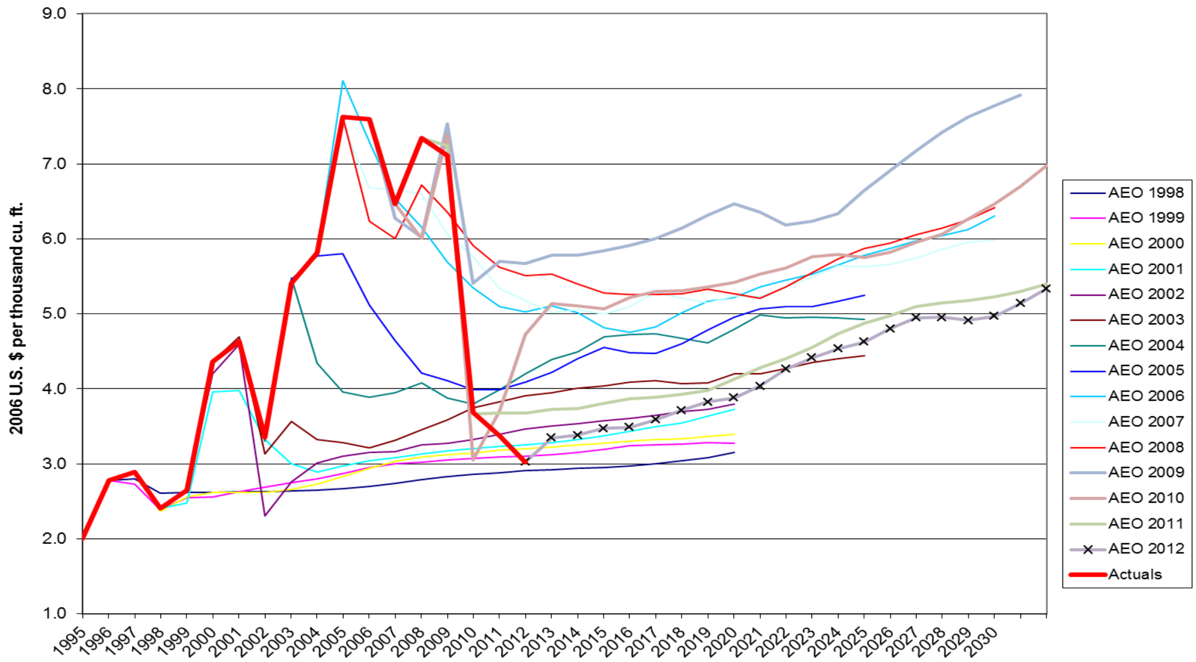
Figure 5-8 Long-term Natural Gas Price Scenarios



Source: Exhibit B-30, AMPC 4.1.1

BC Hydro stated that it maintains the above scenarios but the low price scenario has been afforded a greater weighting than it had when the 2010 Load Forecast was created. BC Hydro provided a summary of past natural gas price forecast that shows a pronounced trend of lower future prices for more recent forecasts as compared to older forecasts. (Exhibit B-30-1, CEC 4.14.2) This summary is reproduced below in Figure 5-9.

Figure 5-9 Forecasts of Natural Gas Prices U.S. ave. Wellhead Prices



Source: Exhibit B-30-1, CEC 4.14.2

As was described in Section 3.6.1 of this Decision, the BC Hydro system is in a capacity deficit position as early as F2017 even without additional LNG loads. BC Hydro recognized the addition of system capacity associated with the generation based alternatives and the comparative DCAT Project portfolio, as compared to the transmission based alternatives that did not provide any additional capacity. A benefit was attributed to the options that added dependable capacity to the BC Hydro system. Dependable capacity was credited at the unit capacity cost (UCC) of Revelstoke Unit 6 (Exhibit B-22, Attachment 2, p. 64) which is $55/kW-yr in $2011. (Exhibit B-30-1, CEC 4.17.3)

BC Hydro also assessed each of the alternatives for the ability to satisfy the N-1 planning standard with regard to capacity and timing.

5.3 Evaluation of Alternatives

BC Hydro summarizes its assessment of all the alternatives in Table 10 of Exhibit B-22, Attachment 2, reproduced below:

Table 5.1 Project Alternatives

Table 10 Comparison Summary

Alternative	Direct Capital Cost	Transmission Losses	PV Cost (including losses O&M and taxes)	Reliability	Right-of-Way and Property Requirements	Earliest In-Service Date (Initial Phase)
DCAT Project Alternative 1 (DCAT 1)	Base	Base	Base	Base	Requires new substation site and new and widened ROW	Early F2015
Alternative 2 (DCAT 2)	Lower than DCAT 1	Higher than DCAT 1	Same as* DCAT 1	Lower than DCAT 1	Similar to DCAT 1	F2016
B1 – No SLS	Lower than DCAT 1	Higher than DCAT 1	Lower than DCAT 1	Lower than DCAT 1	Similar to DCAT 1	Late F2015
B2 – WDM with SLS	Lower than DCAT 1	Similar to DCAT 1	Lower than DCAT 1	Similar to DCAT 1	Same as DCAT 1 plus additional substation expansion. Less new and widened ROW in Phase 2.	Early F2015
B3 – WDM w/o SLS	Not a feasible alternative					
B4 – WDM with LAP tap	Higher than DCAT 1	Similar to DCAT 1	Higher than DCAT 1	Lower than DCAT 1	Similar to B2 (but note decommissioning)	F2017
B5 – WDM with LAP radial	Higher than DCAT 1	Similar to DCAT 1	Higher than DCAT 1	Lower than DCAT 1	Similar to B2 but additional ROW required for initial build.	F2017
G1	Higher than DCAT 1	Lower than DCAT 1	Higher than DCAT 1	Lower than DCAT 1	Requires one generation site and some new ROW	F2016 to F2018
G2	Higher than DCAT 1	Lower than DCAT 1	Higher than DCAT 1	Lower than DCAT 1	Requires one generation site and some new ROW	F2016 to F2018

* Table analysis does not consider the updated load forecast which will result in higher losses in Alternative 2 relative to the DCAT Project.

Source: Exhibit B-22, Attachment 2, p. 72

BC Hydro submits Alternative 1 has a lower present value cost, provides superior energy transfer capability to serve the load growth, extra capacity to accommodate greater economic development, lower losses, greater reliability, lower footprint with fewer structures and greater reclamation from decommissioning as compared to Alternative 2 and is therefore the preferred alternative. (BC Hydro Final Submission, pp. 13-15)

In addition, BC Hydro submits the DCAT Project will be able to provide service to its existing customers by April 30, 2014 (assuming a CPCN is issued by the end of September, 2012), and even still, it appears that several customer plants will be awaiting BC Hydro service by that date. BC Hydro reminds the Commission that it must consider and be guided by the government's objective for BC Hydro to develop adequate electricity transmission infrastructure in time to serve these customers and that the ability of the DCAT Project as proposed to provide service sooner than most other alternatives is a significant factor in its favour. (BC Hydro Final Submission, p. 14)

BCPSO submits the apparent Net Present Value (NPV) cost advantage of the DCAT Project is not firm and is dependent upon the load forecast chosen. BCPSO claims the evidence shows that the NPV advantage of the DCAT Project over Alternative 2 disappears if the Dawson Creek area load forecast is reduced by only 15 percent, and the load forecast assumptions, particularly over the longer term, are critical to justify the choice of Alternative 1 as the preferred alternative. BCPSO remains unconvinced that the forecast relied upon is reasonable in these circumstances. (BCPSO Final Submission, p. 10)

CEC submits that the DCAT Project is the least cost option which can be delivered in a reasonable time to meet the needs of the area customers. (CEC Final Submission, p. 5)

5.3.1 Alternative 2

The lower direct capital costs of Alternative 2 as compared to the DCAT Project are attributable to the construction of 138 kV transmission lines instead of 230 kV double circuit transmission lines, but the compromise of the lower cost is reduced maximum capability of Alternative 2 as compared to the DCAT Project. (Exhibit B-1, pp. 3-8, 3-9)

BC Hydro provides a detailed analysis of system losses for the DCAT Project and Alternative 2. (Exhibit B-1, Appendix B, p. 53) The original analysis shows that Alternative 2 has higher losses than the DCAT Project for all years. In its update, BC Hydro states that as a result of the increased peak load of the updated load forecast, the transmission losses of Alternative 2 would increase more relative to the DCAT Project because losses on the 138 kV system would be higher but BC Hydro does not quantify this increase. (Exhibit B-22, Attachment 2, p. 50) However, the decrease in the value of losses because of the lower cost of energy in system surplus conditions appeared to significantly reduce the overall cost of the losses for Alternative 2. Alternative 2 had a lower PV for O&M and taxes than the DCAT Project by approximately $3 million. (Exhibit B-5, spreadsheet attachment to BCUC 1.54.4)

BC Hydro provides a detailed evaluation and comparison of the present value cost of the DCAT Project and Alternative 2, as summarized in the table below:

Table 5.2 Present Value (PV)

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

Source: Exhibit B-1, p. 3-8

In its update, BC Hydro states that the total PV cost of the DCAT Project and Alternative 2 are now approximately the same, principally due to the change in the cost of energy that was applied to transmission losses, but no quantitative data is provided. (Exhibit B-22, Attachment 2, p. 50)
BC Hydro cautions the update evaluation was performed using the original load forecast, and the higher loads in the updated load forecast would be directionally worse for Alternative 2 as compared to the DCAT Project because losses would increase faster for Alternative 2.

BC Hydro further states that the DCAT Project demonstrates better reliability performance than Alternative 2, primarily based on lower Expected Energy Not Served (EENS) values as shown in the table below:

Table 5.3 Expected Energy Not Supplied Comparison in MWh/year

	Cumulative EENS* (mwH/30year)
Alternative 1	40,000
Alternative 2	45,000

Source: Exhibit B-1, p. 3-10

However, the post-contingency supply capability of Alternative 2 is 207 MW (Exhibit B-1, Appendix B, p. 46), which is greater than that for the DCAT Project at 185 MW. (Exhibit B-1, Appendix B, p. 42) Nevertheless, BC Hydro claims that the DCAT Project is more capable of meeting a higher load forecast than Alternative 2 (Exhibit B-22, Attachment 2, p. 50), but presumably only after the Phase 2 GDAT upgrades. BC Hydro provides further supply capability performance for both alternatives following the Phase 2 GDAT project. (Exhibit B-1, p. 3-10) The capability of the system for both the DCAT Project and Alternative 2 with all elements in service (N-0) is about 405 MW. (Exhibit B-14, BCUC 2.17.1; Exhibit B-30, BCPSO 4.1.1)

BC Hydro provides a comparison of the land impacts of DCAT Project and Alternative 2. (Exhibit B-1, pp. 3-11, 3-12) For substation land requirements, the additional 230kV/138kV transformers at BMT for the DCAT Project result in a slightly greater footprint requirement at BMT than Alternative 2. The substation requirements at DAW and SLS are similar for both options. Alternative 2 has less transmission requirement than the DCAT Project, because although the same number of ROWs are required for both alternatives, those for Alternative 2 are not as wide because the transmission lines are 138 kV. BC Hydro states that differences pertaining to station and right-of-way land impacts were not material factors in selecting a preferred alternative.

Interveners Marilyn and Gary Robinson provided evidence that BC Hydro's requirements at the BMT substation would exceed commitments allegedly made by BC Hydro when it first acquired rights over the Robinson's property in 2008 and 2009. (Exhibit C11-6, pp. 2-3) BC Hydro states that it has addressed the Robinson's Information Requests, but that information has not been made available in the proceeding record. (Exhibit B-22, Attachment 2, p. 89)

Finally, in the update, BC Hydro states that the construction of Alternative 2 could not meet the required in-service date. (Exhibit B-22, Attachment 2, p. 50)

5.3.2 Alternative B1

BC Hydro addresses elements of Alternative B1 that appear to be associated with the future upgrades in F2016, also referred to as GDAT. BC Hydro states that in the F2016 stage, a second 230kV transmission line would be required between SNK and the tap point on 2L312, and that a transmission route would have to be determined. (Exhibit B-22, Attachment 2, pp. 39-40)

In its evaluation, BC Hydro states that Alternative B1 requires fewer 230kV circuit breakers than the proposed project, but results in an extra 20 km of 138kV transmission line being retained, alongside a new 230kV double circuit transmission line between the intersection of 2L312 and 1L358 and the Groundbirch substation. (Exhibit B-22, Attachment 2, p. 40)

Alternative B1 has a lower direct capital cost than the DCAT Project, primarily because of the reduced amount of station facilities associated with the elimination of the SLS substation. (Exhibit B-22, Attachment 2, p. 51) During the planning stage, BC Hydro had insufficient information to define the location for a single substation in the Groundbirch area, so it elected to proceed with a two substation configuration, that, while more expensive, offered greater flexibility.

Although BC Hydro does not provide a quantitative PV comparison with the DCAT Project, it acknowledges that the PV cost of Alternative B1 is lower than that of the proposed Project because of lower direct capital cost arising from relocation of the proposed new SLS substation to the Groundbirch area, even when the higher losses of Alternative B1 are considered. (Exhibit B-22, Attachment 2, p. 51) BC Hydro rejected Alternative B1 during the planning stage because it was unable to obtain sufficient information from the customer in the Groundbirch area about the location of new loads to allow it to locate a site for a single substation. BC Hydro now has greater certainty of both the location of Groundbirch area loads and the new substation, but states the new Groundbirch substation site would likely not accommodate all the SLS facilities. Furthermore, BC Hydro states its analysis shows Alternative B1 to have a larger footprint and potentially lower transmission system reliability than the DCAT Project. (Exhibit B-22, Attachment 2, pp. 51-52)

BC Hydro claims that Alternative B1 had lower reliability than the DCAT Project because only one substation would be built, causing the service to LAP substation to be less robust because of a tap connection to transmission line 2L312, which in turn would also cause uneven loading on the transmission lines. (Exhibit B-22, Attachment 2, p. 52)

BC Hydro states Alternative B1 has a larger footprint than the DCAT Project because the footprint reduction associated with one substation instead of two is more than offset by the need to retain an additional 20 km of the existing 1L358 138kV transmission line between the proposed sites of the SLS substation and the Groundbirch substation. (Exhibit B-22, Attachment 2, p. 52) BC Hydro asserts that the potential site for the Groundbirch substation may not be able to accommodate the combined SLS and Groundbirch substation facilities and equipment.

BC Hydro does not provide an assessment of timing differences for Alternative B1 other than the summary table in the update, which identifies a "Late F2015" (Exhibit B-22, Attachment 2, p. 72) in-service date as compared to "Early F2015" for the DCAT Project.

5.3.3 Alternative B2

BC Hydro again addresses elements of Alternative B2 that appear to be associated with future upgrades in F2016, and compares these to the DCAT Project. (Exhibit B-22, Attachment 2, p. 41) BC Hydro states the F2014 phase of Alternative B2 is identical to the DCAT Project and that the studies for the F2016 stage are still ongoing and will consider the second phase 230 kV transmission line routing as suggested in Alternative B2. (Exhibit B-22, Attachment 2, p. 53)

The lower direct capital cost of Alternative B2 as compared to the DCAT Project (Exhibit B-22, Attachment 2, p. 72, Table 10) refers to the F2016 phase of the project, because the first phase is identical to both. (Exhibit B-22, Attachment 2, p. 53)

BC Hydro does not provide much comment with respect to the performance characteristics of Alternative B2, but since the configuration of the first phase is identical to the DCAT Project, any differences will only arise at the F16 phase. Therefore, the losses, the O&M and tax costs, the total

PV, the reliability, the land impact, and the timing of Alternative B2 are the same as the DCAT Project. BC Hydro does not provide any comparisons regarding the second phase associated with each alternative other than a potential lower cost associated with Alternative B2. (Exhibit B-22, Attachment 2, p. 53)

5.3.4 Alternative B3

BC Hydro states Alternative B3 is not practical because it eliminates a 138kV transmission line (1L361) which would need to be replaced in the near future because the transmission lines proposed in the F2016 stage of upgrading would not be able to provide post-contingency service to the load in the Tumbler Ridge, Chetwynd, Groundbirch and Dawson Creek areas by F2017 or F2018. (Exhibit B-22, Attachment 2, p. 43) BC Hydro claims the solution to this problem is another transmission line either between GMS and WDM or between TAY and DAW. BC Hydro does not provide any comparative analysis for Alternative B3 versus the DCAT Project because Alternative B3 is considered to be not feasible.

5.3.5 Alternative B4

Alternative B4 has higher direct capital costs than the DCAT Project, at least in the first phase, primarily because of the construction of an additional 30 km of new 230kV double circuit transmission line. (Exhibit B-22, Attachment 2, p. 54) Although BC Hydro acknowledges that Alternative B4 required less 230kV transmission line for future upgrades, BC Hydro does not provide any detailed analysis to support its conclusion that direct capital costs would remain higher for Alternative B4, the estimates for which were “order of magnitude” estimates.

BC Hydro stated that the existing CWD substation would not accommodate a new 230 kV line termination and a 230kV/138kV transformer, and that a new site would be required for the 230kV/138kV facilities. (Exhibit B-14, BCUC 2.5.2)

BC Hydro further stated the losses for Alternative B4 were similar to the DCAT Project, but did not provide any support for this comparative statement. (Exhibit B-30, BCUC 4.4.9) Neither did

BC Hydro provide specific comment regarding the change in losses for supplying the CWD substation with a close-coupled 230kV supply rather than a 138 kV transmission line. (Exhibit B-30, BCUC 4.4.6, 4.4.6.1)

BC Hydro does not provide any assessment of the PV of O&M and taxes for Alternative B4. BC Hydro does not provide quantitative total PV comparisons between the DCAT Project and Alternative B4 and states only that Alternative B4 has a higher total PV cost than the DCAT Project because of higher "order of magnitude" estimated direct costs. (Exhibit B-22, Attachment 2, p. 54)

BC Hydro claims Alternative B4 has a lower level of reliability than the DCAT Project, particularly as to the effects on the supply to LAP substation and the Tumbler Ridge region. (Exhibit B-22, Attachment 2, p. 54; Exhibit B-30, BCUC 4.4.7)

BC Hydro states that Alternative B4 requires an additional 30 km of new 230 kV double circuit transmission line in Phase 1 as compared to the DCAT Project. (Exhibit B-22, Attachment 2, p. 54) BC Hydro goes on to say that less right-of-way is required for Alternative B4 for future upgrades, but does not provide any quantitative assessment.

Finally, BC Hydro states that Alternative B4 would not meet the required in-service date (Exhibit B-22, Attachment 2, p. 54), and states that the alternative was dependent on the construction of the WDM substation, scheduled for July 2014. BC Hydro identifies a "F2017" (Exhibit B-22, Attachment 2, p. 72, Table 10) in-service date for Alternative B4 as compared to "Early F2015" for the DCAT Project, but does not provide any further support of this schedule.

5.3.6 Alternative B5

BC Hydro stated that the only difference between Alternative B4 and Alternative B5 was that 2L312 would continue to serve the LAP substation from SNK in Alternative B5. Therefore the constraint of the existing CWD substation to accommodate new 230kV facilities would be the same as for Alternative B4 and a new site would be required for the new 230kV/138kV facilities. (Exhibit B-14, BCUC 2.5.2)

BC Hydro did not identify any other differences between Alternatives B4 and B5, so the evaluation of Alternative B5 as compared to the DCAT project is identical to the evaluation of Alternative B4.

BC Hydro does not provide any assessment of the PV of O&M and taxes for Alternatives B1, B3, B4 or B5. Alternative B2 has the same infrastructure as the DCAT Project in the first phase, so the O&M and taxes should also be the same.

5.3.7 Generation Based Alternatives

Early in the proceeding, BC Hydro claimed that gas-fired generation solutions would not be in the interest of ratepayers because 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. (Exhibit B-6, CEC 1.38.1) Later, BC Hydro claimed it had not examined or evaluated natural gas generation alternatives within the Dawson Creek and Groundbirch areas. (Exhibit B-15, CEA 2.5.4) Nevertheless, BC Hydro introduces two gas-fired generation alternatives, Alternatives G1 and G2, in Exhibit B-22.

The direct capital costs of both Alternatives G1 and G2 are higher than the DCAT Project, but a detailed capital cost estimate was not provided by BC Hydro for these alternatives. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2)

To compare the DCAT Project on an equal footing with the generation based alternative, BC Hydro creates a portfolio consisting of the DCAT Project and a pro-rata portion of a 250 MW CCGT generation resource located on the integrated system in the Kelly-Nicola region. In the comparison of the generation based alternatives with the DCAT Project, BC Hydro also added a gas tolling charge to the DCAT Project portfolio for delivery of gas to this region. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2)

The effect of this capital cost assignment strategy is that the PV of the three 50 MW CCGT units for Alternative G1 is $411 million, while the pro-rata portion of the 250 MW CCGT assigned to the DCAT Project alternative is only $183 million. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2) This results in the PV of the capital cost of Alternative G1 as being $228 million greater than the identically-sized generation component cost assigned to the DCAT Project.

The capital cost difference is even greater for Alternative G2, which has a capital cost PV of $630 million associated with the four 50 MW CCGT units and the single 100 MW SCGT (total 300 MW). The full capital cost (with a PV of $294 million) of the 250 MW CCGT was assigned to the DCAT Project. No additional cost was assigned to the DCAT Project for the 50 MW difference compared to Alternative G2. The PV of the capital cost of Alternative G1 is $336 million greater than the generation cost assigned to the DCAT Project.

BC Hydro also added an additional $13 million (PV of $12 million) to each of the generation based alternatives for generator interconnection cost, but there was no interconnection cost added to the DCAT Project portfolio for the 250 MW CCGT. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2)

BC Hydro quantifies the transmission losses for the DCAT Project for the comparison against the generation based alternatives, but BC Hydro does not specify whether the quantified DCAT Project losses also include the losses for the 138kV transmission lines between DAW, BMT and KIS because BC Hydro qualifies the analysis by stating the quantified DCAT Project losses are “230 kV transmission losses”. (Exhibit B-22, Attachment 2, p. 63) Since the generation based alternatives rely heavily on the existing 138 kV infrastructure, it is presumed those losses do include the 138kV transmission lines. BC Hydro states that both generation based alternatives have lower losses than the DCAT Project. However, in the evaluation, BC Hydro assigned a “losses credit” to the DCAT Project portfolio for reduced energy flow between the project area and the Kelly-Nicola area where the DCAT Project portfolio’s 250 MW CCGT would be situated. After the application of this “losses credit” the DCAT Project portfolio has lower overall losses than Alternative G1, but remains higher than Alternative G2. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2)

For the generation based alternatives, BC Hydro performed an analysis that included fixed and variable O&M costs for both the alternative and the 250 MW CCGT that was added to the DCAT Project portfolio. (Exhibit B-30-1, spreadsheet attachment to CEC 4.26.2) In the case of Alternative G1, the PV of the fixed and variable O&M was $219 million compared to $87 million for the 150 MW pro-rata portion of the DCAT Project portfolio's 250 MW CCGT. In the case of Alternative G2, the PV of the fixed and variable O&M was $311 million compared to $131 million for the full amount of the DCAT Project portfolio's 250 MW CCGT.

BC Hydro provides reasonably detailed PV cost evaluation for the generation based alternatives. BC Hydro claims the DCAT Project portfolio provides a lower PV cost than either generation based alternative as shown in the table below:

Table 5.4 Comparison Summary

Summary of PV Cost Differences ($M 2012)
(Gas Alternative Cost - DCAT Scenario Cost)

	mid	low
	1	2
Alt. G1 vs. DCAT Scen. 1	$93	$88
Alt. G2 vs. DCAT Scen. 2	$227	$207

Source: Exhibit B-22, Attachment 2, p. 68

In the table above, the "mid" and "low" columns represent BC Hydro's "mid" and "low" natural gas price forecasts, DCAT Scenario 1 is a 150 MW pro-rata portion of a 250 MW CCGT in the Kelly Nicola region, and the DCAT Scenario 2 is the allocation of the whole 250 MW CCGT. BC Hydro again cautions that the update evaluation is performed using the original load forecast, and the higher loads in the updated load forecast would be directionally worse for the generation based alternatives as compared to the DCAT Project because expanding generation local to the Dawson Creek area would be more costly than expanding supply on the integrated BC Hydro system.

The selection of the CCGT and SCGT sizes for the generation based alternatives was driven by reliability considerations. BC Hydro explains that in transmission-constrained regions, such as the Dawson Creek area, adding local gas-fired generation would require the installation of relatively small units (e.g., 50 to 75 MW) in order to have redundancy such that an acceptable level of reliability can be achieved. (Exhibit B-22, Attachment 2, p. 55) However, the use of small gas-fired units, results in cost inefficiencies compared to larger units because of higher unit capital costs (e.g., typically $3000/kW for a 50 MW CCGT vs. $1450/kW for a 250 MW CCGT).

BC Hydro's reliability analysis of the generation based alternatives shows that the DCAT Project portfolio has better reliability than either one, based on EENS results. (Exhibit B-22, Attachment 2, p. 63) BC Hydro states Alternative G2 has better reliability than Alternative G1 because the latter only provides N-0 service to the Groundbirch area. (Exhibit B-22, Attachment 2, p. 64)

The N-1 capability of Alternative G1 is approximately 220 MW, because each of the three 50 MW CCGT's is smaller than the largest transmission contingency of 80 MW. (Exhibit B-22, Attachment 2, p. 61) The 220 MW capability comes from the three 50 MW CCGTs plus the 70 MW N-1 capability of the existing transmission system. The N-1 capability of Alternative G2 is approximately 350 MW, because the 100 MW SCGT becomes the dominant contingency, which allows the N-0 capability of the existing transmission system to be used. (Exhibit B-22, Attachment 2, pp. 61-62) The 350 MW capability comes from the four 50 MW CCGTs plus the 150 MW N-0 capability of the existing transmission system.

BC Hydro does not provide either a qualitative or quantitative assessment of land impacts for the generation based alternatives, aside from identifying the need for a new generation site and rights-of-way for associated transmission lines (Exhibit B-22, Attachment 2, p. 72), nor is there any comparison provided with the DCAT Project.

For the generation based alternatives, BC Hydro states that its assumption of a five year implementation period for either a CCGT or SCGT could be decreased somewhat through advanced planning and expedited approvals. Even with reduced lead times, it states the earliest practical implementation date for a CCGT is F2017 and for a SCGT is F2016. (Exhibit B-22, Attachment 2, pp. 60-61) BC Hydro also states the generation based alternatives could not meet the expected Dawson Creek area load growth in the near term to the same degree as the DCAT Project, and would result in significant load service shortfalls in years F2016 and F2017.

BCPSO asserts serious flaws exist in BC Hydro's insistence upon a gas-on-gas comparison and furthermore that it is disingenuous for BC Hydro to assume for the purposes of the economic comparisons with gas-fired generation, that the energy supplied to the area for the DCAT Project portfolio will be sourced from natural gas. BCPSO claims that if the comparison of the cost of the DCAT Project portfolio is made with the two alternate sources of energy, the gas-fired alternative has the lower net present value. (BCPSO Final Submission, p. 12)

CEC submits the evidence shows that local generation might well provide a lower cost option providing service at the N-1 standard with lower long term transmission cost investment, but that the local generation options using natural gas fuel for generation are not the optimal location for the limited amount of natural gas fuelled generation which BC Hydro may have available within its overall portfolio. CEC also claims that building a local generation option in a reasonable timeframe to avoid the more expensive DCAT Project would not be possible. (CEC Final Submission, p. 5)

In reply, BC Hydro counters that there is no "serious flaw" in its analysis as suggested by BCPSO and that using the cost of new clean energy would not provide a helpful comparison because BC Hydro's new forecast arising from the revised Electricity Self Sufficiency Regulation and SD No. 10 suggests the system has, and will continue to have, surplus capacity for several years. (BC Hydro Reply Submission, p. 7)

5.3.8 F2016 Upgrades – Phase 2 GDAT

None of the transmission alternatives studied by BC Hydro, including the DCAT Project, provide N-1 service to new Gas Producer Loads beyond F2015 and require some additional upgrades for N-1 service to be available for all loads by F2016. BC Hydro states that the ultimate DCAT Project, including the F2016 Phase 2 GDAT project, is used as the basis of comparison for the considered alternatives. (Exhibit B-22, Attachment 2, p. 38) The exact configuration of the F2016 stage is not certain, although for the purposes of evaluation, BC Hydro assumes the GDAT project to consist of a new 73 km, 230kV transmission line from GMS to SNK, a new 30 km 230kV transmission line from SNK to SLS, expansion at GMS for an additional 230kV line position and replacement of

500kV/230kV transformers, and additional line positions at SNK and SLS. (Exhibit B-1, p. 3-7) BC Hydro emphasizes that the Phase 2 GDAT project is still in the study phase and not yet defined. (Exhibit B-22, Attachment 2, p. 7, pp. 73-74)

Even though the configuration of the F2016 phase of the GDAT project cannot be defined at this time, BC Hydro assigns system configurations for the F2016 phase of the transmission based alternatives as follows:

- Alternative 2: GDAT, same as F2016 phase for the DCAT Project (Exhibit B-22, Attachment 2, p. 38);
- Alternative B1: a new 230kV transmission line from GMS to SNK to the tap on 2L312 near the LAP substation, and either continue to utilize a tap from one of the 230kV transmission lines to supply the LAP substation, or construct a new 230kV switching station at the location of the tap on 2L312; also expansion at GMS for an additional 230kV line position and replacement of 500kV/230kV transformers, and additional line positions at SNK and the new Groundbirch substation (Exhibit B-22, Attachment 2, p. 40);
- Alternative B2: a new 230kV transmission line from GMS to WDM to SLS; also expansion at GMS for an additional 230kV line position and replacement of 500kV/230kV transformers, and additional line positions at WDM and the new SLS substation (Exhibit B-22, Attachment 2, p. 41);
- Alternatives B3, B4 and B5: a new 230kV transmission line from GMS to WDM; also expansion at GMS for an additional 230kV line position and replacement of 500kV/230kV transformers, and additional line positions at WDM (Exhibit B-22, Attachment 2, pp. 43, 45 and 47).

Commission Determination

Given the evidence available, the Commission Panel finds that Project Alternative 1, as proposed by BC Hydro, while not the least expensive option, is the most cost-effective transmission reinforcement alternative, as it provides significant flexibility to meet future anticipated growth, considering the available options. Nonetheless, the Panel finds considering a phased project such as DCAT and GDAT most challenging from the regulatory perspective, especially in the absence of an approved IRP.

The Panel observes this project has been approached on a phased basis, without sufficient evidence as to how the DCAT Project fits into long term planning. Without this evidence, the Panel is inclined to consider the DCAT Project as being flexible, and able to meet various potential longer term objectives. The future uncertainty is evident in the fact that, even if approved, the DCAT Project will be closely followed by a second phase to reinforce the service provided by the DCAT Project. Furthermore, the second phase, the need for which will be dependent on the load forecast, is still not defined. On the positive side, the phased approach allows for a gradual build-out of the system as load materializes, and could reduce the probability of stranded investment or overbuilding. Nevertheless, shortcomings of the phased approach have made themselves apparent.

Specifically turning to the alternatives introduced by BC Hydro in Exhibit B-22, the Commission Panel notes an inconsistent approach to the evaluation, conflicting statements regarding certain alternatives, consideration of non-feasible solutions, and the absence of consideration of other solutions. The Panel attributes these inconsistencies to the phased approach to this project.

When evaluating alternatives G1 and G2, BC Hydro has assigned significantly higher capital costs to these scenarios than it does to constructing what should be identical generation capacity in the Kelley-Nicola region. The Panel questions the basis for this comparison. Further, the Panel agrees with the BCPSO that in all likelihood, if BC Hydro needs extra generation capacity to supply load to the DCAT customers, it would not be sourced from natural gas. A better understanding could have been gained of the generation alternatives, if BC Hydro had also provided a comparison to scenarios where additional generation required for Alternative 1 comes from upgrading existing facilities – such as John Hart, for example – or purchasing additional energy on the open market. In addition, the analysis should include the full cost of the options being compared, which means not just the capital costs, but all the costs of generation.

The Panel recommends that if natural gas fired generation alternatives are to be considered for GDAT, they are to be compared on a consistent and transparent basis. Regardless of the economics of these alternatives, there is significant uncertainty regarding when and where to use natural gas fired generation. The Commission Panel considers that the proposed phased approach provides BC Hydro with sufficient flexibility for the growth in the area as well as CEA compliance.

With regard to Alternative B1, the Commission Panel notes that BC Hydro states it dismissed Alternative B1 in the planning phase, but this alternative is not listed as one of the dismissed options in the Appendix B of the System Planning Report in the Application.

The introduction of Alternative B2 does not seem to fit in the overall scheme of presenting alternatives to the proposed project because it is identical to the DCAT Project before this Panel. Any differences will only arise in the F2016 phase, which may be the subject of a separate application. Similarly BC Hydro also introduces Alternative B3, apparently in response to suggestions in IRs, but then declares the alternative to be not feasible and provided no further comparative analysis. The usefulness of advancing both these alternatives is questionable. The Panel would have found it far more helpful if the alternatives were feasible alternatives to Dawson Creek and Groundbirch area load growth for the first phase of construction. For instance, it is not apparent why BC Hydro has not considered different configurations, such as a single 230kV transmission line from LAP to BMT or DAW and then to TAY.

Such different configurations present different options for the F2016 phase, and possibly for the future transmission system configuration in that area and could minimize or even eliminate the 230 kV expansion at BMT, and significantly address local landowner concerns and past BC Hydro commitments and replace these with a 230 kV expansion at DAW and TAY. The long term planning progression would be more readily apparent than the phased approach inherent in the DCAT Project.

A significant feature of all the “B” transmission alternatives that does not appear to be a part of the DCAT Project, or Alternative A1, is the Groundbirch substation, sometimes in addition to, and sometimes instead of the SLS substation. BC Hydro’s own evidence states that at the time of the Application, it had insufficient knowledge of the location and configuration of customer loads to adequately identify the requirements for a substation in the Groundbirch area. The evidence also shows potential cost savings and equipment reduction by consolidating the SLS and Groundbirch substation at a single location. The Panel expects BC Hydro to adopt the most cost-effective approach.

Regarding the valuation of losses, the Panel agrees with the CEC that the Government's recent LNG policy of allowing natural gas generation for the LNG facilities to be categorized as clean energy creates the condition to allow BC Hydro's load resource balance to be in energy surplus at least until F2022. With respect to BC Hydro's treatment of transmission losses, the Commission Panel notes that the selection of the preferred alternative is very sensitive to the value of losses as described below.

In the Application, it is shown that although the PV of the capital cost of Alternative 1 is $51 million greater than that of Alternative 2, the Project Total PV (which includes Capital, O&M, Tax and System Losses) of Alternative 1 is $12 million less than that for Alternative 2. In this swing of $63 million in the comparative PV of the two alternatives, system losses account for a $69 million increase in the PV of Alternative 2. The sensitivity to loss valuation is then evident by BC Hydro's own evaluation that the PV cost of both options becomes roughly equal if the BC Hydro system is in energy surplus until F2017, suggesting that the value of the incremental losses associated with Alternative 2 has decreased by $12 million, from $69 million to $57 million. Furthermore, the PV cost of Alternative 2 is approximately $10 million less than that of the DCAT Project if the BC Hydro system is in energy surplus until F2022.

However, identifying F2017 as the year in which the energy surplus is exhausted may be pessimistic, as that assumption is based on both the Douglas Channel LNG facility and the Kitimat LNG facility coming on-line in F2017. If the Kitimat LNG facility is delayed or the LNG projects are self-supplied, the energy surplus could exist until F2022. The Commission Panel is concerned that BC Hydro did not provide a quantitative evaluation for the continued preference for the DCAT Project in the face of losses valuation being driven by surplus condition of the system energy load resource balance beyond F2017, and that the DCAT Project may no longer be the lowest PV cost alternative in that situation.

6.0 PROJECT COSTING, SCHEDULE AND RISK MANAGEMENT

This section reviews the project cost estimates, schedule and various risk management aspects to determine whether BC Hydro has sufficiently addressed these issues.

6.1 Project Costs

BC Hydro provides a summary of the Project cost estimate, showing both the P50 Cost Estimate and P90 Cost Estimate based on an in-service date of April 30, 2014 as shown below:

Table 6.1 Project Cost Schedule

	PROJECT COMPONENT - DCAT CONSTRUCTION	**AMOUNT ($ million)**
1	Direct Definition Phase Costs	6.6
2	Direct Construction and Materials Cost	127.6
3	Project Management, Engineering, Property, Consultation, Environment	34.1
4	Sub-total: Direct Costs Before Contingency	168.3
5	Project Contingency on P50 Cost Estimate	28.6
6	Inflation (Note 1)	7.2
7	Sub-total: Direct Costs	203.0
8	Capital Overhead (Note 2)	7.6
9	IDC (Note 3)	9.5
10	Dismantling Costs (Note 4)	2.2
11	Total P50 Cost Estimate	222.3
12	Incremental Project Contingency (Project Reserve)	32.4
13	Incremental Capital Overhead due to Project Reserve	1.2
14	Incremental IDC due to Project Reserve	1.34
15	Incremental Dismantling Contingency (Reserve) (Note 4)	0.2
16	P90 Cost Estimate	257.4

Source: Exhibit B-1-3, p. 4-24

The CEC submits that the Commission can accept the costs and schedule for the DCAT Project as proposed by BC Hydro. (CEC Final Submission, p. 22)

The CEA submits it agrees that BC Hydro has chosen the alternative with the most reasonable cost that can still accomplish the upgrading of the area service in a reasonable staged manner, in keeping with the anticipated growth of the load in the area. (CEA Final Submission, p. 3)

6.2 Project Schedule

BC Hydro states the planned in-service date for the Project is April 30, 2014. The preliminary major project milestones are set out below:

Table 6.2 Project Major Milestones

	Milestone	**Date**
1	Anticipated Approval by the BCUC	September 2012
2	Engineering Detailed Design (start)	July 2011
3	Route Staking and Clearing (earliest start)	November 2012
4	Construction start	December 2012
5	In service	April 2014

Source: Exhibit B-1-3, p. 4-25

AMPC submits that the project should be delayed to allow for a comprehensive tariff review. AMPC further states it is a delay that customers have contingency plans for. “They will incur extra costs if the Commission does not provide the decision they expect, or does not provide it in the timeline expected.” Finally, APMC submits there is no entitlement to outcomes or timelines, only to fair and reasonable process. “Given the larger, potentially unnecessary, costs facing ratepayers, they deserve the full benefit of the Commission’s process.” (AMPC Final Submission, p. 21)

WMFN submits that the CPCN should be delayed in order to provide time for more meaningful consultation and impact assessment. (WMFN Final Submission, p. 65)

The City of Dawson Creek submits that the evidence on record overwhelmingly supports a conclusion that the DCAT Project is necessary, and in the public interest, and that the DCAT Project should proceed without further delay. (City of Dawson Creek Final Submission, p. 8)

6.3 Permits and Approvals

BC Hydro states it will ensure that all required permits and approvals required prior to completion of the 230 kV transmission lines, SLS and expansion of BMT and DAW substations are secured, and that all work meets regulatory, statutory and safety standards. (Exhibit B-1, p. 4-26)

6.4 Risk Management

BC Hydro states it has identified and assessed risks that may be relevant to the assessment of the public convenience and necessity, and developed mitigation plans for managing those risks. Risk identification and mitigation is an ongoing process and the Project team will continue to identify risks and mitigation measures throughout the Project Definition phase and, if approved, the Implementation phase. It is expected that the risks and mitigation strategies will change as the Project moves through its phases. For this reason, risk identification, mitigation, and regular progress monitoring are established processes that are being closely followed. (Exhibit B-1, p. 7-1)

BC Hydro submits the primary uncertainties associated with the assessment that the Project is in the public convenience and necessity arise in the following areas:

- Need for the Project;
- Cost of the Project;
- Adequacy of the Project;
- Timeliness of Project Completion;
- Safety of the Project; and
- Environmental Impacts of the Project. (Exhibit B-1, p. 7-1)

The need for the Project has already been reviewed in Section 3.0, including the load forecast risk and the urgency of the system upgrade. The environmental impacts will be considered in Section 7.5. The Panel determinations throughout this Decision will have some impact on BC Hydro's project schedule. This section will further focus on the cost risks of the Project, load related risks and adequacy and safety of service.

6.4.1 Cost Risk of the Project

BC Hydro states the security arrangements it has adapted for this project provide that the risk of 60 percent 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 percent 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. (Exhibit B-1, p. 7-2)

6.4.1.1 Procurement and Resource Availability Risks

BC Hydro states that examples of procurement and resource risks include:

- Availability of contractor resources including local accommodation due to extensive industrial and construction activities in the area;
- Higher than expected bid prices due to uncertainty in steel pole prices and/or potential for high demand of labour.

BC Hydro states the cost estimate prepared for the Project incorporates knowledge gained from work implemented on other BC Hydro transmission projects and includes appropriate contingencies to accommodate the known and unknown cost risks of the Project. However, there is always uncertainty in future pricing, whether it is due to currency fluctuations or increasing demand for steel. The large number of upcoming transmission line projects in BC, as well as North America, could also affect the availability of skilled labour required to construct the Project. (Exhibit B-1, p. 7-3)

To reduce the risk that cost estimates would be incorrect, the contingency used in the cost estimate was developed using range estimating techniques (Monte Carlo simulation) that take into consideration the differing levels of uncertainty in the various scope items in the estimates. Estimate scope items are given ranges including the lower cost, the higher cost and the most likely cost. These ranges are converted to probability curves for the scope items and subject to simulation algorithms that ultimately generate an overall probability curve for the Project estimates. From this curve, values are taken that are used to produce the P50 Cost Estimate and the P90 Cost Estimate. (Exhibit B-1, p. 7-3)

In addition to managing the contingency through use of Monte Carlo simulations, the estimate of BC Hydro's engineering consultant, SNC-Lavalin's was independently reviewed by BC Hydro Transmission Engineering. BC Hydro found the estimate to be within the accuracy level of the cost estimate, and that the contingency analysis was performed in an appropriate manner, similar to what BC Hydro would perform for a project of this size and scope. (Exhibit B-1, p. 7-3)

BC Hydro explains that the preferred procurement strategy for this project is design-bid-build (DBB), thus providing BC Hydro with the ability to address the schedule risk more effectively. DBB can reduce the overall project timeline because it could permit procurement and construction to proceed on portions of the Project where design has been completed, while design on other remaining portions is ongoing. Additional benefits of the DBB option would be the ability to use BC Hydro's blanket order pricing for most of the major equipment requirement. As well, BC Hydro would more effectively manage Aboriginal engagement by leveraging direct award opportunities. (Exhibit B-1, p. 7-4)

6.4.1.2 Construction and Design Related Risks

BC Hydro states there are many construction and design related risks such as: scheduling system outages; discovery of bird nests while clearing; inability to use the Ministry of Transportation (MoT) ROW due to policy issues; discovery of geotechnical conditions during engineering; adverse weather; or triggering of an environmental assessment under the *Canadian Environmental*

Assessment Act. (Exhibit B-1, p. 7-4)

BC Hydro explains that many of the issues identified are inherent to the nature of a linear corridor project. Conditions will vary along the entire length of the corridor and issues may be detected any time during the detailed design and construction, however some general measures related to the development of the Project schedule and cost estimate can also mitigate the potential effects. (Exhibit B-1, p. 7-4)

BC Hydro further states that managing the schedule can also mitigate the impacts of these risks on the costs of the Project by reducing the need for change orders such as: Project critical path identification; due diligence concerning contractors such as: a review of historic performance; resourcing; financing; and flexibility to shift work activities and plans to recover lost schedule. (Exhibit B-1, p. 7-5)

The CEC submits that the risk summary and BC Hydro's proposed management and control as well as assessment of impact and probability is reasonable for the issues summarized in the table. The CEC submits the Commission can rely on the BC Hydro risk management with regard to its approval of the DCAT Project. (CEC Final Submission, p. 22)

6.4.2 Load Related Risks

BC Hydro states that to ensure its existing customers are not exposed to undue load related risk it has asked the industrial customers that are seeking more than 10 MW of power to provide security for their pro rata share for the costs of the Project. The sum of the pro rata shares of each of the five large customers will be equal to 60 percent of the cost of the Project. (Exhibit B-1, p. 2-19)

BC Hydro confirmed that currently five industrial customers are seeking 10 MW or more power. Their aggregate load is reflected in Base Case Gas Producers Forecast as 92 MW and 147 MW in F2012 and F2027 respectively which is 60 percent and 53 percent of the total forecast in those years. (Exhibit B-5, BCUC 1.38.2.1) BC Hydro has filed confidentially five letters of support that were signed by parties over the August-September 2011 period. These letters of support address both the security for system reinforcement required to supply electricity and commercial arrangements for pre-ordering equipment. (Exhibit B-5, BCUC 1.38.2.3)

In accordance with the signed letters, BC Hydro will work with each customer to determine or confirm the final amount of security and a mutually acceptable form of security in reflection of prior discussions. In the normal course of events, BC Hydro would not be ordering equipment of the type required for the DCAT Project until it has received a CPCN. In this case, however, BC Hydro is prepared to pre-order equipment to meet customers' in-service dates providing the customers agree to provide additional security. These arrangements were also addressed in the signed letters.

On July 4, 2012, BC Hydro filed a Securities Arrangements Update with the Commission. (Exhibit B-31) Highlights of that update were as follows:

<u>Shell Canada Ltd.</u>

Shell has executed a facilities agreement with BC Hydro in the form required by TS 6 in connection with its full anticipated requirements of 120 MW. A redacted copy of the unsigned agreement and an Escrow Agreement executed between BC Hydro, Shell Canada Ltd. and Davis & Co. LLP were included as Attachments 1 and 2 respectively. The estimated dollar commitments are shown below:

- The estimated cost for the *Basic Transmission Extension* is $12.7 million plus 12 percent HST. Shell is required to provide cash contribution for this cost.
- The estimated cost for the *System Reinforcement* is $99.9 million. Shell is required to provide security for this cost. This System Reinforcement cost is composed of an Interconnection System Reinforcement of $11.5 million and Shell share of the anticipated DCAT Project cost allocated to new customers ($131.5 million) of $88.4 million.

The final amount owed to BC Hydro will be based on actual costs using BC Hydro's standard charge out rates for external customers less any pre-payments made by the customer.

Murphy Oil Company

Murphy has entered into a letter agreement with BC Hydro pursuant to which it agreed to provide security in connection with 20.6 MW load to be served by the DCAT Project. An executed copy of that Security Agreement was enclosed as Attachment 3 to Exhibit B-31.

Encana Corporation

BC Hydro states it has presented Encana with the final form of a letter agreement pursuant to which Encana will agree to provide security in connection with 13.9 MW of load to be served by the DCAT Project.

ARC Resources Ltd.

BC Hydro states it is finalizing the details with ARC Resources Ltd. to enter into a letter agreement pursuant to which it will agree to provide security in connection with 10 MW of load to be served by the DCAT Project.

Air Liquide Canada

BC Hydro states that its discussions with Air Liquide, which is anticipating an approval for its Phase 2 project (7 MW), continue. Air Liquide is expected to enter into a security agreement with BC Hydro, pursuant to which it will provide security in connection with 14 MW of load to be served by the DCAT Project.

In summary, BC Hydro states the aggregate security it expects to obtain is $131.5 million in connection with the DCAT Project. BC Hydro further states that this security will be available to offset the costs of the DCAT Project whether or not the shale gas projects giving rise to the anticipated new load ultimately proceed or not.

On July 20, 2012, BC Hydro confirmed that security arrangements have been entered into with EnCana Power and Processing ULC (EnCana) and ARC Resources General Partnership. BC Hydro states these agreements now increase the amount of binding commitments obtained to $121.2 M or approximately 92 percent of the DCAT costs allocated to the new customers. (Exhibit B-45)

6.4.3 Adequacy of the Project and Safety of Service

BC Hydro states there is a risk that the Project is not adequate to meet accelerating load growth as identified in section 3.6. 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. BC Hydro asserts that no other configuration of the Project has been identified that would provide better protection against this risk. (Exhibit B-1, pp. 7-5 to 7-6)

The following three factors contribute to potential safety risks of the DCAT Project, in addition to those typically encountered on any transmission construction project:

- The existing 138 kV transmission lines must remain in service during construction;
- Portions of the line run parallel to, and cross, Highway 97; and
- The use of helicopters for some portions of the work will be required. (Exhibit B-1, p. 7-6)

BC Hydro has addressed its worker safety and public safety mitigation in the Risk management Summary shown in Table 7-1. (Exhibit B-1, p. 7-11) BC Hydro submits it has committed to ensuring that all work on the DCAT Project meets safety standards and notes that no-one has contended this matter. (BC Hydro Final Submission, p. 12)

6.4.4 Interveners Submissions on Risk

CEC submits that on balance of the evidence it believes that the load forecast provided supports the case for the need for an energy supply project and by implication the DCAT Project subject to satisfaction of other criteria. The CEC notes that the natural gas price risk in the load forecast is a critical area for the Commission to be concerned with and the Commission may want to look at conditions which may mitigate some of these risks. The CEC further submits the level of disadvantage to the customers providing security for the transmission system is miniscule based on the known reliability of the BC Hydro transmission lines, over 99.9 percent. The consequence is that the customer risk reward balance is skewed toward the gas producers. The Commission may want to closely examine this concern along with other fairness concerns. (CEC Final Submission, pp. 9-10 to 9-11)

BCPSO submits that notwithstanding the uncertainties associated with BC Hydro's forecasts that are meant to justify this project, the $131.5 M in security that BC Hydro has secured does not sufficiently cover what is at risk for existing ratepayers. BCPSO further submits that overall BC Hydro's case for the DCAT Project hinges on loads evolving as anticipated in BC Hydro's Base Load Forecast and very little variation is required before ratepayers face the cost stranded assists. BCPSO suggests that an examination of the merits of this Application requires the Commission to determine whether that Load Forecast is reasonable given the significant risks errors pose to ratepayers and a careful, meticulous consideration of the trade-offs between costs, reliability, and the potential that this might be a circumstance where BC Hydro's limited ability to use gas-fired generation is best employed. (BCPSO Final Submission, pp. 4, 12-13)

Commission Determination

The Commission Panel recognizes project cost risks inherent in schedule delays, and the government's objective under SD No. 9 to support economic development in the province expeditiously. However, the Panel has already found that the DCAT Project, while needed, must not necessarily be in service by April 30, 2014. Furthermore, determination in Section 9.0, respecting First Nations Consultation will also impact the project schedule to some degree.

In summary, the Panel acknowledges the various risks for the Project, as identified by the Parties. These risks relate primarily to timing, cost increases due to potential delays, and the load forecasts. However, the Panel is satisfied that these risks can be mitigated or managed as outlined by BC Hydro. This finding is subject to further discussion in Sections 7.0, 8.0, and 9.0.

7.0 CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY CONSIDERATIONS

In this section the Panel will consider the nature of "public" and what constitutes public interest issues. These issues include adequacy of the consultation process, obligation to serve, whether the Project is aligned with the *CEA* and other government policy, environmental issues and systemic impact.

7.1 Who is the Public and What are the Public Interest Issues

The Panel is guided by section 46 of the *UCA*, which provides that the Panel must consider those who receive or may receive service from BC Hydro, the *CEA* and BC's energy objectives. Public interest issues are often competing, and the Panel is compelled to consider a variety of rivalling public interests that include:

- the need for the project in the community to be served;
- the cost of a project and the impact on rates;
- whether a project is viable in the long term, or whether it will become a stranded asset, which may impact ratepayers;
- geographic discrimination in the level of electrical service to customers throughout the province;
- the safety and reliability of the current service and the proposed project;
- the environmental impact of the construction and operation of the Project;
- the impact of the project on neighbouring properties; and
- the impact of the project on First Nations communities, and whether the Applicant has adequately identified, consulted and, if necessary, accommodated any impacted First Nations Community.

The Supreme Court of Canada is clear, that there is no recipe for the determination of what 'public convenience and necessity' means. Each situation must be determined by the Commission, and cannot be determined without a substantial amount of administrative discretion, based on the particular facts of the application and in context of the regulatory framework (*Union Gas Co. of Canada Ltd. v. Sydenham Gas & Petroleum Co.* [1957] S.C.R. 185 (S.C.C.). Whether an application meets the test of the public convenience and necessity is not a simple objective fact, but is a matter of opinion.

BC Hydro sets out who it considers to be stakeholders with an interest in this application. (Exhibit B-1, p. 6-26) These stakeholders include:

1. Neighbouring property owners;
2. MLA's for the project area, and their staff;
3. Peace River Regional District and their board of directors (PRRD);
4. Senior staff and elected officials for the City of Dawson Creek, Town of Pouce Coupe and the City of Chetwynd;
5. Montney gas producers active in the Project area;
6. Metis;
7. Crown land tenure holder (trappers, grazers, etc.);
8. Local environmental and community non-profit non-governmental organizations (NGO')s;
9. Members of the general public in the Project area; and
10. Local and regional media.

In addition, BC Hydro has identified a number of First Nation's stakeholders, dealt with in Section 9.0.

Commission Determination

The Commission Panel acknowledges that given the requirements of the *UCA* and relevant jurisprudence, the finding of a project to be in the public interest is an evidence based process.

With respect to identification of stakeholders, and the 'public', the Panel finds that BC Hydro has been reasonable. With respect to the public interest issues, further questions that arise. Is the Project that is chosen for the application the best alternative? Will it meet the anticipated needs for the business and residential community in the Dawson Creek area? What are the anticipated needs for the business and residential community, and is that need consistent over the long term? Does it meet BC's Clean Energy objectives? Who is the public? Have the relevant stakeholders been identified and consulted? The *public interest* is always a matter of interpretation, and considers the customers who are supported by the project, the community, and the stakeholders who are impacted by the project. This framework sets limitations on the scope of the review of the Application. Although this Application was initially complicated by the controversy surrounding the nature of the business of the new customers who are the driving force behind the need for the DCAT Project, the Panel must make its decision about whether the Project is in the public interest within the context of the Project itself, and not within the context of the business of the new customers.

7.2 Adequacy of Public Consultation

This section addresses the adequacy of the Applicant's efforts to consult the public. For public consultation to be adequate, the Panel considers that an active two-way approach is appropriate. The intent of the consultation process, as informed by the CPCN application guidelines is to identify the public who may be impacted by the Project, inform those stakeholders with a description of the project, and feasible project alternatives, and identify project risks to those stakeholders. Respecting the two-way process, an Applicant must not only inform, but must also provide meaningful opportunity for input and feedback from stakeholders.

The Applicant is expected to identify potential risks and measures that the Applicant has taken to mitigate those Project risks. Additionally, the Applicant is also expected to address other issues and concerns identified by stakeholders, during the consultation process, whether by describing measures taken to alleviate the issue, or by providing explanation as to why no further action is required.

In reviewing the relevant evidence for proof of adequacy of public consultation, this Panel will consider both the quantity and quality of consultation efforts. It is apparent, by the sheer numbers and diversity of the list of Interveners registered in this Application, the community affected by the potential Project is aware of DCAT. Interveners include municipal government, private land owners, industrial and commercial users, First Nations, and a variety of NGO's, including BCPSO, and BCSEA.

BC Hydro lists the many activities it has conducted to consult stakeholders respecting the Project. It's public engagement activities included: letters and notifications; presentations and meetings; Project website; Project update information sheets; newspaper and radio advertisements; public open houses; and published media interviews with BC Hydro regarding the Project. This engagement process was used to introduce the Project and to obtain feedback for the reference route and substation locations. (Exhibit B-1, pp. 6-27 to 6-28)

BC Hydro identified potential impacted home owners as key stakeholders. (Exhibit B-1, p. 6-29) The Robinsons, home owners who are self-identified as impacted key stakeholders, registered as Interveners. The Robinsons own land adjacent to the BMT proposed site 1. Approval and development of site 1 would result in the Applicant needing some of the Robinsons' property, in order to facilitate the development. The Robinsons suggest that proposed Site 2 option would also impact their land. The Robinsons have two issues with this Project: first, whether the proposed BMT expansion is necessary at all, and second, whether it could be constructed on a different site. (Exhibit C11-1; Exhibit C11-6, p. 1)

Although BC Hydro has not specifically addressed the Robinsons' evidence directly, Table 6-6 in the Application lists a summary of issues identified through the public engagement process. Item 1 identified the concern that the Project is not needed, and addressed that concern. Item 2 addressed the concern that the Hydro line should be on the highway road allowance not on private property. BC Hydro noted the need to balance a number of competing issues, including environmental and First Nations impacts in determining the route. Under the heading of Environment, property owners identified the issue that the right of way would have a negative impact on wildlife in the area. The Applicant responded that no habitats critical to wildlife species at risk have been identified along the route. In response to pole placement, noise issues, and the visual impact, BC Hydro responded that it would work with owners on pole placement, that conductor design has been chosen to minimize line noise, and that efforts, such as potentially leaving a tree screen will be made to mitigate the visual impact. In terms of the impact of a new line to a property owner's health, BC Hydro states that it is guided by the opinions of such agencies as the World Health Organization, which opines that Electric and Magnetic Fields (EMF) levels created by power lines do not pose a health risk to humans or livestock. (Exhibit B-1, Table 6-6, pp. 6-41 to 6-46)

Commission Determination

The Commission Panel finds that BC Hydro has adequately consulted the public. While the Commission Panel acknowledges the Robinsons concerns, especially their concern that the Bear Mountain Terminal site plan has increased substantially, the Panel notes that it must consider all stakeholder interests, and balance sometimes competing interests. Although the specific evidence of BC Hydro respecting the Robinsons' consultation process was not entered into evidence, save and except BC Hydro's suggestion that the Robinsons were consulted, the Panel accepts BC Hydro's evidence of plans to mitigate impact on neighbouring properties. **The Panel directs BC Hydro to specifically follow through on its plan to build a berm and/or a hedge to provide a visual and noise barrier between the BMT site plan and the Robinsons' property.** The Panel accepts BC Hydro's evidence that this property is the best location for the expansion of BMT, and finds no evidence to support the Robinsons' contention that the Project should be expanded on another neighbour's property.

7.3 Obligation to Serve

This section deals with BC Hydro's obligation to serve, in the context of public interest. Does BC Hydro have an absolute obligation to serve all customers, or are there underlying conditions?

BC Hydro provides that all members of BC Hydro's rate classes, regardless of when they joined the rate class, are entitled to receive benefits of low cost heritage energy. (Exhibit B-22, p. 4) BC Hydro further suggests that new load ought not to be discriminated against, with respect to rate or service. "BC Hydro's rates, and the related terms and conditions of service, do not distinguish between customers based on the use to which power is put." (Exhibit B-22, p. 5) Such a distinction would be a significant deviation from its obligations, and would require extensive consultation with stakeholders. Further, BC Hydro states that its obligation to serve is an essential part of its mandate. Mr. Sanderson, BC Hydro's legal counsel, suggests that the obligation to serve is absolute; Mr. Sanderson went through the origins of the obligation to serve, tracing its origins to the Magna Carta, citing *Chastain v. BC Hydro ((1972), 32 DLR 3rd, at 443)*. In that case, BC Hydro attempted to collect security from customers who were poor credit risks. This case provided that a public utility cannot discriminate against customers. Mr. Sanderson states: "Hydro must serve all those who come to it ready, willing and able to meet the requirements that this Commission has said are necessary for customers to meet in order to be entitled to service." (T2:145)

BC Hydro states it has never declined service to any customer willing to assume its responsibilities under TS 6, explaining it does not have the discretion to refuse service to an eligible customer that requests it. (Exhibit B-22, Attachment 2, p. 78)

Shell submits that BC Hydro has an obligation to serve all customers, in accordance with TS 6, and that BCUC does not have the discretion to interpret TS 6 in a manner that would be discriminatory against Shell. In this regard, Shell submits that it has made considerable investment in the Dawson Creek area, relying on BC Hydro's obligation to serve. In addition to the wording in TS 6, Shell relies on section 39 of the *UCA*, which provides, upon reasonable notice BC Hydro must provide service, at reasonable rates, to all customers who are willing to pay the reasonable rate, so long as such customers are reasonably entitled to it. (Shell Final Submission, pp. 1, 7) The City of Dawson Creek also cites BC Hydro's obligation to serve as mandated by section 39 of the *UCA*. (The City of Dawson Creek, Final Submission, pp. 2-3)

BCSEA submits: "Second, BC Hydro's argument that the 'need' for DCAT is defined by the obligation to serve the new natural gas production load logically precludes consideration of the 'pros and cons' of the load to be served by DCAT." (BCSEA Final Submission, p. 3)

In considering the question of the obligation to serve, the CEA compares this Application to other applications that have appeared before the Commission, and submits:

> "Although the CEA's detailed positions on these and other matters are set out below, in brief the Application is no different than other relatively recent applications to the BCUC for the Vancouver Island Transmission Reinforcement/Sea Breeze VIC (VITR) the Interior Lower Mainland (ILM) or Central Vancouver Island (CVI) transmission projects. No one in these regulatory processes expressed any interest in migrating into the issues described above. Certainly parties in BCUC proceedings should not be shackled by precedent or from positions previously taken but the facts or valid reasons for change have to exist." (CEA Final Submission, p. 3)

In short, the CEA submits that the forest industry, as an example, is not required, under a denial of an obligation to serve, to provide its own energy for its production, and that the only reason this is even a question in this Application is because the natural gas industry has an ample supply of natural gas to provide its own energy needs.

CEC submits that it is disinclined to see BC Hydro's new customers be declined service, provided they are able to meet the prescribed requirements for qualifying to have the investments made to provide them service. (CEC Final Submission, p. 18)

BC Hydro submits the obligation to serve is weighed against the Commission's determination that the provision of service must be just and reasonable. (BC Hydro Final Submission, p. 3)

Commission Determination

The Commission Panel considers BC Hydro's obligation to serve as one part of the many considerations involved in a CPCN Application. The Panel further considers that the obligation to serve is subject to the Commission's judgment that such service is adequate, safe, efficient, fair and reasonable.

The Commission Panel recognizes BC Hydro's own interpretation of its obligation to serve all customers who come to it ready, willing and able to meet the requirements that the Commission deems necessary for customers to meet under TS 6. Clearly, if BC Hydro has new customers applying for new service, and it has capacity, then it would seem reasonable that BC Hydro should not discriminate. Further, the Commission Panel acknowledges BC Hydro's obligation to serve under section 39 of the *UCA*.

However, the Commission Panel wishes to emphasize that the absolute obligation to serve is always in context: the service must meet the appropriate electrical standards; options must be weighed diligently; and the service must be adequate, safe, efficient, fair and reasonable. (*UCA*, section 28) If the Project does not meet the necessary prerequisite conditions, that is, adequate, safe, efficient, fair and reasonable, then the obligation to serve is not absolute. The spirit and intent of the *UCA* support this notion, that the obligation to serve must be adequate, safe, efficient, fair and reasonable. Therefore, the Panel will not approve a CPCN application simply because a new customer requires service.

7.4 Alignment with Clean Energy Act and Provincial Government Policy

7.4.1 British Columbia's Energy Objectives

BC Hydro notes that the DCAT Project meets, in particular, three of the government's energy objectives that are set out in section 2 of the *CEA* and provides its reasoning as follows:

(i) Reduce B.C. greenhouse gas emissions pursuant to the legislated targets for 2012, 2016, 2010 and 2050 set out in the Greenhouse Gas Reduction Targets Act. (CEA, subsection 2(g))

BC Hydro states that upgrading the transmission system in the Peace Region will allow natural gas producers to connect to the BC Hydro electric system "providing clean energy to meet their compression requirements rather than the alternative of using natural gas driven compressors." Based on the forecast electrical load related to gas production, BC Hydro estimates the avoided/reduced GHG emissions to be in the range of 1 million tonnes per year in BC. (Exhibit B-1, p. 2-16) *(ii) Encourage the switching from one kind of energy source or use to another that decreases GHG emission in British Columbia. (CEA, subsection 2(h))*

BC Hydro states that in the absence of the proposed upgrades to the infrastructure, natural gas producers will procure gas driven compression to meet their compression requirements. Furthermore, natural gas producers have indicated to BC Hydro that once they commit to a particular technology at a site, "there is little to no likelihood of switching from that technology." Therefore, BC Hydro submits, it is critical for it to have sufficient capacity at the time of customer requests for electric service, because otherwise decisions will be made to use more GHG intensive gas compression. (Exhibit B-1, p. 2-16)

(iii) Encourage economic development and the creation and retention of jobs. (CEA, subsection 2(k))

BC Hydro states "the upgrading of transmission infrastructure in the Peace region will bring low cost electricity into the fastest growing industrial sector in B.C." and enable it to make a significant contribution in encouraging economic development. It is anticipated that with the production levels identified in the Dawson Creek Area Load Forecast, the industry will need to invest billions of dollars in the Montney basin. BC Hydro believes that by providing industry with a choice of natural gas or electricity, it will make a positive contribution to the overall economics of development in the Montney basin. BC Hydro acknowledges, however, that the choice between gas and electricity for compression will not be the primary determinant of the extent of development in the Montney. In this regard, BC Hydro states that at the margin 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." (Exhibit B-1, p. 2-17)

In addition, the following energy objective has received significant attention in this proceeding:

(iv) *Generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity. (CEA, subsection 2(c))*

BC Hydro raised this issue in the context of local gas-fired generation alternatives to the DCAT Project by outlining its views on the limits on gas-fired generation imposed by *CEA*. (Exhibit B-22, Attachment 2, pp. 59-60)

7.4.2 Other Considerations under s. 45(3.3) of the UCA

BC Hydro submits the other considerations referenced in subsections 46(3.3)(b) and 46(3.3)(c) of the *UCA* do not apply in this Application. First, BC Hydro has not yet filed its final IRP for approval by government, and "there is no applicable IRP by which the BCUC must be guided." Moreover, BC Hydro submits that the 2009 Long-Term Acquisition Plan is not an approved IRP. Second, BC Hydro submits that because the BC Government has not prescribed planning guidelines or clean or renewable resources targets in relation to s. 19, the criterion in subsection 46(3.3.)(c) is not applicable. (BC Hydro Final Submission, p. 4)

7.4.3 Special Direction No. 9

As outlined in the regulatory and policy framework introduction, section 2.1 of SD No. 9 directs that in deciding whether to issue BC Hydro a CPCN, the Commission must consider and be guided by the government's objective of encouraging public utilities to develop adequate transmission infrastructure in the time required to serve persons who receive or may receive service from the public utility.

BC Hydro first states that 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 even without SD No. 9. BC Hydro then emphasizes how "SD No. 9 underscores the importance of planning to ensure inadequate transmission capacity does not hamper economic development in the province." (Exhibit B-1, p. 2-18)

7.4.4 Submission by Parties

BC Hydro submits the DCAT Project supports the objectives set out at paragraphs 2(g), 2(h) and 2(k) of the *CEA* and does not detract from any of the other British Columbia's energy objectives.
BC Hydro further submits that although the Project will increase rates, it will not detract from the objective set out at paragraph 2(f) "to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America." This is because BC Hydro does not interpret the objective 2(f) to discourage BC Hydro from serving all new load demand even though all new loads increase average rates for the reason that the cost of new supply exceeds the average cost of supply in the system. In BC Hydro's submission, its core obligation to serve, in fact, trumps the impact on rates and therefore the DCAT Project does not detract from the competitive rates objective. (BC Hydro Final Submission, p. 4)

Regarding SD No. 9, BC Hydro further submits that in addition to considering the obligation to meet the MRS requirement, the Commission must also have regard to the timelines of BC Hydro's efforts to upgrade its system. (BC Hydro Final Submission, p. 5)

BCSEA submits the evidence is insufficient to make a clear determination that DCAT would or would not result in an overall decrease in GHG emissions either within BC or globally and makes some additional observations. First, BCSEA notes that BC Hydro's Final Submission de-emphasizes the claimed BC GHG emissions reductions benefits of DCAT in the Application. Second, "if self-supply is not to be considered an alternative to DCAT then the GHG consequences of DCAT cannot be compared meaningfully to the GHG emissions consequences of self-supply." Third, BCSEA submits that the claim of avoided/reduced GHG emissions in the range of 1 million tonnes per year in BC is not quantitatively supportable. (BCSEA Final Submission pp. 1-3)

CEC submits that it will be more economical for BC Hydro to meet the 93 percent clean energy objective through transmission options than through local natural gas fuelled options. The CEC further submits the evidence supports that the DCAT Project contributes to the BC energy objective of reducing greenhouse gases. (CEC Final Submission, pp. 13-15)

BC Hydro did not address these issues in its Reply.

Commission Determination

The Commission Panel finds that the DCAT Project aligns with the *CEA* and Provincial Government policy. In making this determination, the Panel accepts BC Hydro's submission that the Project supports the objectives set out at paragraphs 2(g), 2(h) and 2(k) of the *CEA* and does not detract from any of the other British Columbia's energy objectives.

The Panel agrees with BCSEA that the evidence is insufficient to allow a definite determination regarding the overall impact on the GHG emissions of the DCAT Project. Nevertheless, this issue is not a key reason for granting the CPCN as the project need has already been established on other grounds. The Panel only has to find here that the Project aligns with the *CEA* overall.

7.5 Environment and EMF

7.5.1 Environmental Assessment

BC Hydro states that the DCAT Project does not meet the threshold requirements that would trigger an automatic review under the *British Columbia Environmental Assessment Act* or the *Canadian Environmental Assessment Act* 1992. BC Hydro retained AMEC Earth and Environmental Limited to conduct an EOA of the Project to determine whether, taking into account mitigations, the Project would result in significant adverse effects to the environment.

The EOA examined route options in the east, central and western segments of the Project, including the preferred route. Information was collected on fish and aquatics, vegetation, human environment, and archaeological resources. AMEC found that the DCAT Project has the potential to adversely affect the environment, especially during construction. However, the EOA concludes that following the implementation of appropriate mitigations:

(i) The Project will have a low or negligible effect on almost all the Valued Ecosystem Components (VECs) and the Valued Social Components (VSCs); and

(ii) There is no measurable difference among the options under consideration for almost all VECs and VSCs.

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. In terms of specific reviews the EOA included:

- Fish and Aquatic Resources: groundwater, fish and fish habitat;
- Vegetation and Soils;
- Wildlife: amphibians and reptiles, birds, mammals, wetlands;
- Socio-Economic Effects: during construction and the operations phase;
- Land and Resource Use: land use planning, crown tenures, agriculture and private land use activities, trapping, hunting and recreational fishing, forestry; and
- Archaeological Resources.

BC Hydro states that upon approval of the Project, it will prepare a construction EMP which will detail the permitting requirements and best management practices to be implemented during construction. Furthermore, the contractor will be required to write site specific Environmental Protection Plans prior to the start of the construction. (Exhibit B 1, pp. 5-1 to 5-24)

7.5.2 Electric and Magnetic Fields

BC Hydro states it calculated the expected EMF for the 230 kV transmission line between the SLS and DAW Substations, based on normal operation during average representative load, and the load with one circuit out of service, calculated one meter above ground level. The expected magnetic field values in milliGauss (mG) were measured directly under the transmission line, as well as at the ROW boundaries. BC Hydro shows that the expected magnetic field is approximately 20.2 mG and 55.7 mG directly beneath the transmission line conductors for normal and contingency operation respectively. The magnitude of the magnetic fields is expected to further decrease to about .7 mG and 5.9 mG at 50 meter distance from the centreline. These readings are to be compared to the maximum limit of exposure to magnetic fields recommended by the International Commission on

Non-Ionizing Radiation Protection (ICNIRP) of 2,000 mG. (Exhibit B-1, pp. 5-25 to 5-28)

With regard to the electric fields, the ICNIRP guideline limit is 5 kV/m. BC Hydro expects the magnitude of electric field during normal operations to be just below 1.5 kV/m directly under the transmission line and to drop to less than 0.1 kV/m at a 50 m distance from the centerline. Even with one circuit out of service the electric field is still well below the ICNIRP limit at 2.5 kV/m at the centerline.

Commission Determination

The Commission Panel is satisfied that BC Hydro has performed its due diligence in terms of environmental impact, subject to the First Nations issues, and that the Project meets the ICNIRP Guidelines. The Panel also agrees with the CEC submission that the evidence with respect of the routing of the transmission line and various environmental impacts and the efforts BC Hydro has taken to study and manage the impacts appears to be developed to an appropriate utility standard.

Accordingly, the Commission Panel accepts the routing and environmental treatments BC Hydro has applied to developing the DCAT Project.

7.6 Systemic Impact

BC Hydro has stated that the DCAT Project will have a small footprint. However, some parties have suggested that the impact has the potential to be more systemic, including a spider web of electrical distribution lines to supply dispersed customer load, and raised questions concerning the location of electrical substations in relation to customer load. The Panel will now consider the siting of customer load and the issues arising from that.

WMFN submits that the "…proposed DCAT Project is not just about DCAT - in its very nature, it is a project that will support and lead to other developments in the region. That is its chief purpose. Indeed, BC Hydro is quick to point out the level of anticipated development in the area that DCAT will serve in terms of justifying the need for the Project to proceed, including shale gas development in the Montney basin." (WMFN Final Submission, p. 54) Chief Wilson, in the oral hearing, testified that: "...Shell is going to tie into it. All the other companies are going to tie into it. It's going to turn into this spider-web of stuff out there." (T3:497)

CSI submits that "… it is unaware of any evidence submitted by BC Hydro that shows any plans for transmission lines and any system substations to serve the other numerous industrial oil and gas customer's that have submitted applications in the area. It seems contradictory and short sighted for BC Hydro to claim that the need for DCAT is driven entirely by industrial customer load but not have any system substation to serve the generic industrial customer geographical loads." CSI also submits that the loads to which CSI is referring are those noted in the "bubbles" on the submitted drawings in Exhibit B-30, BCUC 4.4.8.1. CSI notes that the only substation in the DCAT proposal is right next to the Bear Mountain Wind Farm, which is many kilometers from the load centre of the majority of the proposed industrial load customers. CSI finally submits that for DCAT (and in the future GDAT) to be properly planned and designed to serve industrial load customers, system substations should be planned for efficient and effective interconnection and service.

CSI submits the process and practices previously in place at BC Hydro and the former British Columbia Transmission Corporation (BCTC) need to be changed to accommodate the services required for the Oil and Gas customers. The existing model in BC has worked for services such as mines and other single, isolated industrial customers. In particular, it cites the example of Louisiana Pacific, which was required to construct its own substation (designated LAP in some of the figures provided by BC Hydro). As a result, the proposed DCAT Project is unable to utilize this substation. (CSI Final Submission, pp. 6-7)

BC Hydro disagrees with CSI, stating that there is no evidence to support the allegation that new customers will need to construct long lines at their own expense to connect to the system. It submits that not all customers will be required to connect to the BMT substation and some customers may choose to interconnect along the line, where technically appropriate. It further submits that Shell is considering this option. Further, BC Hydro states that it will accommodate a broad variety of interconnection points. (BC Hydro Reply Submission, pp. 11-12)

With respect to the location of proposed electrical compression along the gathering lines, BC Hydro states that it … "has been advised that for the four gas producers, electric driven engines are more likely to be utilized for natural gas compression at the gas plants, which are more centralized and designed for greater throughput, than at the smaller compressor stations distributed throughout the field. The load requirement for a compressor is generally independent of the field position and will be designed on specific parameters such as suction pressure, discharge pressure, gas quality, and capacity. The size of gathering lines and sales lines are engineered to meet the process requirements of the compressor station." (Exhibit B-22, Attachment 2, p. 8)

Commission Determination

Although the systemic impact issue has been raised by WMFN, and will be addressed as part of the Commission Determination on First Nation Consultation, the Panel considers it to also be of broader public interest.

Gas drilling and extraction operations in the Dawson Creek area are distributed over a significant geographical area. BC Hydro states that electrical compression is more likely at a centralized location. However, this statement in itself acknowledges that there is at least a possibility that there will be some electrical compression at less centralized locations. Thus there exists the possible emergence of one or more "electrical networks", each run by a private entity. Accordingly, the Panel acknowledges the concerns of the WMFN, and agrees that there may be the potential of a "spider web". With regard to CSI's contention, that new customers will need long lines to supply the electricity to the site of their load, the Panel notes that while there is no evidence to support this statement, there is no evidence to refute this either.

There is a potential for this issue to be exacerbated by sub-optimal siting of substations and other interconnection points on the transmission system. While the Panel makes no determination on whether BC Hydro's approach is optimal or not, it notes that there is a lack of evidence on the location of the new industrial loads. Under normal circumstances, there would be an approved IRP to consider – in fact, the *UCA* provides that the Commission must consider an IRP, as a requirement for a CPCN proceeding. (s. 46(3.3) *UCA*) However, there is no such document before the Panel, nor is there any other evidence of the location of the planned loads.

It is generally accepted that within a utility service area a single provider can plan, build and maintain an electrical transmission and distribution infrastructure more efficiently than can multiple providers. This approach, apart from being the most economically efficient approach, can more effectively reduce environmental impact. In the Panel's view, this is a key benefit of utility regulation.

The approach generally taken in the BC Hydro service area is that BC Hydro plans the transmission and distribution system, with Commission oversight. There may be exceptions, where a different utility provides service in a small "pocket" – for example Bird's Eye Cove – or for a customer owned purpose-built line to serve a specific plant, such as the Louisiana Pacific case cited by CSI. However, the Panel considers a circumstance where, say, four or more industrial customers each build and own a network to serve its own geographically distributed loads to be substantially different. The Panel questions why BC Hydro doesn't plan and build the electrical network in the Peace region as it does in other areas. The Panel notes the City of Dawson Creek's statement in its Final Submission: "The residents of Dawson Creek (both present and prospective) have a right to electrical service which meets the standards enjoyed by other residents of the Province." To this, the Panel adds the question: Is the Dawson Creek area – including both the First Nation residents and the non-First Nation residents - not entitled to the same level of oversight and planning as is provided for any other area in BC Hydro's franchise territory?

The Panel also questions whether, if BC Hydro planned a network to serve known and expected loads, what the impact, if any, on the DCAT Project alternatives would be. Would the same substations be required? In the same locations? What would the impact on cost be? The Panel notes that BC Hydro has split this project into two phases, in order to provide flexibility to the planning process – and the Panel has approved Alternative 1 for Phase 1 for this reason. However, this flexibility comes at the cost of greater uncertainty as to the impacts of the overall project because this approach could further exacerbate the spider web potential.

There is no evidence before the Panel about the number or location of these loads, or how the new customers plan to provide electricity to them. Accordingly no determination about the systemic impact can be made at this time. **However**, **the Panel directs that as part of the GDAT Phase 2 application, BC Hydro provide more detailed information about the location of customer loads and the routing and ownership of all transmission and distribution lines that are expected to be built.**

8.0 RATES AND TARIFFS

This section addresses rate and tariff matters, including review of current rates applicable to new customers, rate impact of the DCAT Project on existing and new customers, applicability of the System Extension Guidelines, application of Tariff Supplement 6 to the Project, and the proposed revisions to the Electric Tariff.

8.1 Rates and Rate Impact

8.1.1 Review of Current Rates

Three of the five new industrial customers will receive service under Rate Schedule 1823, Transmission Service – Stepped Rate which currently includes a demand charge of $6.263 per kVA plus an energy charge of $0.03261 per kWh for customers without a customer baseline load (CBL) and $0.07360 per kWh up to and including 90 percent of the Customer's CBL and $0.07360 per kWh above 90 percent of the customers CBL for customers with a CBL. T&C for transmission service are contained in Tariff Supplements 5 and 6.

Two of the five new industrial customers have opted for distribution service under Rate Schedules 1600, 1601, 1610, 1611 - Large General Service (150 kW and over) which includes a basic charge a demand charge and an energy charge as outline in the table below. T&C for distribution service customers are contained in the Electric Tariff.

Large General Service – Rate Schedules 1600, 1601, 1610, 1611	
Basic Charge	$0.1925 per day
Demand Charge	$0.00 per kW for first 35 kW $4.69 per kW for next 115 kW $9.00 per kW for remaining kW
Energy Charge	Part 1: $0.0937 per kWh for first 14,800 kWh $0.0451 per kWh for remaining kWh up to baseline
	Part 2: $0.0942 per kWh for usage up to 20% above baseline $0.0942 per kWh for savings down to 20% below baseline (credit) Usage or savings beyond 20% of baseline are based on Part 1 prices

8.1.2 Rate Impact F2013 –F2035

The first year in which BC Hydro's revenue requirement is forecast to be affected by the Project is F2013. The total forecast costs to be recovered in rates for the period F2013 to F2035 are shown below.

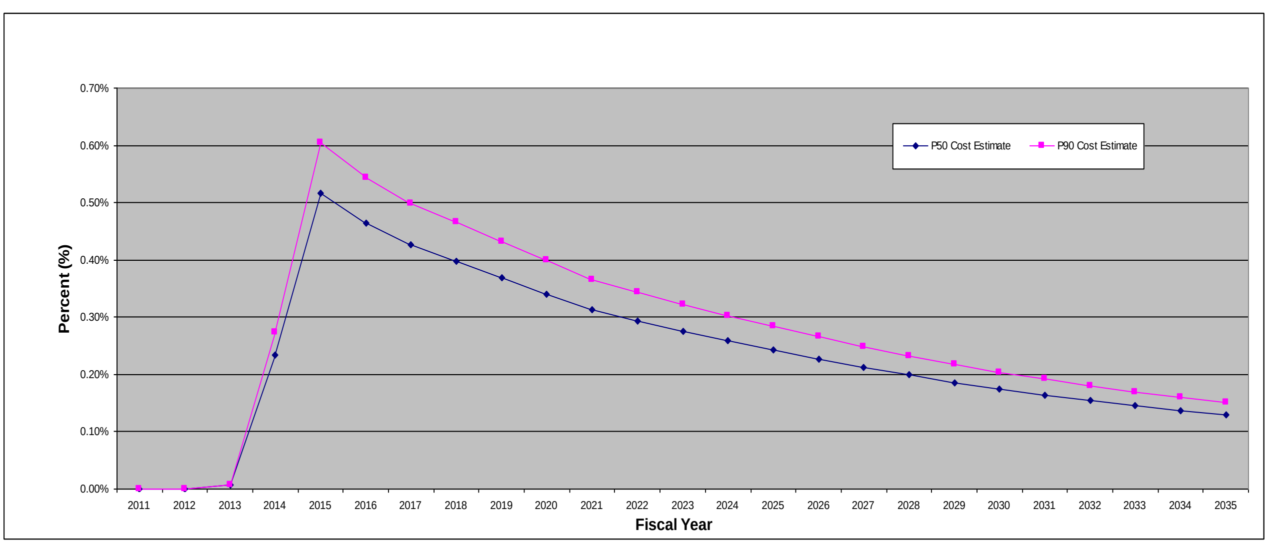
Table 7.1

Component	**P50** (in millions) F2013-F2035	**P90** (in millions) F2013-F2035
Amortization	$102.9	$120.6
Finance	$160.5	$188.5
ROE	$125.5	$147.3
O&M	$31.8	$35.7
TOTAL	$420.7	$492.1

Source: Exhibit B-1, Appendix I, Tab Summary

An initial increase in BC Hydro's revenue requirements is forecast in the early years as the Project goes into service as illustrated in the graph below. The revenue requirement increase would be highest (in dollar terms) in F2015, the first full year the Project is in service, at around $24.5 million for the P50 Cost Estimate (0.5 percent) and $28.7 million for the P90 Cost Estimate (0.6 percent). (Exhibit B-1-3, p. 4-26)

Figure 7-1 Rate Impact Comparison P50 and P90 Cost Estimate



Source: Exhibit B-1-3, p. 4-26

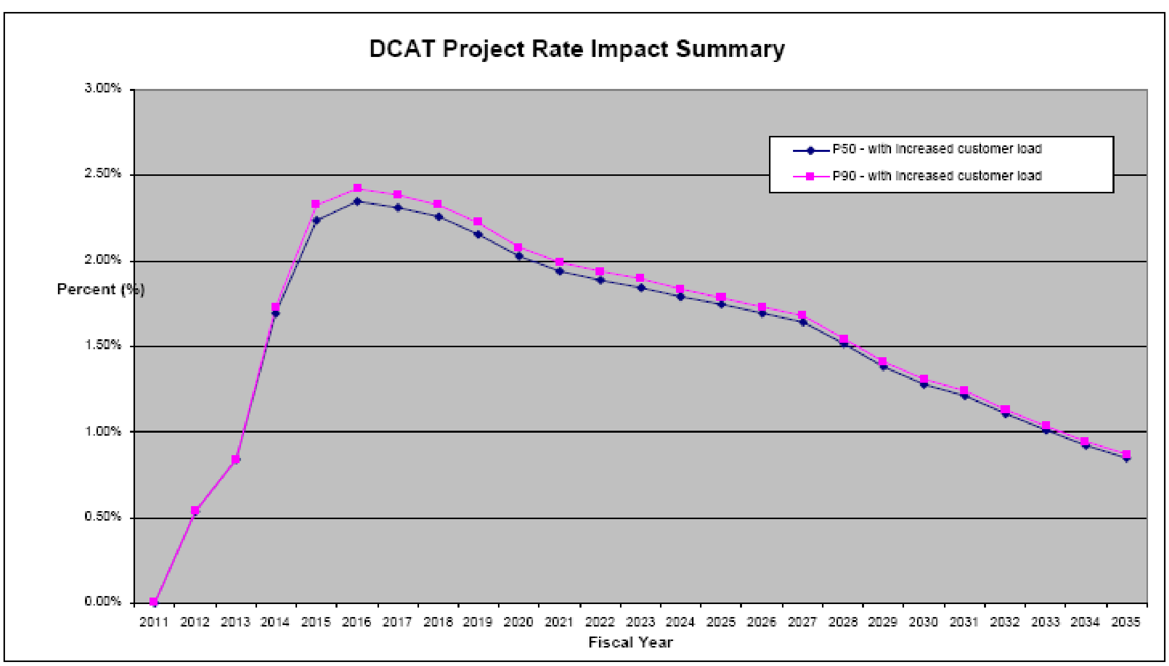
8.1.3 Rate Impact Including the Cost of Energy F2013-F2035

The BC Hydro rate impact model takes into account all incremental costs for the DCAT Project area reinforcement, including capital and operating costs associated with the facilities for which BC Hydro has sought a CPCN to serve existing and forecast customers and load in the DCAT area but it does not include the incremental cost to obtain the electrical energy required to service the new load. (Exhibit B-14, BCUC 2.25.3)

BC Hydro stated that the incremental value of energy required to supply the forecasted load would be $129/MWh, which is the weighted-average, levelized and adjusted firm energy price from the 2010 Clean Power Call. (Exhibit B-14, BCUC 2.25.1; Exhibit B-15-1, CEBC 2.2.4)

The figure below represents the P50 and P90 cost estimates including the incremental value of energy required to supply the forecasted load. As the figure illustrates, the peak rate impact when the cost of energy is taken into consideration, is in the region of 2.5 percent while the peak rate impact excluding the cost of energy is closer to 0.5 percent.

Figure 7-2



Source: Exhibit B-14, BCUC 2.25.3

On March 23, 2012, BC Hydro revised the incremental value of energy required to supply the forecasted load by reducing the costs to $50/MWh for the period up to F2017 as the system is forecast to be a surplus during that period as a result of SD 9. (Exhibit B-22, Q 67 & 68) The update indicated a peak rate impact in the range of 1.6 to 3.0 percent depending on the level of load forecast. (Exhibit B-29, BCUC 3.8.2)

8.1.4 Submissions by Parties

BCSEA submits that DCAT puts upward pressure on rates because it facilitates new load on the BC Hydro system. It further argues that the project as defined has an unacceptable impact on rates because TS 6 does not provide for a substantial contribution from new customers. In its view, the Commission should give consideration to the total rate impact, including the cost of energy to service the incremental customer loads. (BCSEA Final Submission, pp. 5, 13)

AMPC submits that rate pressure from the cost of incremental generation to supply the load, will be acute, although the rate impact of any specific project need not be considered at all. However, it also submits that it is crucial that the rate impacts of projects forecast over a reasonable planning horizon be considered when determining an appropriate contribution policy that will then be transparently and consistently applied to new customers. (AMPC Final Submission, pp. 6, 20)

CEA suggests that BC Hydro "would use all-inclusive rate impacts for portfolio analyses in an integrated resource plan but not necessarily for individual project evaluations." (CEA Final Submission, p. 8)

Air Liquide submits that there is nothing in the language of TS 6 to suggest that the cost of energy required to service new customer loads should be taken into account by the Commission. Further, the cost will be the same regardless of which project alternative is used. (Air Liquide Final Submission, p. 6)

BC Hydro submits that the cost of energy to serve incremental customer loads in the DCAT area is not relevant to the decision to approve the Application, because energy cost to serve load is generally common to all alternatives, and should therefore not be included in the analysis.
BC Hydro also submits that it procures its energy supplies on a consolidated basis, ensuring it has sufficient energy to meet the demands of all of its customers in the province. It states that since it does not purchase energy for a specific project, therefore specific energy should not be attributed to that project. (Exhibit B-14, BCUC 2.25.2)

Commission Determination

In the Panel's view, granting a CPCN should not be conditioned by a consideration of the impact on rates, of the cost of energy required to serve new load. Therefore the Panel will not consider any rate impact of the incremental cost of energy to supply the new load in the Dawson Creek area.

The Panel disagrees with BCSEA's argument that the project facilitates new load which will have an unacceptable impact on rates because TS 6 does not provide for a substantial contribution from new customers. Provincial policy entitles all BC Hydro customers, whether existing or new, to a share of heritage energy. Accordingly, as the base of customers grows, the share of heritage energy allocated to existing customers will be adjusted downward proportionately. Energy to meet consumption needs in excess of the amount of heritage energy available is obtained, typically at prices in excess of the price of heritage energy, through various means, including from IPPs and the spot market. Most BC Hydro customers receive energy on a tiered, or stepped, tariff. The principle has been established by previous panels when setting stepped rates, that the top tier rate should reflect the marginal cost of new supply. It is only through such principled pricing policies that support economically efficient consumption decisions, that fair allocations of the costs of energy to supply new customers can be achieved. The Panel notes that the Provincial Government has announced a "comprehensive industrial rate review" within the next two years. Accordingly all parties will have an opportunity to provide input to help ensure that rates remain fair and reasonable.

8.2 Applicability of the System Extension Guidelines

The Commission requested that parties address various issues about the applicability of the Utility System Extension Test Guidelines to the application of TS 6 in this hearing. (Exhibit A-31) The Panel will now consider those submissions.

Shell asserts that the BCUC is foreclosed as a matter of jurisdiction from applying the Extension Guidelines, to the extent that they are inconsistent with TS 6, by BC Regulation 158/2005 and BC Hydro's statutory obligation under s. 3(b)(iii) of *the Heritage Contract Act*. It further submits that, to the extent that the Guidelines are consistent with TS 6, the question of whether they should be applied should be considered as part of a larger rate review process. (Shell Final Submission, p. 9) Air Liquide agrees with Shell stating: "Air Liquide submits that the Guidelines should not be applied to TS 6. The Commission only has jurisdiction to apply the Guidelines insofar as they are consistent with TS 6. The Commission should properly make such a determination in the context of a larger rate review process in which all stakeholders can be heard." (Air Liquide Final Submission, p. 2)

CEA argues that the Guidelines should not apply to TS 6, because a system reinforcement is not a system extension. It maintains that DCAT is an: "…upgrade, expansion, reinforcement, or call it what you like, but not an extension to the BCH transmission system that requires the application of the Utility System extension test Guidelines." It further submits that: "Contributions in Aid of Construction" are not to be confused with any payments that may be required under TS 6. (CEA Final Submission, p. 5)

AMPC concurs, stating that the Guidelines are 16 years old, voluntary and focussed on small customers and, as such they have little relevance. (AMPC Final Submissions, p. 14) Similarly, ARC, Encana and Murphy assert that TS 6 has been in force for 20 years, and BC Hydro should not now be required to interpret it in any different manner than on the past. (ARC, Encana and Murphy Final Submission, p. 2)

However, the CEC is of the view that, as Guidelines, they may provide a useful reference for the nature of definition of issues and previous efforts to consider resolution of the issues, although TS 6 stands on its own. (CEC Final Submission, p. 24)

BCSEA submits that the Guidelines guide the Commission's public interest review of BC Hydro's proposed application of TS 6. It advances two ways in which the Commission intended the Guidelines to be applied: in deciding a utility's application for approval of a proposed system extension policy; or in the course of reviewing a system extension policy, for a particular system extension, within a CPCN. It is the latter case which is applicable here, and in this application of the Guidelines, the BCSEA considers the general principle that the costs of system extensions be allocated to those customers who cause them to be important. (BCSEA Final Submission, p. 8)

BCSPO submits that the Guidelines should apply to TS 6, and identifies several key areas where TS 6 doesn't reflect the guidelines, including using net revenues in the calculation of benefits; evaluation based on a DCF evaluation and the recovery of costs in the System Reinforcement costs as opposed to a connection fee. (BCSPO Final Submission, pp. 21-22)

In reply, BC Hydro submits that employing the Guidelines as an interpretive aid is flawed since they were issued after the TS 6 had been agreed on and filed as a tariff. Therefore, the Guidelines can't be a useful interpretive tool. (BC Hydro Reply Submission, p. 8) BC Hydro also disagrees with BCSEA's position, stating that it is obliged to apply the system extension policy embedded in its rate schedules. Accordingly, only the application of TS 6 can be considered. (BC Hydro Reply Submission, pp. 10-11)

Commission Determination

The Panel finds that the System Extension Guidelines should not be applied as is, but when not inconsistent with TS 6, and in areas where TS 6 is silent, they can be considered. In making this determination, the Panel considered the voluntary status of the Guidelines and the fact that TS 6 is a tariff approved by the Commission.

8.3 Application of TS 6 to the DCAT Project

8.3.1 Calculation of the Maximum Offset

Tariff Supplement 6 provides a formulaic approach to calculating costs and benefits of system extensions. When assessing benefits, it provides the Maximum Offset that BC Hydro will allow towards the cost of system reinforcement. The Maximum Offset is a measure of the benefits a transmission extension is expected to provide and is calculated as follows:

$$I = \frac{(R-E)}{.135} + B + D$$

The variables in the formulae above are defined in TS 6 as:

I=	BC Hydro's maximum offset towards the cost of System Reinforcement;
R=	the incremental revenue as calculated by BC Hydro from the estimated incremental load during the first year of normal operations;
E=	the estimated incremental operating and maintenance expense of supplying the incremental load during the first year of normal operations;
D=	one-half the annual depreciation associated with the estimated total costs of System Reinforcement; and
B=	other benefits to the BC Hydro system, as determined by BC Hydro.

BC Hydro states that, as applied to this project:

1. R is determined by estimating the revenue to be received from the customer in the first 12 months after it begins normal operations; and
2. E is determined by estimating operating costs associated with the specific portfolio of incremental facilities that BC Hydro must construct to serve the new load. That is, BC Hydro applies an annual operation and maintenance cost to the new facilities that have been identified as System Reinforcements, calculated as a percentage of the capital cost. (Exhibit B-22, p. 81)

Depending upon the value of the Maximum Offset, a new customer will either pay a refundable deposit, a Contribution in Aid of Construction (CIAC), or a combination of both. Section 5 states that the new customer will pay any amount by which the construction costs exceed the Maximum Offset and, in addition, provide a security deposit in the amount of the Maximum Offset.

As outlined previously, the DCAT Project is designed to serve existing load, two distribution voltage customers and three transmission voltage customers. Therefore, BC Hydro states that this required some decisions to be taken in interpreting TS 6. It began its assessment by determining that 60 percent of the estimated DCAT Project costs were properly assigned to the five new customers, and that this was a rounding from a calculated allocation of 64 percent. BC Hydro then determined that all five customers should be treated equally to one another regardless of their supply voltage. Accordingly, BC Hydro requests certain amendments to its Electric Tariff. (Exhibit B-22, p. 83)

In its supplemental evidence, BC Hydro summarizes the subsequent steps that it undertook to determine the cost and security responsibility of each customer as follows:

1. Determine System Reinforcement costs for each customer;
2. Apply the first step in the offset formula by comparing BC Hydro's net revenue from each customer in the first year of normal operations times 7.4 to the System Reinforcement cost; and
3. Determine the pro-rata security to be collected from each customer in light of its allocated System Reinforcement cost. (Exhibit B-22, p. 83)

BC Hydro stated that it has sought to discern and apply the plain meaning of the tariff in the absence of express language dealing with this situation. BC Hydro has not considered if this approach is appropriate for all cases that may be covered by the hypothetical circumstances of the question, but does believe that it is appropriate in this case. (Exhibit B-30, BCUC 4.8.1.1)

For the five new DCAT customers combined, BC Hydro calculates the Maximum Offset at $429 million, by applying the above formula with the following assumptions:

R = $58 million/year from five customers providing security with a combined load of 176 MW

E = $1 million

B = assumed to be zero

D = $2 million.

(Exhibit B-5, BCUC 1.48.2)

It is unclear exactly what rate assumptions were used to determine that R = $58 million, but it is unlikely that energy costs are included. Q111 in the Supplemental Evidence states: "R is determined by estimating the revenue to be received from the customer in the first 12 months after it begins normal operations." (Exhibit B 22, p. 81)

Based on the inclusion of approximately seven years revenue being applied to the system reinforcement costs for this Project, for the five customers providing security, BC Hydro's maximum offset as calculated in TS 6 is be $429 million, which exceeds the estimated cost for system reinforcement assigned to customers of $131.5 million. This results in a refundable security requirement from the five customers of $131.5 million and no required contribution. (Exhibit B 5, BCUC 1.40.1, 1.48.2)

8.3.2 Interpretation of TS 6

In its earlier scoping decision, the Panel determined that "… it is appropriate for parties to provide evidence and ask questions as to the application of TS 6 to the DCAT project so as to allow the Commission Panel to determine whether the DCAT project is in the public interest." (Exhibit A-28, Order G-56-12) The Panel will now consider these submissions.

BC Hydro utilizes TS 6 to determine the extent to which the new customer or load is responsible for the cost of additions or alterations by assigning cost responsibility between BC Hydro and individual customers for System Reinforcements. (Exhibit B-22, p. 76) BC Hydro submits that in this project, the cost of reinforcing the system will be substantially recovered from new customers to the benefit of existing customers. It maintains this is because existing customers will only be allocated less than half of the project cost, stating that "…between 92 and 100% of the remaining 60% of the reinforcement costs will be covered by the security that the new customers will be providing." It further submits that these new customers will be making this contribution either through their rates or, alternatively, by forfeiting their security. BC Hydro states that there is virtually no risk that the assets will be stranded before they are paid for. (BC Hydro Final Submission, p. 10)

However, BC Hydro is not actually collecting a contribution from any of the five new customers. Its application of TS 6 to this Project results in a requirement for a deposit only. Many Interveners felt that the new customers should be assessed a contribution and that TS 6 should be found deficient because it doesn't provide for a contribution in this instance. In AMPC's view, TS 6 is not sufficiently robust or well defined to address the high growth scenarios expected in BC today and its intended application by BC Hydro to major projects lacks clarity. (Exhibit C3-10, p. 9)

BC Hydro submits that "…while TS 6 has been in existence since 1991, controversy has arisen now when BC Hydro has sought to apply it to members of a new industry in the province which has not historically been a major user of electricity and has not been typically represented before the BCUC." (BC Hydro Final Submission, p. 15) BC Hydro states that in the past 10 years TS 6 has been applied 23 times, in which 11 cases resulted in a System Reinforcement. In all of these, the offset formula produced a result in excess of the cost of the System Reinforcement. (Exhibit B-22, p. 81)

AMPC stated that all new customers become eligible for postage stamp rates upon receiving service, and should be required to contribute to the cost of the infrastructure with a contribution payment before they can access the stable postage stamp rate. Further, absent the safeguard of a well-designed contribution policy, new customers demanding service in locations that are disproportionally expensive to serve could cause rate shock for all existing customers. A good contribution policy protects existing customers from the risks of such escalation and provides new customers with a price signal to encourage more efficient selection of energy choices.
(Exhibit C3-10, p. 5) (Exhibit C3-12, AMPC 1.2.1, 12.2)

BCSEA submits that whether DCAT is in the interests of current and future ratepayers is largely dependent upon who pays for DCAT and that the five new customers should make a financial contribution to system reinforcement. (BCSEA Final Submission, p. 7)

Air Liquide adopts BC Hydro's submissions regarding TS 6 and further submits that no party has identified an error in the application of TS 6 in this hearing. (Air Liquide Final Submission, pp. 2, 6) ARC, Encana and Murphy Oil, jointly submit that TS 6 has been in force for more than 20 years and should not now be applied any differently than it has in the past. (ARC, Encana and Murthy Final Submission, p. 2) CAPP submits that this application is not the appropriate forum to consider broad, far reaching tariff changes and that this project should be considered in light of the current tariff. (CAPP Final Submission, p. 2)

However, AMPC submits that the Commission can consider whether the outcome of applying TS 6 is in the public interest. In support of this position, it cites section 59(4) and 59(5) of the *UCA*. It further submits that absent a principled mechanism for customer contributions under TS 6, and without an application by BC Hydro to amend TS 6, given the link between customer contributions and project need, the appropriate action for the Commission is to deny BC Hydro's application pending a revised tariff with an appropriate customer contribution policy. (AMPC Final Submission, p. 9)

BC Hydro disagrees, arguing that the Commission has agreed that this hearing is not the place to mount a campaign to modify TS 6. It submits that this hearing should be limited to whether BC Hydro has correctly interpreted the existing provisions of TS 6. (BC Hydro Final submission, p. 16)

Commission Determination

The Commission Panel finds that the calculation of benefits in TS 6 may not accurately reflect the actual economic benefits to BC Hydro's customers. The Panel considers a key determinant of economic benefits to include the full impact of the project on rates. As discussed previously in this Decision, the impact on rates of the project, including the cost of energy depends upon the assumptions of energy surplus. In the absence of a surplus, the impact is high, otherwise it is quite low. The Panel is of the opinion that this may be the result of an out-dated rate structure that doesn't fairly allocate costs between transmission customers and other classes of customers. In any event, the fact that the result of the System Offset calculation in TS 6 does not change, no matter which scenario applies, renders this calculation of little value when considering economic benefits to ratepayers.

Accordingly, the Panel is not persuaded that the economic benefit to BC Hydro and its ratepayers is related in any way to the benefit arrived at in the calculation made pursuant to TS 6. In particular, in the calculation of (R-E) in the System Offset calculation, R includes the revenues from both the sale of energy and the delivery charges, while E only includes some incremental delivery expenses. The Panel notes that this issue was considered by the panel in the System Extension review, and the Guidelines recommend that the cost of energy be included in any benefit calculation.

The approach in TS 6, and applied by BC Hydro to this Project, may be a more appropriate proxy for benefits under different economic circumstances. For example, if the average costs to supply energy to all customers exceeds the marginal cost to acquire incremental energy any increase in load will, generally speaking, drive the average cost down for all customers. In these circumstances, TS 6, which utilizes an estimate of potential gross revenue, less some incremental costs, but not including energy costs, provides a proxy for this load-building benefit. However, if marginal energy generation and/or acquisition costs are greater than average costs, there is no direct economic benefit from building load that will accrue to existing ratepayers. There may be intangible or possible future benefits to increased load. Further, there may be benefits that accrue to BC generally and therefore taxpayers, by the industrial or commercial development that a system extension brings. However, the Panel does not consider that BC Hydro's ratepayers should be financially responsible for benefits that all British Columbians share.

BC Hydro continues to claim that the cost of reinforcing the system will be substantially recovered from new customers to the benefit of existing customers. However, this does not seem likely to the Panel, given that the new customers are providing a deposit, which, if forecast loads materialize, will be refunded. The only scenario in which the new customers would contribute to the reinforcement costs is if they place a deposit and then take no energy – or at least less energy than anticipated.

The Panel agrees with BC Hydro that the deposits from the five customers provide some protection from asset stranding. However, if expected loads are realized in the first few years, the new customers could earn out their deposit in 8 years or less, which, given the uncertainty of the load forecast and the volatile nature of commodity markets, still leaves significant stranding risks. In the event that all deposit monies are refunded, BC Hydro is left with no contribution whatsoever from the new customers and its ratepayers are faced with the full rate impact of the project costs.

The Panel agrees with AMPC that new customers should be provided with price signals that encourage efficient economic decisions. To this end, TS 6 should provide a robust methodology to calculate accurate price signals. Any misalignment of price signals could skew industrial consumers' choices. For example, the absence of a contribution requirement could potentially make an electricity option appear more economical to the gas producers than gas compression, even if natural gas compression, with a carbon tax, is a more economically efficient outcome.

If TS 6 is indeed not robust enough to adequately proportion the costs and risks of transmission reinforcement between existing and new customers in the current economic circumstances, the Panel must determine what, if any, jurisdiction it has to direct a different approach. The Panel has previously determined that issues respecting the application of TS 6 to this project are in scope insofar as they determine the public interest. In addition, section 59 of the *UCA* requires the Commission to determine whether a rate is unjust, unreasonable or discriminatory.

Section 59 of the *UCA*, however, does not provide the Commission with the ability to adjust or change a rate that it has found unjust, unreasonable or discriminatory. Section 58 states that it may determine a just, reasonable and sufficient rate only after a hearing. While this hearing has provided an opportunity for a significant amount of discussion of TS 6, the Panel is not persuaded that it meets the requirements for a hearing as required by section 58(1). This is a CPCN application, not a rate design hearing.

The Panel notes that in the Reasons for Decision accompanying Order G-4-91 (which approved TS 6), the Commission indicated that it was given the assurance that the agreed T&C of the Electricity Supply Agreement and Facilities Agreement would have no financial impact on any other rate classes, stating: "The agreement of the parties, coupled with the lack of inter-class financial impact has been most persuasive in convincing the Commission to accept the negotiated documents." This Panel questions whether BC Hydro has been as diligent as it could or should have been to ensure that as economic conditions changed, rates underwent an appropriate redesign exercise to update TS 6.

In summary, the Panel agrees that there are a number of issues concerning TS 6 that require a more fulsome review. However, the Panel is also mindful that the five new DCAT customers entered the process with BC Hydro in good faith, relying on its expertise with its own tariffs. They have made investments in plant and equipment consistent with receiving electric service. As important as sending accurate economic indicators is, it is equally important, in the Panel's view, to provide prospective customers with fair and predictable treatment. The Panel also notes the following:

1. TS 6 covers only the calculation of contributions and deposits, which amount to a rate impact of considerably less than 1 percent;
2. The rate impact from the incremental energy demand is highly dependent upon surplus power assumptions. From the evidence provided, given the surplus, there will be no impact on rates for the cost of incremental energy until 2017 at the earliest;
3. The Provincial Government expects to review the Transmission Service Rate and the industrial tariff over the next two years, given their age, the BCUC report, and the Province's economic development priorities.

Accordingly the Panel is not persuaded that the CPCN for the Project should be denied pending an amendment of TS 6 as suggested by AMPC. TS 6 has been approved by the Commission, and subsequently has been applied on a number of occasions. There is no evidence before the Panel that any previous issues have arisen in these applications of TS 6.

The Panel also finds that it is not appropriate to alter or modify TS 6, in this instance only, to remedy any perceived shortcomings. For example, if the application of TS 6 does not otherwise result in the requirement for a contribution, it is not appropriate for one to be arbitrarily imposed. However, the Panel will make specific findings and recommendations regarding the interpretation of TS 6 as it relates to generation reinforcement and the Phase 2 project in the following sections.

Panel Recommendation

The Government has indicated a review of industrial rates will be conducted within two years after completion of the BC Hydro F2012-F2014 proceeding or May 2012. **If the review of transmission service rates is not concluded by mid 2014, or if it does not include a review of TS 6, this Panel recommends that the Commission should consider a review of TS 6 and invite all interested parties to participate in the review as this is a significant and urgent issue.**

8.3.3 Generation Reinforcement

Section 2 of TS 6 provides that System Reinforcements do not include any additions or alterations to generation plant and associated transmission, or transmission lines at 500 kV and over, unless the new or incremental loads exceed 150 MV.A. BC Hydro confirms that none of the DCAT Project customers has a load exceeding 150 MV.A. (Exhibit B-22, p. 76) Two issues arose in this proceeding from the approach to generation reinforcement in the application of TS 6. The first is whether the 150 MV.A threshold should apply to the group of new customers as a whole. The second is how the threshold should be applied to a new customer that adds load incrementally over a period of time such that at some point it exceeds 150 MV.A. The Panel specifically requested parties to provide submissions on this issue and also on the issue of whether, in the event that energy to supply the new load came from market purchases or IPPs, the purchase cost should be considered a “generation cost”.

With regard to whether the five new customers should be aggregated, BCPSO submits that TS 6 is an agreement between BC Hydro and individual customers, and should be interpreted as such. (BCPSO Final Submission, p. 25)

Shell submits that the definition of customer in TS 6 is: "*A Customer* is a customer who takes, or is proposing to take electricity from BC Hydro…" and that the whole focus of TS 6 is individual load. It further submits that as Shell is unrelated to any of the other customers, it would be entirely unfair to group Shell with unrelated customers, for the purpose of determining thresholds, would be arbitrary, and discriminatory; and would fail to comply with the terms of TS 6. (Shell Final Submission, p. 14)

Shell has currently committed to 120 MW of load. With regard to the possibility of it taking an additional amount of load, it states that it has identified the possibility of future load in excess of that amount. However, this depends upon whether or not full field development is realized and submits that therefore this is highly speculative. (Shell Final Submission, p. 14)

BC Hydro was asked how it would handle a situation where a customer stages an application with first phase requirement of 100 MW, for an entire service totalling 150 MV.A or greater - would the customer avoid contributing to generation reinforcement costs that would otherwise be payable if all load was added at the same time? It responded that: "… the 150 MV.A provision of TS 6 does not specifically address the timing of incremental load increases. If it appeared that the customer planned to develop the entire project (even though in phased approach) in a relatively short period of time, and had sized its own electrical equipment so as to serve the full, aggregated load, it is likely BC Hydro would treat it as a single "Customer's Plant" and apply TS 6 accordingly. On the other hand, if the customer's plans for expansion, or adding of additional load, were tentative, with the possible additional load being added several years in the future, and subject to other contingencies, then it is likely BC Hydro would not treat it as a single 'Customer's Plant' at the time the application for service was received from the customer." (Exhibit B-30, BCUC 4.3.1)

CEC submits that it is supportive of a pragmatic approach to the determination of compliance with this threshold and submits that the Commission may want to encourage BC Hydro to be more robust in its application of the provisions of TS 6. (CEC Final Submission, p. 22)

BC Hydro agrees, stating: “it is not appropriate to aggregate the load of multiple customers when determining whether the 150 MV.A threshold is met.” (BC Hydro Final Submission, p. 20)

Commission Determination

The Panel finds that the TS 6 should be applied to individual customers, and not an aggregation of customers. The Commission Panel notes that BC Hydro has also aggregated the new customers for the purpose of calculating project costs, before proportioning these costs according to their estimated load requirements. The Panel is of the view that this is an appropriate approach. However, any specific application of the terms and conditions of TS 6 must be done on an individual customer basis.

With regard to a customer that takes additional load subsequent to the TS 6 calculation, the Panel also considered the policy underlying the Customer Base Line as a comparison. In this case, the customer’s first tier rate applies to an amount of energy that is determined by an analysis of their historic load. However, when undergoing an expansion, due, for example, to an economic upturn and an increased demand for product, a customer is entitled to apply to have the baseline reset at a higher value. This approach recognizes that tariffs are generally applied in such a way that changed or changing circumstances are taken into consideration in their application. **Accordingly, the Panel also finds that it is appropriate to consider load added subsequent to the new customer taking service when applying TS 6.**

While the Commission Panel agrees with a pragmatic approach, it considers BC Hydro’s “wait and see” approach to additional load to lack transparency and clarity. In particular, the Panel is of the opinion that there should be a specified time period during which the calculation remains open for adjustment during that period. The Panel notes that TS 6 provides a benefit for the five new customers in the event that additional new customers attach to the system within 5 years. In this eventuality, their deposit is recalculated and refunded by an amount that recognizes the additional new load. The Panel also notes other sections of TS 6 which implicitly recognize a time period, such as the benefit calculation, which extrapolates first year benefits over 7.4 years and the refund calculation, which provides for, all else equal, deposit refunds in 8 years.

Panel Recommendation

The Panel makes no specific directive with regard to the inclusion of generation reinforcement in the TS 6 calculation in the event that any of the five industrial customers increase the amount of load. However, the Panel recommends that this issue be examined in the forthcoming industrial tariff review.

8.3.4 Tariff Supplement 6 and GDAT Project Costs

Having approved BC Hydro's phased approach to the DCAT project as a means of meeting its MRS commitments, the issue now for the Commission Panel is whether the system reinforcement costs, for the purpose of the calculations of deposits/contributions in TS 6 should include estimates for GDAT.

BC Hydro has not sought any deposit or CIAC with regard to the GDAT project from any of the five new customers. It submits that all five of these new loads will be served prior to the implementation of GDAT and at that time these customers will be treated as would any other existing customer. It argues that it would be incorrect to include GDAT costs. It further argues that even if it were to do so, the increase in project cost would not trigger the need for a contribution. (BC Hydro Final Submission, p. 22)

CEC argues that customer security is being based on a project cost estimate for a project which does not deliver the required N-1 level of service. There is an implied commitment by BC Hydro to provide the Stage 2016 project, which the customers can rely on but they are not being asked to commit security on the basis of the full costs required to provide the service. Consequently other customers on the BC Hydro system will be more at risk than they should be. It also argues that the customers putting up security will be relieved of the security commitment on the basis of their full revenues against a partial security commitment, thus relieving them more quickly than would otherwise be the case, again this raising the risk to the other BC Hydro customers. (CEC Final Submission, p. 10)

CEC further submits that "The GDAT project as undefined as it may be is clearly defined by the requirement to meet the N-1 standard of service for the Dawson Creek Chetwynd area loads. To the extent that this represents costs for investments in future stages there should be nothing in the 'estimating' approaches or 'subsequent reinforcement' approaches which prevents the Commission from identifying the public interest in the fairness involved in considering the DCAT and GDAT projects within this CPCN. BC Hydro's submission that the GDAT is not before the Commission is not the case. In the CEC's submission the 2016 Common Stage 2 is clearly a part of the CPCN application." (CEC Final Submission, p. 25)

With regard to the relationship between the DCAT and the potential $114 million GDAT projects, AMPC stated that if both facilities proceed, and if both facilities receive the same tariff treatment, then up to $335 million in new infrastructure, 76 percent to 90 percent attributable to new industrial facilities, will escape a reasonable level of customer contribution obligation. It further noted that this outcome is inconsistent with the user pay/cost causation principle that customer contribution policies (including TS 6) are intended to give effect to. (Exhibit C3-10, pp. 10-11)

AMPC also submits that the GDAT project must be considered, as it forms an integral part of BC Hydro's plans to provide adequate service to customers in the area and that "…. BC Hydro should not pretend that GDAT does not exist because its final configuration is imprecise." (AMPC Final Submission p. 20)

BC Hydro replies that TS 6 does not contemplate "the indefinite future" in determining customer contributions. If customers are fortunate enough to take service at a time when their load can be served without any system reinforcement costs being incurred, no contribution will be required. However, if they take service at a time when a specific project is required, they will be required to make a contribution or to provide security. In no circumstances are they required to make contributions based on expected future increases in load, if has BC Hydro has not yet determined what facilities will be necessary to serve that load. It further argues that there is no right, under TS 6 for BC Hydro to charge customers for "… possible future specific assets that have not been identified." (BC Hydro Reply Submission, pp. 5-6)

In contrast to the position of other Interveners, BCSPO submits that since DCAT can only supply 73 MW of this load at the required N-1 reliability condition, this is the value that should be used in the determination of the BC Hydro offset. The balance of the 176 MW (i.e., 103 MW) is part of what is driving the need for the GDAT project and should be linked to that project and not DCAT. In order to credibly use the 176 MW in the offset calculation, the cost being offset would have to include both the DCAT and GDAT projects, which is not precisely known at this time. (BCSPO Final Submission, p. 20)

Commission Determination

The Panel finds that the DCAT Project TS 6 calculation should not include the estimated costs of the Phase 2 GDAT project. The scope and timing of GDAT is uncertain at this time – the timing being heavily dependent upon the materialization of the load forecast.

The service provided to the five new industrial customers by the DCAT project and the incremental increase in reliability resulting from a future GDAT project create issues for this or possibly future Commission Panels to consider. One such issue is whether there is an obligation to provide future N-1 service to a new network-connected customer that elects to receive N-0 service by providing a security deposit for a less expensive project than that required for full N-1 service. If an obligation does exist, or the customer later demands N-1 service, then another issue arises as to whether a security deposit is required for any required reinforcements. If there is no obligation, then can BC Hydro rely on the controlled load shedding of network connected load indefinitely to remain compliant with Mandatory Reliability Standards?

The Panel has previously found that BC Hydro can meet its MRS reliability obligations through load shedding agreements, such as the ones it currently has in place with the five new customers. BC Hydro has stated its intention to provide full N-1 service through the second project phase following the completion of DCAT and that at that time, the five new customers should be treated as would any other existing customer. In this regard, the Panel notes the potential applicability of TS 6 to existing customers. TS 6 defines “customer” as: “A customer who takes or is proposing to take Electricity from B.C. Hydro pursuant to an Electricity Supply Agreement on the terms and conditions of Rate Schedule 1821, as amended or replaced from time to time." The Panel is of the opinion that customers should not be relieved of their full deposit or contribution responsibility merely because a project is phased, instead of being completed at one time. **Accordingly, the Panel determines that if the Phase 2 GDAT project is found to be needed in order to provide service to these five new industrial DCAT customers, the requirement for additional deposit or contribution should be assessed at that time.**

The Panel takes no position on whether full N-1 service is at the customers' option, or whether BC Hydro can require customers to "upgrade" to this service from the "interruptible" service they will be taking when and if the GDAT project goes ahead. Further, any GDAT deposit/contribution requirement may also be shared by other customers that attach between DCAT and GDAT. This will not be clearly known until the GDAT project is brought forward to the Commission by BC Hydro. The issue before this Panel is whether to approve the CPCN for phase one – DCAT – therefore this issue of deposit or contribution for GDAT is one that the future panel assessing the GDAT project will be in a better position to consider. Accordingly, this Panel makes no determination about whether the five new customers should be reassessed when the DCAT project begins.

Panel Recommendation

1. **The forthcoming industrial rate review should consider how deposits and contributions should be assessed when a project is phased.**
2. **The issue of additional deposits/contributions by DCAT customers should be examined by a future Panel when the Phase 2 GDAT CPCN application is heard.**

8.4 Proposed Revisions to the Electric Tariff

The Electric Tariff does not currently contemplate distribution customers providing security for transmission reinforcement. In this Application, BC Hydro seeks to make revisions to the Electric Tariff to require customers to do so. (Exhibit B-1, p. 2-20)

Two industrial customers (of the five new industrial customers) will take power at distribution level voltage. The result of applying the Electric Tariff as currently drafted would be to require security for the transmission reinforcements from the three transmission customs but not from the two distribution customers. Similar provisions as those in TS 6 exist under the Electric Tariff T&C for distribution customers but relate only to distribution reinforcement costs not transmission reinforcement costs.

BC Hydro states that "[t]o resolve this inequity and to protect existing customers against the risk of over capacity if new customers choose not to use electricity for compression, BC Hydro is applying to revise its Electric Tariff to permit it to recover security for the costs of transmission reinforcements from appropriate distribution customers. The revision to the Electric Tariff T&C will permit BC Hydro to recover from distribution customers that seek new service in excess of 10 MW some of the costs of transmission reinforcement made necessary, in whole or in part, by the new load." (Exhibit B-1, p. 2-20)

BC Hydro submits that these changes will ensure that new large customer loads are treated equally whether they choose to take power at distribution or transmission voltage. (Exhibit B-1, p. 2-19) Specifically, BC Hydro is seeking an order to revise section 8.3 of the Electric Tariff T&C as reflected in the amendments set out in Exhibit B-1, Appendix A (Draft Order).

The additional language that BC Hydro has proposed to include in section 8.3 is as follows:

> "In addition to any Extension Fee and revenue guarantee to be paid or provided by a Customer pursuant to this part, for new service that:
>
> (a) Have a total expected Maximum Demand greater than 10,000 kW; and

(b) Partially or wholly make necessary System Reinforcement (as defined in Tariff Supplement No. 6) to the transmission system in order to provide service to the distribution system to which the Customer is or will be connected:

the customer will be subject to the terms and conditions of Tariff Supplement No. 6 in respect of System Reinforcement, including the requirement to provide security for the cost of the System Reinforcement in accordance with Tariff Supplement No. 6."

BC Hydro submits that the proposed revisions are fair and reasonable and prevent undue discrimination between distribution customers with large loads that require transmission system reinforcement and their transmission customer counterparts. It further submits that this approach is not discriminatory to new distribution customers because there are no existing distribution customers on the system that have required transmission system reinforcement. (BC Hydro Final Submission, p. 25)

In the Application, BC Hydro did not specifically identify the sections of TS 6 that are in respect to 'System Reinforcement'. In response to Exhibit B-5, BCUC 1.50.1 BC Hydro states that: "If the requested amendment to the Electric Tariff is approved, distribution customer's with loads equal or greater than 10 MW that require BC Hydro to undertake System Reinforcement will be subject to all of those sections in the Tariff Supplement No. 6 that relate to System Reinforcement. For example, clause 13 concerning the type of security for costs will be applicable, as will sub clause 4(c) concerning the estimating of System Reinforcement costs."

BC Hydro listed the additional TS 6 clauses that would be applicable to distribution customer's with loads equal or greater than 10 MW that require BC Hydro to undertake System Reinforcement as:

1. Clause 1(b)(i) – states that BC Hydro is responsible for System Reinforcement;
2. Clause 2 – definition of System Reinforcement;
3. Clauses 4(c), (d) and (e) – sets out BC Hydro's requirements to provide detailed;
4. Cost studies;
5. Clause 9(a)(i) – sets out that Right-of-Way costs are included in System;
6. Reinforcement costs;

7. Clause 9(c) – defines what is included in Right-of-Way; and
8. Clause 14 – Defines Force Majeure events that could impact on System Reinforcement construction.

(Exhibit B-14, BCUC 2.21.1)

However, BC Hydro is not proposing to make any actual changes to the Electric Tariff to specifically identify each section of TS 6. BC Hydro stated that it would be opposed to specifically identifying each section of TS 6 that would apply to distribution customers considering the small number of customers to whom the revised wording would apply and the extra complexity it would add to the Electric Tariff. (Exhibit B-14, BCUC 2.21.2)

Under the Electric Tariff, a distribution customer is only required to make a contribution to System Improvements if their expected maximum demand is greater than 500 kVA. BC Hydro also provides an offset to the customers Extension costs, but in contrast to transmission customers, the Electric Tariff contains no need for any security to be posted by the distribution customer against BC Hydro's contribution. Design estimates of the 25 kV distribution system upgrades and costs required to connect the two customers are underway and the costs are not available. (Exhibit B-5, BCUC 1.51.1, 1.51.3)

The BCPSO raises an issue of how the Distribution Customers should be treated in the TS 6 deposit calculation. Under the proposed treatment, the anticipated revenues from these distribution customers is counted twice – once for the transmission offset, once for the distribution offset. (BCPSO Final Submission, p. 17)

However, in the IR process, BC Hydro stated: "BC Hydro believes that it is appropriate to include distribution revenue in the offset calculation because distribution customers will be required to pay or post security for transmission upgrades on the same basis as transmission service customers." (Exhibit B-30, BCPSO 4.17.1) It elsewhere stated that even if the deposit was recalculated to account for the double counting of revenues, it does not consider the result to have a material financial impact. (Exhibit B-30, BCPSO 4.17.2) BC Hydro calculated that if the revenue from the two distribution customers is removed, the annual revenues from the five DCAT customers of

$58 million (shown in the response to BCUC 2.19.2) would decrease to $48 million and the maximum offset under TS 6 would decrease from $429 million to $355 million.

In reply, BC Hydro submits that it is not the purpose of this hearing to set an appropriate precedent for interpreting TS 6 and that unless a "proper interpretation" of TS 6 would provide for a significantly different contribution, the decision to issue a CPCN is not affected. (BC Hydro Reply Submission, p. 8)

BCPSO argues that BC Hydro has firmly stated (Exhibit B-22, p. 85), that TS 6 is meant to be applied on an individual customer basis and that if the distribution customers' revenues are used to offset distribution system reinforcements then a financial contribution should be required for the transmission system reinforcement. (BCPSO Final Submission, p. 18)

BC Hydro made no rebuttal in their Reply Submission.

Commission Determination

The Commission Panel is not approving the revision to section 8.3 of the Terms and Conditions of the Electric Tariff as proposed by BC Hydro at this time.

The Commission Panel agrees that distribution customers taking a large load, thus triggering a transmission reinforcement, should be treated in the same manner as a transmission customer that does the same. The Commission Panel is satisfied that in general, the proposed changes to the Electric Tariff are fair and reasonable and provide greater protection for BC Hydro Ratepayers. However, the Panel has concerns about how these changes are worded, in addition to other aspects of the proposed changes to the Electric Tariff. The Panel may be prepared to accept the proposed changes subject to the following clarifications.

(i) Double Counting Customer Benefits

The Commission Panel agrees with the BCPSO that there is a potential for the calculation of the distribution Extension Fee to be based on the same new customer load that the transmission deposit/contribution calculation in TS 6 is based on. If this occurred, it would amount to double counting the benefits and the Commission Panel concurs that this should be avoided. However, it is not clear from the evidence before the Panel whether that is or will be the case for the two distribution customers because the proposed changes to the Electric Tariff do not address the issue of allocation of the benefits of the new load across the distribution and transmission calculation. Accordingly, the Panel requires further clarifications to the Electric Tariff to specify how the new customer load is to be allocated across the two tariffs for the purpose of these calculations.

(ii) Wording Clarification

The Commission Panel finds the proposed revised wording vague and states only that distribution "customers will be subject to Tariff Supplement No. 6 in respect of System Reinforcement......" The Commission Panel disagrees with BC Hydro's position that specifically identifying the applicable sections of TS 6 would add unnecessary complexity to the Electric Tariff; in fact the Panel is of the opinion that it would make the Electric Tariff clearer and less subject to interpretation. Under BC Hydro's proposed Electric Tariff wording it would be up to the customer to ascertain which sections of TS 6 relate to System Reinforcement. This could lead to confusion and result in interpretation discrepancies in the future. The Commission Panel requires BC Hydro to provide revised amended language for the Electric Tariff T&C section 8.3 which specifically identifies each section of TS 6 that is in respect to System Reinforcement for the Commissions further review.

With regard to BC Hydro's assertion that BCPSO's analysis of the calculation of distribution customer's deposits is irrelevant and inappropriate, the Panel disagrees. While it may or may not be a purpose of this hearing to set an "appropriate precedent" for interpreting TS 6, it is the purpose of this hearing to analyze how TS 6 is applied to this project. In its determination on generation costs, the Panel has already found that TS 6 is to be applied to individual customers and not to a group of customers. There is nothing to persuade the Panel that this principle shouldn't apply to all of the deposit/contribution and refund calculations. **Accordingly, the Commission Panel directs BC Hydro to recalculate the deposit/contribution requirement under TS 6, and, if applicable the Electric Tariff, for each DCAT customer and file the revised calculation with the Commission.**

9.0 ABORIGINAL CONSULTATION

This Section of the Decision explores the adequacy of BC Hydro's consultation with aboriginal peoples on the Project. The focus is primarily on the West Moberly First Nation, which was the only First Nation to actively intervene in this proceeding. A significant amount of the evidence on First Nations consultation was submitted as confidential in this proceeding. Where that evidence has been referenced in this section, it is for context only and does not contain any sensitive information.

9.1 The Duty to Consult

9.1.1 The Crown's Duty

As a Crown Corporation, BC Hydro has a duty to consult First Nations whenever it contemplates an activity that could potentially impact aboriginal or treaty rights. This duty is grounded in the honour of the Crown, a principle requiring the Crown to act with integrity and honour and avoid "even the appearance of sharp dealing" in all its dealings with aboriginal peoples, including the dealings of treaty making and treaty interpretation. (paraphrased from *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73 (*Haida Nation*), paras. 16 and 19)

The duty to consult is triggered when the Crown has knowledge, actual or constructive, of the rights asserted under section 35(1) of the *Constitution Act, 1982* which states, in part, "[t]he existing aboriginal and treaty rights of the aboriginal peoples of Canada are hereby recognized and affirmed."

9.1.2 Reciprocal First Nations' Duty

While the Crown has a duty to consult and accommodate First Nations, First Nations have an obligation to participate in the consultation in good faith, without frustrating the consultation process. The Court in *Halfway River First Nation v. British Columbia (Ministry of Forests)*, 1999 BCCA 470 (*Halfway River*) said:

> "There is a reciprocal duty on Aboriginal peoples to express their interests and concerns once they have had an opportunity to consider the information provided by the Crown, and to consult in good faith by whatever means available to them. They cannot frustrate the consultation process by refusing to meet or participate, or by imposing unreasonable conditions." (para. 161)

In *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage),* 2005 SCC 69 (*Mikisew*), the Supreme Court of Canada reiterates this, stating:

> "It is true, as the Minister argues, that there is some reciprocal onus on the Mikisew to carry their end of the consultation, to make their concerns known, to respond to the government's attempt to meet their concerns and suggestions, and to try to reach some mutually satisfactory solution." (para. 65)

9.1.3 The Commission's Role

The Commission's role is to assess the scope of the Crown's duty to consult First Nations and make a determination as to the adequacy of consultation with First Nations up to the point of the Commission's decision on the CPCN application. This role has been confirmed by the Supreme Court of Canada in *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council, 2010 SCC 43* (*Rio Tinto Alcan*, para. 74) and by the BC Court of Appeal in *Kwikwetlem First Nation v. British Columbia (Utilities Commission)*, 2009 BCCA 68 (*Kwikwetlem*, paras. 13, 15 and 70).

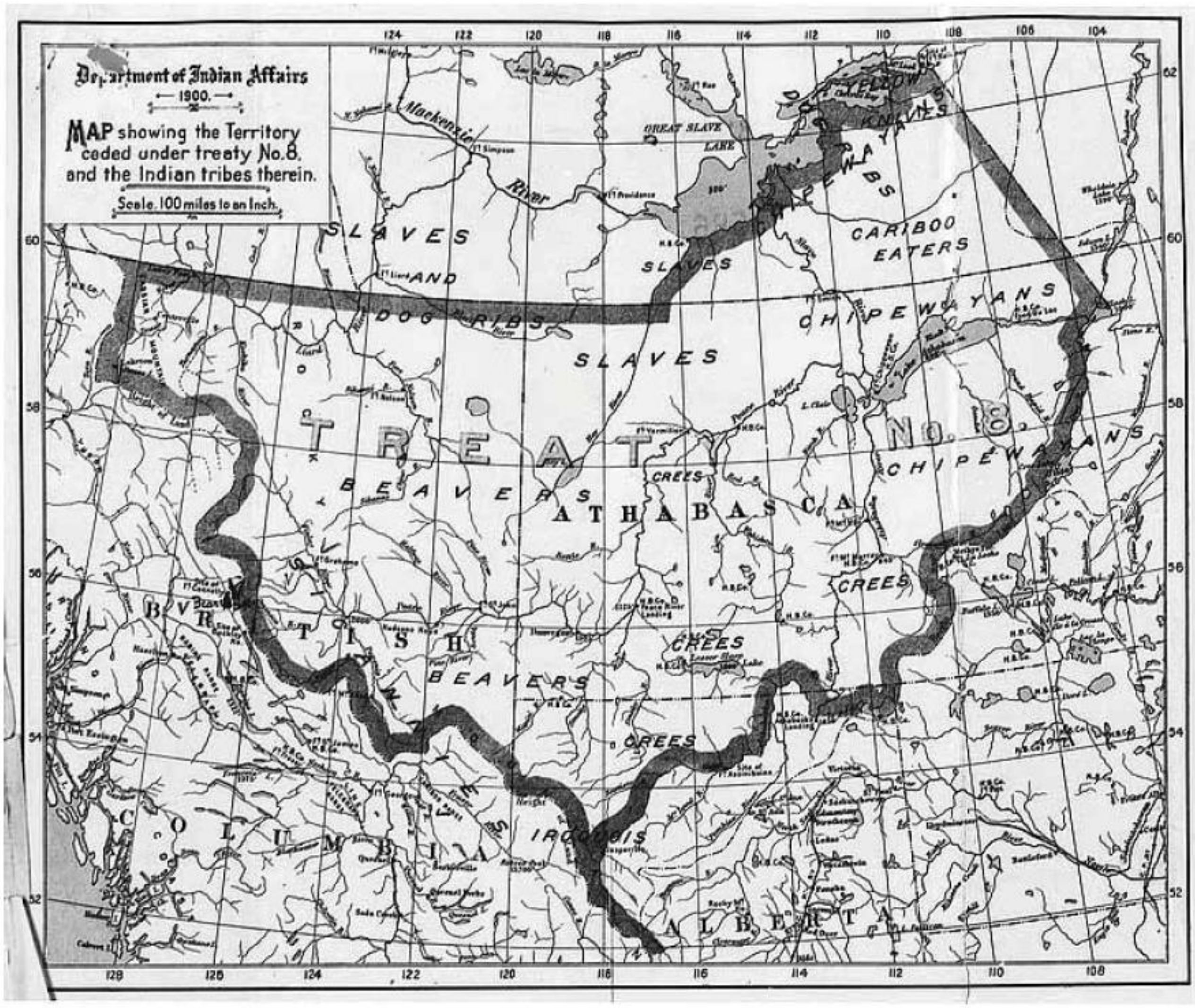
9.2 Identification of Potentially Impacted First Nations

9.2.1 Treaty 8

The first step of consultation is for the Crown to determine which First Nations may potentially be impacted by the Project. BC Hydro identified that the Project Area lies within the boundaries of historic Treaty 8.

Treaty 8 was originally signed in 1899. It was the last of the numbered treaties signed by the federal government during the expansion of confederation in the late 1800s.

Treaty 8 encompasses 840,000 square kilometres, an area extending from northeast British Columbia, across northern Alberta, northwest Saskatchewan and the southern Northwest Territories.



Source: Exhibit B-1, p. 6-3

The treaty itself is a short document, which includes:

> "And Her Majesty the Queen hereby agrees with the said Indian that they shall have right to pursue their usual vocations of hunting, trapping and fishing throughout the tract surrendered as heretofore described, subject to such regulation as may from time to time be made by the Government of the Country…on saving and excepting such tracts as may be required or taken up from time to time for settlement, mining, lumbering, trading or other purpose."

Due to the brief nature and historic language of Treaty 8 the Courts have been called upon to interpret the treaty in a modern context. The Supreme Court of Canada (SCC) in *R. v. Badger, 1 S.C.R. 771 (Badger)* held that:

> "the words in the treaty must not be interpreted in their strict technical sense nor subjected to rigid modern rules of construction. Rather, they must be interpreted in the sense that they would naturally have been understood by the Indians at the time of the signing." (para. 52)

At the time of the treaty little settlement or development was anticipated for the region, and the SCC held that:

> "No doubt the Indians believed that most of the Treaty No. 8 land would remain unoccupied and so would be available to them for hunting, fishing and trapping." (Badger, para. 57)

Additionally, the SCC has held that the oral promises made to First Nations at the time of signing the treaty must also be considered in interpreting the content of the treaty (*Badger*, para. 52). Therefore, in the case of Treaty 8, the 1899 Report of the Treaty Commissioners, which describes the oral promises made during the historic negotiations, must also be considered:

> "We had to solemnly assure them that only such laws as to hunting and fishing as were in the interest of the Indians and were found necessary in order to protect the fish and fur-bearing animals would be made, and that they would be as free to hunt and fish after the treaty as they would be if they never entered into it." (Treaty No. 8 Made June 21, 1899 and Adhesions, Reports, Etc., Land Publication No. QS-0576-000-EE-A-16)

The Courts have interpreted the oral promises made at the time of the Treaty 8 signing as a guarantee of continuity in traditional patterns of economic activity and occupation. (*Mikisew*, para. 47)

The Crown's right to take up lands under Treaty 8 "is subject to its duty to consult and, if appropriate, accommodate First Nations' interests before reducing the area over which their members may continue to pursue their hunting, trapping and fishing rights". (*Mikisew,* para. 56) As part of that duty the Crown must inform itself of the impact its activity will have on the exercise of treaty rights and communicate its findings to the First Nation. As stated in *Mikisew* paragraph 55:

> "...the Crown is nevertheless under an obligation to inform itself of the impact its project will have on the exercise by the Mikisew of their hunting and trapping rights, and to communicate its findings to the Mikisew. The Crown must then attempt to deal with the Mikisew "in good faith, and with the intention of substantially addressing" Mikisew concerns (*Delgamuukw*, at para. 168). This does not mean that whenever a government proposes to do anything in the Treaty 8 surrendered lands it must consult with all signatory First Nations, no matter how remote or unsubstantial the impact. The duty to consult is, as stated in *Haida Nation*, triggered at a low threshold, but adverse impact is a matter of degree, as is the extent of the Crown's duty."

9.2.2 Treaty 8 First Nations

In British Columbia there are eight First Nations that are signatories to Treaty 8: McLeod Lake Indian Band (McLeod Lake), Saulteau First Nation (Saulteau), Blueberry River First Nation (Blueberry River), West Moberly First Nation (WMFN), Prophet River First Nation (Prophet River), Doig River First Nation (Doig River), Halfway River (Halfway River) and Fort Nelson (Fort Nelson) First Nations.

Through a search in the Government of British Columbia's Consultative Area Database, BC Hydro identified that of the eight BC Treaty 8 First Nations, four have rights in the Project Area: McLeod Lake, Saulteau, Blueberry River and WMFN. BC Hydro initially determined that the others do not have interests or rights within the Project Area. However, sometime into the Project consultation BC Hydro learned that Prophet River and Doig River First Nations are involved in the review of other applications for Crown tenure in the Project area, suggesting they too have interests or rights in the Project Area.

9.3 BC Hydro's Consultation with West Moberly First Nation

This section assesses BC Hydro's consultation with WMFN, a First Nation with specific concerns about its treaty rights, which they have identified as a registered Intervener in this Application. Consultation with the remaining First Nations identified by BC Hydro, as having interests and rights in the DCAT Project area, will be discussed in the subsequent section.

9.3.1 The Scope of Duty to Consult

The scope of consultation and accommodation owed to a First Nation will vary case by case along a spectrum from low to high (the *Haida* spectrum*)*. The level of consultation along the spectrum in a given case depends on the strength of the Aboriginal right and the severity of the potential impact on those rights, although each case should be approached individually because the level of consultation may change as information is discovered in the consultation process (*Haida Nation*, para. 45).

9.3.1.1 WMFN's Treaty Rights

WMFN's ancestors, the Hudson's Hope Indian Band, became adherents to Treaty 8 in 1914 (Exhibit C5-20, pp. 36-40) and thus WMFN became party to the rights established under the Treaty namely "hunting, trapping and fishing throughout the tract surrendered". As discussed in Section 9.3 above, the Supreme Court of Canada has interpreted that Treaty 8 rights were established at the time of treaty signing with the intention that the First Nations' rights to hunt, fish and trap would continue after the treaty as existed before it (*Badger*, para. 39).

Historically WMFN hunted and trapped ungulates such as moose and caribou, as well as grizzly bear and beaver among other species. They also fished for species such as bull trout and gathered plants and berries for food and medicines. WMFN continues to exercise these same rights in the present, although because the caribou population has significantly decreased, they have voluntarily placed a moratorium on hunting caribou in an effort to recover the species to a sustainable size that can support a hunting practice. (Exhibit C5-20, pp. 47-67, 115)

Currently, for WMFN the hunting, fishing and trapping rights of Treaty 8 include the continuation of the exercise of their rights within their traditional hunting grounds, which they term as their "seasonal round". In oral testimony WMFN explained that a seasonal round is the mobility pattern of a First Nation throughout the region. Travel is linked to deliberate land use activities, including hunting, trapping, fishing and gathering. The seasonal round is not rigid, but rather changes from year to year, adapting to the ecosystem and wildlife patterns. However, the broad outline and area of the seasonal round tends to be consistent over time. WMFN's seasonal round transverses the Project Area. In particular, WMFN maintains that the Pine River habitat is integral to the stability of the seasonal round. (Exhibit C5-20, pp. 50-56, 131; T1-Proceeding: 333-340)

9.3.1.2 Assessment of Impact and Scope of the Duty to Consult

Both BC Hydro and WMFN agree that no strength of claim assessment for Aboriginal or treaty rights is needed in this case because WMFN has established treaty rights under Treaty 8. (WMFN Final Submission, p. 23, BC Hydro Reply Submission, para. 73) Thus, the scope of the duty to consult hinges on the impact of the Project on WMFN's treaty rights (BC Hydro Final Submission, p. 30, WMFN Final Submission, p. 23)

This section discusses what should be considered in determining the impact of the project, and the different views of BC Hydro and WMFN regarding the impacts of the Project on WMFN's treaty rights. This section concludes with a determination of the impact, and the corresponding scope of the duty to consult (which is directly proportional to the impact).

9.3.1.2.1 Impact of the Project

The Courts have given some guidance on assessing impacts on rights. In *Haida Nation* the Court referred to a spectrum of the degree of impacts: a low degree of impact is when "the potential for infringement is minor" and a high impact is when the "potential infringement is of high significance to the Aboriginal peoples, and the <u>risk of non-compensable damage is high</u>" (emphasis added, para. 44).

The Courts have also provided guidance on which impacts should be the subject of consultation. In *Rio Tinto Alcan* the Supreme Court of Canada clarified that consultation is not a vehicle to address past wrongs, and should be limited to the specific proposal or decision being contemplated, excluding adverse impacts of past developments which the project may be said to be a part (para. 52).

In *West Moberly First Nations v. British Columbia (Chief Inspector of Mines)*, 2011 BCCA 247 (*West Moberly*) the Court discussed the concept of cumulative impact. *West Moberly* distinguished the circumstances in *Rio Tinto Alcan,* pointing out that no new impacts were derived from the contemplated activity in that case; however, in cases where the current contemplated activity results in new adverse impacts, past effects are relevant in order to fully understand the severity of the new effects, and the existing state of affairs (paras. 116, 117).

For contemplated activity that is causally linked to new adverse impacts, Chief Justice Finch in the *West Moberly* decision held that the "historical context is essential to a proper understanding of the seriousness of the potential impacts" (para. 116). He explains:

> "To take those matters into consideration as within the scope of the duty to consult, is not to attempt the redress of past wrongs. Rather, it is simply to recognize an existing state of affairs, and to address the consequences of what may result from pursuit of the exploration programs." (*West Moberly*, para. 119)

Therefore, cumulative effects should be considered to fully comprehend the existing state and to place the new impacts in the proper context to understand the degree of impact.

Chief Justice Finch also discussed future impacts when he stated:

> "I am therefore respectfully of the view that to the extent the chambers judge considered future impacts, beyond the immediate consequences of the exploration permits, as coming within the scope of the duty to consult, he committed no error. And, to the extent that MEMPR failed to consider the impact of a full mining operation in the area of concern, it failed to provide meaningful consultation." (West Moberly, para. 125)

9.3.1.2.2 BC Hydro's View of Project Impacts

BC Hydro anticipates the potential direct impacts arising from the Project on WMFN's treaty rights are low. (BC Hydro Final Submission, p. 30) In making this assessment BC Hydro submits it considered impacts to the land including the following:

- 20% of the line will be located on Crown land while 80% will be located on private land (Exhibit B-1, p. 6-12);
- approximately 14.8 km or 20% of the proposed line will not parallel existing infrastructure (Exhibit B-5, BCUC 1.5.3);
- about 50% of the length of the line would be located on previously disturbed, anthropogenic surfaces- that is, land that has already been cultivated, cleared for pasture, or built on with structures while the other 50% would require previously undeveloped land (Exhibit B-5, BCUC 1.5.4, 1.6.1);
- approximately 55 km of the existing 138 kV transmission line will be removed as a result of the Project (Exhibit B-1, p. 6-13); and
- it is 19 km away from the closest reserve (Exhibit B-5, BCUC 1.6.1).

BC Hydro considered impacts to the environment including fish, wildlife and wetlands, and to activities such as trapping, hunting and fishing. As part of this process BC Hydro contracted AMEC Americas Limited to conduct an Environmental Overview Assessment of the Project. At the outset of the EAO, AMEC chose Valued Ecosystem Components and Valued Social Components to study. A VEC is defined as part of the environment that is identified as having scientific, cultural, or economic importance. (Exhibit B-34, p. 8; Exhibit B-1, Appendix F, p. 66) AMEC submits that VECs and VSCs are key indicators of a healthy ecosystem and community, for which project-related impacts are estimated. (Exhibit B-1, Appendix F, p. 43)

BC Hydro stated that “AMEC identified relevant VEC’s and VSC’s [*sic*] based on their experience and expertise. The VEC/VSCs were selected to represent resources of known sensitivity and value.” (Exhibit B-6, WMFN 1.8.1) Some of the VECs/ VSCs chosen include, but are not limited to: fish and aquatic resources such as surface water quality and Bulltrout; vegetation such as at risk plant species; soils; wildlife such as the Western toad and Northern Myotis bat; wildlife habitat, mainly wetlands; and archaeological resources such as artifact scatter and historic sites.

In oral testimony, Mr. Slaney explained the consideration his team gave to the impact of the Project in the context of past industrial activity in the area. He stated:

> "Throughout the process, the team were looking at existing pre-project conditions. So, when they looked at the land, they were looking at the changes that had happened. So there was a record of the fact that this has been cleared, or this is in some state of regeneration or those kind of things. So there was a recognition that change had happened. On the other hand, we were not particularly trying to document that change over time." (T2:604)

Mr. Slaney's assessment of past industrial development is that "past developments have decreased the impact of the project, because as I said earlier, we are looking at a lot of disturbed land." (T2:606)

In the EOA, AMEC concluded that after mitigation, the Project will have a low or negligible effect on almost all VECs and VSCs. (Exhibit B-1, p. 5-2) Specifically, the EAO suggests that there will be no adverse residual effects on fish and fish habitat or soils and that residual effects on vegetation and wetland habitat, including ecosystem alterations, invasive species, and habitat fragmentation will be low after mitigation. (Exhibit B-1, pp. 5-12, 5-14, 5-15) Similarly, the EAO identifies potential effects on wildlife, including the loss of habitat, sensory disturbances, increased access by hunters and predators, and increased mortality; however, the EAO findings indicate that after mitigation these effects will also be low. (Exhibit B-1, pp. 5-14, 5-15)

AMEC did not include moose and other ungulates as wildlife VECs because wetlands, the preferred habitat of moose, were included as a VEC. (T2:596; Exhibit B-39) During the oral hearing, BC Hydro submitted a list of wildlife that was left out of the EAO in error. The list indicated that moose, elk and deer were excluded as VECs because, in part, they are common in the study area and their habitat was avoided or was already a VEC. (Exhibit B-39) In July 2012, BC Hydro submitted an evidentiary update in this proceeding which included a study on moose ("Moose Habitat Management and Mitigation Plan for the Dawson Creek/Chetwynd Area Transmission (DCAT) Project - Draft Report, July 2012") from AMEC which indicates that moose continue to be abundant in the region. The study identifies two key residual (after mitigation) effects to moose as a result of the project. The first residual effect to moose is direct and indirect changes to habitat, including loss, alteration, fragmentation or disturbance of habitat. The second residual effect is increased access to moose by predators and hunters, thereby increasing the potential of mortality. However, AMEC qualifies these residual effects as non-significant. (Exhibit B-34, Appendix B, pp. 21, 23, 26)

BC Hydro submits that the Moose Study corroborates the findings in the original EOA. (BC Hydro Reply Submission, p. 18)

With respect to effects on hunting, trapping and recreational fishing, BC Hydro states that access to some sites may be temporarily disrupted during construction, but this will primarily only occur at active construction sites, and the impact to hunters, trappers and fishers is considered to be low after mitigation. (Exhibit B-1, p. 5-20) Regarding archaeological impacts, BC Hydro initiated an Archaeological Impact Assessment and BC Hydro intends to implement all mitigation recommendations therein, such as site avoidance, in order to prevent any impacts to these sites during Project construction or operation. (Confidential Exhibit B-42, p. 198)

In summary Mr. Slaney expressed:

> "the project has a relatively small footprint. Part of the existing line is going to be allowed to regrow and a new line has only a slightly larger footprint than the old one so it shouldn't make a material change." (T2:608)

On July 5, 2012 WMFN submitted its final Impact Assessment Study (IAS) in the proceeding. In oral testimony BC Hydro stated that the IAS brought new information to light, particularly regarding the seasonal round and historic trails. In particular, Ms. Dutka, BC Hydro's Project Manager for DCAT, stated multiple times that BC Hydro did not know enough about the seasonal round, but was willing to work with WMFN on these issues. (T2:575, 667, 702-3) However, in its Final Submission in this proceeding, BC Hydro submits that "the information received has not caused it to vary its original assessment that any potential impacts arising from the DCAT Project will not be significant on the WMFN's treaty rights." (BC Hydro Reply Submission, p. 22) With respect to the IAS, BC Hydro contends that the assessment does not provide any "specific details as to the precise nature of the impact" and lacks "concrete evidence". (BC Hydro Reply Submission, pp. 17-18)

Regarding cumulative impacts, BC Hydro understands that the *West Moberly* case directs that cumulative impacts should be considered "where contemplated conduct may limit the extent to which the Crown can achieve reconciliation in connection with its past conduct." (BC Hydro Reply Submission, p. 14) BC Hydro submits that "the evidence does not establish a link between the current conduct contemplated by BC Hydro and the consequences of past interference with WMFN treaty rights in the way that the Court found existed in *West Moberly.*" (BC Hydro Reply Submission, p. 14)

With respect to the consideration of future impacts beyond the immediate consequences of the Project (as contemplated in the *West Moberly case)*, it is BC Hydro's position that future industrial development in the region cannot be directly attributable to the Project and related impacts, and therefore cannot be considered in evaluating the impact of the Project:

> "The construction of the proposed transmission line will not be a determining factor in connection with other development of Montney shale gas…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 the 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." (Exhibit B-6, WMFN 1.6.1)

Accordingly, BC Hydro is of the view that the impacts from future gas field development in the region should not be considered as a Project-related impact. (Exhibit B-6, WMFN1.6.1)

9.3.1.2.3 West Moberly First Nation's View of Project Impacts

WMFN disagrees with BC Hydro's characterization of the impact of the Project as low; rather, in WMFN's view, the Project will have a serious impact on its treaty rights. In particular, due to the impacts on wildlife and wildlife habitat (particularly moose), and in light of the existing level of development, as well as foreseeable future development induced by the Project, WMFN characterizes the level of adverse impact on the exercise of their treaty rights as serious. (WMFN Final Submission, pp. 16, 27)

As discussed earlier, WMFN conducted an Impact Assessment Study (IAS) which was completed in July 2012, to identify the impacts of the Project on the exercise of their treaty rights.
(Exhibit C5-20) The IAS reports that the impacts of the Project include:

- Adverse impacts on fish and fish bearing streams and creeks, particularly to bull trout at the proposed river crossing;
- Irreversible impacts on wildlife, particularly ungulates, due to habitat destruction and fragmentation, as well as increased access from hunters and predators due to widening of ROW corridors;
- Adverse impacts on vegetation as a result of increased invasive species, and the use of pesticides for vegetation management along the transmission corridor;
- Impacts to archaeological and cultural values, specifically to the historic trail system and cultural camps within the Groundbirch area;
- Adverse impacts on the exercise of treaty rights due to a reduction of an available land base; and
- Adverse impacts to a “meaningful” right to hunt as a result of hunting limitations during construction and the potential decline in moose population.

The impact to the meaningful right to hunt is of particular concern to WMFN, who disagree with the conclusions of AMEC’s Moose Study that the impact to moose will be non-significant. WMFN’s IAS shows that the total remaining moose habitat within the Project Area is down to 13.8 percent of the total moose habitat that could exist. (Exhibit C5-20, pp. 125, 125, Appendix 1, pp. 176, 177; WMFN Final Submission, p. 49) WMFN submits the most recent inventory of moose was conducted in 2004, and the moose data is therefore out of date and unreliable. (Exhibit C5-20, p. 126) In Oral Testimony, Chief Willson of the WMFN reported that WMFN members found that during a severe winter in 2008 the moose population was significantly affected and an estimated 70 percent of moose died in some areas. (T1:450-451) Mr. Slaney, the Environment Manager for AMEC’s Vancouver Environment unit, with responsibility for the EAO, testified that he had heard similar accounts of a bad winter affecting the moose population. (T2:629-630)

WMFN’s IAS contains a series of interviews with community members which contend that the creation of new corridors or the widening of existing ones will increase elk and deer populations, and increase access by hunters, poachers, and predators, which will cause a decline in moose populations or push them further away. (Exhibit C5-20, p. 74; T1: 424, 430) This will, in turn, limit WMFN’s meaningful right to hunt.

WMFN community members are quoted as saying:

> "It seems like we are being pushed more into the mountains. And with all this industrial activity happening, the access it is creating into more and remote places for the harvesting of natural resources, we find ourselves having to go further and further from our community to find – what it is we are looking for. Good healthy animals. We are also finding it – the population of the animals is also depleting." (Exhibit C5-20, p. 72)

> "More land being cleared that is why there is more elk. Years ago, we've never seen elk like now. There is more. Like no one is really hunting them. More land clear so they are moving in here. Like West Moberly, you go way up, there never used to be elk and now there is. They prefer open areas all the trees are gone. They are more in the open… You have to go in the timber for moose. They have to move away to where the timber is. You want moose you have to go in the bush. Years ago, when we were growing up, there was a lot of bush here. There was moose all over the place. Now they cleared land, you have to go up to find moose. (Exhibit C5-20, p. 74)

During the oral hearing in this proceeding Chief Willson made a presentation titled "A Critical Balance" that illustrated the degree of industrial development from multiple industries in their treaty territory and the associated adverse impacts on the land and resources. (Exhibit C5-22, T1:477-496). During the presentation Chief Willson explained the effects of this development as:

> "You can't just keep telling us to go somewhere else, because as you've seen in the maps, we are getting to the point where there is no other place to go. We are completely surrounded now, and we are just whittling away at what little bit we have left."

He also explained what the critical balance is for WMFN:

> "So I started talking about this critical balance, because the balance – being First Nations, we live in two worlds. We live in the modern world, where we have to sit here and use laptops and stuff like that, but also in a traditional sense of culture and values of being able to teach my son how to hunt and what the value of hunting is...We all realize that there is going to be development and with those developments there's going to be impacts that are happening. It's the unnecessary impacts that we're concerned about, and how much of the impacts are happening all at once in northeastern British Columbia." (T1:468-9)

In WMFN's IAS, one community member expresses his concern with decisions made without the context of cumulative and future impacts as "death [by] a thousand decisions I like to think. It is another decision, another piece of land." (Exhibit C5-20, p. 102)

WMFN submits that when understood in the context of these historical impacts and cumulative effects the Project's impacts are more serious. (WMFN Final Submission, pp. 23-24)

WMFN contends "there is little useful land left in WMFN's traditional territory on which to meaningfully exercise treaty rights to hunt, trap and fish or select land for Treaty Land Entitlement ("TLE") settlement" because much of WMFN's treaty territory is already criss-crossed by BC Hydro infrastructure, as well as other industrial developments. (WMFN Final Submission, p. 24)

WMFN submits that since 80 percent of the Project is on private land, this indicates that 80 percent of the Project footprint has already been alienated, and only 20 percent of the proposed footprint remains available for the exercise of treaty rights. WMFN contends that any additional reduction in the available land base is more significant in light of this existing state of affairs. In particular, the Crown lands around the Pine River area have been selected for Treaty Land Entitlement settlement, and are crucial to the stability of WMFN's seasonal round. (WMFN Final Submission, p. 25)

In addition, WMFN contends that the Project will give rise to future development in the region, particularly natural gas developers which will "tie-in" to the transmission line, and whose operation will induce further industrial impacts to WMFN's treaty rights. (WMFN Final Submission, p. 26)

Commission Determination

The Commission Panel finds that the impacts of the Project on WMFN's treaty rights are medium.

BC Hydro and WMFN clearly differ in their views on the level of impact from the Project but both parties agree that there will be new impacts from this project on vegetation, wetland habitat, and wildlife, most notably impacts to moose habitat and increased access to moose by predators and hunters. As well, the Project will require the take-up of undisturbed Crown land.

The Commission Panel accepts that these new impacts will occur as a result of the Project.

These impacts are new, adverse impacts attributable to the Project and the Panel therefore finds that this case can be distinguished from *Rio Tinto Alcan*, as explained in *West Moberly* at paragraph 116. Accordingly, the principles set out in *West Moberly* apply, namely "the historical context is essential to a proper understanding of the seriousness of the potential impacts on the petitioners' treaty right to hunt." (*West Moberly*, para. 117) The Commission understands cumulative impact to mean that whenever there are new impacts from a Project, the Crown must consider the historical context of past impacts, to put the new impacts in proper context and fully comprehend their magnitude.

The Panel accepts WMFN's evidence that the availability of land on which they can exercise their treaty rights has been diminished over time, to some degree. Regarding the moose population specifically, the Panel accepts the evidence from WMFN's community members and Chief Willson, and corroborated by Mr. Slaney, that the moose population had suffered in a recent winter. Thus, using a cumulative impact perspective, the new impacts from this Project must be assessed in the context that the availability of land is diminished and the moose population is depleted from previous numbers.

Mr. Slaney's evidence was that the historical context was considered to some extent but that AMEC was not particularly trying to document that change over time. Given that the historical context does not appear to have been integral in the assessment of the environmental impacts, in determining that the new impacts of the Project are low, the Commission Panel does not find that BC Hydro adequately took the historical context into consideration when assessing the new impacts of the Project. In fact, for the assessment of the impacts to moose, BC Hydro accepted an assessment based on moose population numbers from 2004 which, given the evidence of the bad winter in 2008, cannot be accepted to be accurate.

Given the reasoning above, the Panel cannot find that the new impacts of this Project are low.

At the same time, the Panel also finds that the impacts cannot be characterized as high. There is no evidence to suggest that the impacts of the Project are so severe that they are non-compensable (as described in *Haida Nation*, para. 44 and referenced in Section 9.4.1.2.1 of this Decision). For example, though the moose population will be impacted by the Project, the evidence does not indicate that the population is already so threatened that the Project will extirpate the moose population in the Project Area. As well, as part of this Project, an existing transmission line will be decommissioned and removed. Therefore the Panel places the degree of impact of the Project between low and high, characterizing it as medium.

As indicated above, since there is no strength of claim assessment because WMFN has established treaty rights, the scope of the duty to consult is proportional to the impact of the Project on treaty rights. **The Commission Panel has determined that the scope of the impact of the Project on WMFN is medium on the *Haida* spectrum and therefore the Panel finds that BC Hydro has a medium duty to consult.**

9.3.2 Did BC Hydro Fulfill this Duty?

A medium duty to consult has not been expressly defined in the case law but clearly lies somewhere between the low and high ends of the *Haida* spectrum. A low duty to consult may require giving notice, disclosing information to the First Nation, and discussing issues raised. A high duty to consult may involve deep consultation aimed at finding a solution, providing opportunity to make submissions, allowing First Nations formal participation in decision-making and showing that First Nations' concerns were considered and influenced the decision. (*Haida Nation,* paras. 43-45) While a medium duty consult has not been expressly defined in law, in *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director),* 2004 SCC 74 *(Taku River)*, the Court found that First Nation was owed consultation at a level deeper than minimum consultation, including a level of responsiveness to concerns that can be characterized as accommodation (para. 32).

BC Hydro and WMFN met on a total of eight occasions between June 2010 and June 2012. Exhibit B-22; Exhibit B-32) In between these meetings BC Hydro exchanged numerous correspondence with WMFN. All meetings and correspondence between BC Hydro and WMFN were documented by BC Hydro in its detailed consultation log that was submitted as confidential exhibits in this proceeding. (Confidential Exhibits B-6-1, B-33) The subject matter of these meetings is addressed below in relation to specific complaints about the consultation process.

BC Hydro submits that, despite assessing the scope of the duty to consult with First Nations as low:

> "BC Hydro has engaged in medium level of consultation with Blueberry River, West Moberly, McLeod Lake and Saulteau First Nations by providing notification and making presentations about the Project, engaging in meetings, providing capacity funding where requested, inviting the First Nations to participate in the AMEC environmental overview assessment field surveys, sharing the results of those studies, and continuing to provide updates on the progress of the Project." (Exhibit B-1, p. 6-14)

It is WMFN's view that BC Hydro failed to consult meaningfully, that their conduct displayed bad faith, and that consultation was therefore inadequate.

Both WMFN and BC Hydro have complaints about the other party's conduct in the consultation process; the major complaints are addressed in the following sections.

9.3.2.1 Consultation on Project Alternatives

WMFN contends that BC Hydro failed to consult WMFN on project alternatives, and that BC Hydro should have consulted WMFN at the planning and conceptual stage. (WMFN Final Submission, pp. 16, 20)

WMFN also takes issue with the fact that before engaging WMFN, BC Hydro had already determined that there was going to be a transmission line and submits that BC Hydro was not willing to receive input on any of the alternatives throughout the consultation process. (WMFN Final Submission, pp. 38-42)

BC Hydro contends that it notified WMFN of the Project early in the process. (BC Hydro's Final Submission, p. 42)

The evidence in this proceeding shows BC Hydro's decision-making timeline for the Project. On July 13, 2009 the Commission issued Order G-87-09 which approved $3.0 million in the Definition Phase, for the British Columbia Transmission Corporation (BCTC) to "complete preliminary environmental, engineering and consultation work to reinforce the system in the Dawson Creek area." (Exhibit B-5, BCUC 1.3.2; Exhibit B-14, BCUC 2.26.1) The final approval for that funding was given by the BCTC Board of Directors in November 2009.

BC Hydro submits that between November 2009 when final funding was approved and March 2010 when WMFN was contacted, "the project team was assembled and engineering and environmental service providers engaged. The project team fully commenced Definition Phase work in January 2010, including planning the consultation for the Project." (Exhibit B-14, BCUC 2.26.2)

BC Hydro first notified WMFN of the Project by letter, dated March 3, 2010, which included information about the Project and provided contact information if WMFN had further questions. The letter listed three alternatives BC Hydro (then BCTC) was then evaluating and states "BCTC is currently investigating alternatives for increasing electricity supply to the Dawson Creek area" and "[o]ther Project alternatives may also be identified as BCTC continues to study available options. In addition, transmission line routing will be evaluated following selection of the preferred Project alternative." (Exhibit B-1, Appendix G, pp. 10-11)

BC Hydro first met with WMFN on June 3, 2010 and presented a slide presentation that included the same three alternatives included in the March 3, 2010 letter. (Exhibit B-36)

In her oral testimony Ms. Dutka, BC Hydro's Project Manager for the DCAT Project, submitted that BCTC presented only the options it was seriously contemplating to WMFN in June 2010 and did not discuss any of the dismissed alternatives with WMFN because they were deemed unfeasible. (T2:616-7)

BC Hydro submits that “the law is clear that consultation is only required on those options that are seriously contemplated” and that “there is no point in engaging First Nations in consultations with alternatives that are non-feasible in the sense that they do not serve the Crown’s other objectives.” (BC Hydro Reply Submission, p. 20)

WMFN submits that BC Hydro did not set out its methodology for how it determined alternatives were unfeasible, and contends that WMFN should have had an opportunity to give input into selecting feasible project alternatives. (WMFN Final Submission, p. 40)

9.3.2.2 Conducting and Sharing a Preliminary Assessment of Impacts

WMFN submits that the Crown must conduct a preliminary assessment of the Project impacts and the scope of consultation at the outset of Project. (WMFN Final Submission, p. 33) WMFN further submits that the law is clear that the Crown must provide that preliminary assessment to the affected First Nation, and provide an opportunity for the First Nation to give feedback. WMFN refers to *Adams Lake Indian Band v. British Columbia,* 2011 BCSC 266 *(Adams Lake)*:

> “The Crown is obliged to make a preliminary assessment of the strength of the claim and the potential impact of the proposed decision on the asserted rights. The Crown’s obligations also extend to providing the affected aboriginal group with an opportunity to comment on these preliminary assessments.” (para. 131)

WMFN also submits that the recent *West Moberly* case supports a timely provision of the preliminary assessment to the affected First Nation. In its Final Submission WMFN explains:

> “In West Moberly, the BC Court of Appeal determined that the Crown’s refusal to provide a timely preliminary assessment, in conjunction with providing “standard referral letters” to constitute an unreasonable consultation process in response to WMFN’s concerns.” (WMFN Final Submission, p. 34, referencing West Moberly, paras. 152, 219)

In WMFN’s view “BC Hydro failed to conduct a proper preliminary assessment about the potential adverse impacts on WMFN’s rights from the proposed DCAT project, share that assessment with WMFN and consult with WMFN on the same.” (WMFN Final Submission, p. 28)

BC Hydro, on the other hand, submits that the Crown has no legal obligation to share its preliminary impact assessments. (BC Hydro Final Submission, p. 32) Nevertheless, BC Hydro contends that it did share its preliminary assessment of impacts with WMFN "as soon as the studies upon which it was based were concluded" and on July 12, 2011 through the filing of the CPCN application. (BC Hydro Reply Submission, p. 21, BC Hydro Final Submission, p. 30) BC Hydro submits that because it accepted that WMFN had treaty rights in the area, and therefore did not conduct a strength of claim assessment, BC Hydro's preliminary assessment was limited to an assessment of the impacts on those treaty rights. (BC Hydro Final Submission, p. 30) BC Hydro's preliminary assessment of the seriousness of the impact was that any impact to WMFN's treaty rights would be low.

According to WMFN, BC Hydro should have shared this preliminary assessment with them much earlier in the consultation process, rather than upon the filing of the CPCN application one year after consultation was initiated.

9.3.2.3 Consultation on Impacts and Negotiating the Terms of a Study

WMFN submits that "BC Hydro failed to engage in a meaningful dialogue or substantive consultation with WMFN on...the nature and scope of its rights and potential impacts of the proposed DCAT Project on those rights." (WMFN Final Submission, p. 57)

"BC Hydro contends that it has made numerous attempts to engage with WMFN over the past two years but that notwithstanding these efforts WMFN has only recently identified the specific potential impacts on WMFN's rights from the DCAT Project." (BC Hydro's Final Submission, p. 26)

WMFN states that in order for WMFN to identify the potential impacts of the Project on their treaty rights, it first had to conduct a community based impact assessment study:

> "WMFN was not in a position to provide specific information regarding potential adverse effects on its Treaty rights – the very information requested by BC Hydro – until it could complete the IAS. The fact that BC Hydro seems to have expected this information to be provided prior to completion of the IAS indicates its fundamental misunderstanding of the importance of this Study to the

> assessment of potential adverse impacts and to the consultation process as a whole. Repeated requests for information that WMFN was not in a position to give until completion of the Study do not constitute adequate consultation." (WMFN Final Submission, p. 28)

BC Hydro states that since the initial meeting in June 2010, it has worked with WMFN to address WMFN's request to conduct a study and that the delays in reaching an agreement can be attributed to WMFN, who changed its position, having originally proposed a TUS but later choosing to pursue an impacts study. BC Hydro submits that it "was flexible in the type of study WMFN wanted to pursue provided its scope was appropriate given the size and nature of the DCAT Project." (BC Hydro Final Submission, p. 35) BC Hydro submits that it was in July 2011 that WMFN requested an impact study rather than a traditional use study. (T2:587)

WMFN submits that it did not alter its position as WMFN had not initially proposed a TUS; rather BC Hydro had initially suggested a TUS, but WMFN had communicated its desire to conduct an impact study with its submission of the proposal in October 2010. (WMFN Final Submission, pp. 9, 44, 45) WMFN also submits that BC Hydro (in June 2011) attempted to "piggyback" data collection for the DCAT Project on a study for the Site C project. (WMFN Final Submission, p. 58)

From WMFN's perspective, WMFN made it clear to BC Hydro that the impacts of the Project could be potentially specific, but also incremental and cumulative in nature which requires more than a site-specific TUS along the transmission line. WMFN wanted a study that considered the potential cumulative impacts of the Project, as well as a larger study area than just the reference route. WMFN stated:

> "Through multiple versions and over a series of months, BC Hydro worked to reduce the scope of WMFN's proposed DCAT work so that it would conform to a more narrow set of specific expectations on the part of BC Hydro." (Exhibit C5-8, 2.0)

BC Hydro's position was that the scope of the study should be limited to the DCAT Project and should not be concerned with the cumulative impacts of historic development in the area. (Confidential Exhibit B-17-1, BCUC 2.2.2)

The evidentiary record relied upon by the submissions above are included in a confidential exhibit and are only paraphrased or summarized in this paragraph. The record shows that BC Hydro sent WMFN a draft Terms of Reference (ToR) for a study on September 10, 2010. The parties met on October 22, 2010 to discuss the ToR, and prior to that meeting WMFN sent BC Hydro a proposal for a community-based impact study by UNBC Professor Wendy Aasen. Between October and February 8, 2010 there was a series of communications between the parties, which included revisions to the ToR of the study. On December 17, 2010, BC Hydro provided a revised ToR, which reflected the parties discussions about limiting the scope of the study. On February 8, 2011, the parties met again to further discuss the study. Between March and May 2011, WMFN and BC Hydro exchanged budget proposals. In June 2011, BC Hydro suggested that the proposed DCAT study be combined with a study for the Site C Project. (paraphrased from Exhibit B-14-3, Confidential Attachment 5, pp. 45-437)

BC Hydro filed its CPCN application for the Project in July 2011.

On November 9, 2011 WMFN applied to BCUC for an adjournment of the Project proceedings “until such time as a study outlining the impacts of BC Hydro’s proposed DCAT Project on WMFN is completed.” (Exhibit C5-13, p. 1) BC Hydro opposed the adjournment, stating that:

> “BC Hydro has consistently been willing to fund and support a WMFN study provided it is appropriate to the DCAT Project. It has engaged significant time and money to reach a mutual agreed upon TOR and budget for such a study, but unfortunately no agreement has been reached.” (Exhibit B-18, p. 6)

The BCUC granted the adjournment of the CPCN Proceeding, and the parties continued to negotiate the terms of a proposed impact assessment study. They finally reached an agreement in principle in November 2011 and the final agreement was signed in February 2012. (WMFN Final Submission, p. 14) A draft of the IAS was provided to BC Hydro in June 2012 and the final study was completed in July 2012 and submitted in this proceeding. (Exhibit C5-20)

BC Hydro submits that the there was substantive information included in the final report that was not included in the draft report. (T2:662)

WMFN's replies that there was no agreement to provide all information in the draft report that was to be included in the final report. (WMFN Final Submission, p. 46)

In oral testimony, WMFN explained some of the process it had to follow to create the IAS. WMFN explained that in the First Nation knowledge is held by specific individuals and that a study such as the IAS can only be released after following community protocols and a community verification process. (T1:379-384)

Notwithstanding the proposed study, BC Hydro submits that it invited WMFN's feedback and input on many occasions, before and after the filing of the CPCN application. Examples of information on which input was sought include:

- Information regarding the alternatives (June 3, 2010);
- Segment maps showing the initial route options (November 12, 2010);
- Evaluation summaries and proposed preferred route segment maps (January 18, 2011);
- The draft EOA (March 10, 2011);
- The proposed Field Programs (July 12, 2010 and April 21, 2011);
- The CPCN Application (July 12 and 14, 2011);
- Various Project updates;
- Information regarding the updated route alignment (February 6, 2012);
- The draft Archaeological Impact Assessment (AIA) (February 6, 2012); and
- The draft Construction Environmental Management Plan (May 8, 2012).

(BC Hydro Final Submission, pp. 33-34)

BC Hydro contends that despite these numerous requests for feedback, WMFN provided no response. (BC Hydro Final Submission, pp. 33-34)

WMFN submits that they could not provide feedback until it properly understood the impacts of the Project on their treaty rights. In WMFN's view, only once they completed the IAS could they engage in discussions about mitigation, which would be the next step in consultation (T1:429; T2:549) WMFN submits:

> "BC Hydro failed to seriously consider the concerns raised by WMFN and WMFN's Impact assessment Study…including specific concerns raised about cumulative effects, impacts on moose populations in the area, and the development implications of the proposed DCAT Project, such as the future web of transmission lines that will be tied in to the DCAT should it proceed." (WMFN Final Submission, p. 28)

During the Oral Hearing BC Hydro submitted that, having just received the final IAS, they had not yet had time to fully consider the impacts identified therein.

> MS. DUTKA: A: So I think at this point we don't know enough about the seasonal round to fully understand how DCAT may potentially impact it. However, we are definitely interested in and willing to meet with West Moberly First Nation to determine the specifics, including perhaps timing, locations and the nature of any activities that may occur in order to determine what those potential impacts are. Once we know these specifics, we can work with West Moberly First Nation to determine the best way to avoid or mitigate them, as much as practical. This could involve modifying construction activity timing, perhaps establishing work avoidance zones, that sort of thing. (T2:575)

According to WMFN, BC Hydro has failed to give serious consideration to WMFN's concerns, including those raised in and as a result of the IAS. These concerns include potential adverse impacts on the following: moose populations, Treaty Land Entitlement selections, historical trails and seasonal rounds, and the Pine River crossing. (WMFN Final Submission, p. 43)

BC Hydro's position is:

> "With respect to potential impacts to WMFN's seasonal round and historical trails, the evidence on record is that while WMFN has yet to provide sufficient detailed information about location and in the case of the historical trails, current use, BC Hydro is interested in meeting with WMFN to obtain these specific details. If once these specifics are known to BC Hydro it appears there is potential for impacts, BC Hydro can consider mitigation and avoidance measures during construction and operations including modifying construction activity,

> timing, establishing work avoidance zones, and shifting poles." (BC Hydro's Final Submission, pp. 37-38)

During the oral hearing, Chief Willson agreed that the IAS report provides a good basis for further consultation because WMFN is now better informed. (T2:549) He stated:

> "Now that we've got the report, we know basically who we need to talk to about it. Once things are in place, the process can move real quick." (T2:552)

BC Hydro maintains that it continues to be open to making micro-routing changes to accommodate and mitigate impacts. In response to WMFN's concerns regarding the Pine River crossing, BC Hydro also looked into drilling under the river; however, BC Hydro's technical staff found that this was not a feasible option due to large technical risks as well as costs. BC Hydro submits that they have designed the Pine River crossing to minimize impacts on WMFN's treaty rights, since the crossing will simply replace the currently existing crossing. (BC Hydro Final Submission, p. 38)

9.3.2.4 The EOA and Concern about Moose

The consultation log shows that WMFN raised concerns about wildlife and especially moose as early as the first meeting with BC Hydro on June 3, 2010. (Exhibit B-6-1, WMFN 1.7.1, Confidential Attachment 1, p. 2) In conducting the EAO, BC Hydro did not consult WMFN on the selection of the VECs in general (T2:680) and moose was not included as a VEC although wetland habitat was. BC Hydro shared the completed draft EAO with WMFN on March 10, 2011. WMFN later expressed concern that BC Hydro's EOA study did not include moose as a VEC, despite its cultural importance to WMFN. WMFN submits that they raised their concern about moose with BC Hydro again at the June 22, 2012 meeting between the parties and that BC Hydro proceeded to do a desktop study of moose without notifying WMFN, or seeking their input into the study. (WMFN Final Submission, pp. 47-50)

BC Hydro submits:

> "moose were adequately considered in the initial EOA through the identification of wetlands as a Valued Ecosystem Component. While the parties dispute whether this adequately addressed potential impacts to moose from the DCAT

> project, this dispute is irrelevant given the additional study undertaken by AMEC prior to the oral hearing (the "Moose Study")." (BC Hydro Final Submission, p. 37)

9.3.2.5 Concern about Future Tie-ins

WMFN also contends that BC Hydro failed to adequately consult WMFN regarding the "spider-web" of future tie-ins as a result of the DCAT Project. Chief Willson, in his oral testimony, questioned where these tie-ins would be and whether they would run on existing development or would newly disturb land. (T2:559)

BC Hydro maintains:

> "Electrification is not a cause of development but rather a piece of infrastructure that needs to be developed in response to development. Whether those developments will be undertaken in a way that has an adverse impact on First nations is beyond BC Hydro's knowledge or control and BC Hydro cannot consult meaningfully with respect to them." (BC Hydro Reply Submission, p. 23)

9.3.2.6 Commitment to the Consultation Process

In BC Hydro's view, WMFN has not shown the same commitment as BC Hydro, to consultation between the parties. In other words, it would seem that BC Hydro believe that WMFN has not been reciprocally engaged in consultation with BC Hydro. BC Hydro refers to the period between July 19, 2011 and November 25, 2011 when it made numerous attempts to schedule and reschedule a meeting with WMFN. (BC Hydro Final Submission, p. 34)

WMFN suggests that the consultation record does not support BC Hydro's interpretation that WMFN was not committed to engaging with BC Hydro. WMFN states that delays in scheduling meetings were a result of various circumstances, including, but not limited: to the practice of traditional activities; unforeseen events in the community; and, time and capacity challenges due to the unprecedented volume of consultations and negotiations in which WMFN is engaged. WMFN submits that it advised BC Hydro of these challenges, and continued its best efforts to schedule with BC Hydro. (WMFN Final Submission, pp. 30-32)

9.3.2.7 Consultation Completeness

BC Hydro submits that it is committed to continuing the consultation process with WMFN even after the CPCN is issued, acknowledging that consultation is required at every stage of the Project, including construction and operation. Throughout their oral testimony, BC Hydro's panel communicated that they recognize a need to meet with WMFN and discuss the specific impacts indicated in the IAS. (T2:575) However, BC Hydro contends that consultation does not need to be complete before the BCUC issues a CPCN. (BC Hydro Final Submission, p. 42)

WMFN disagrees with BC Hydro that the Commission does not need to be persuaded that all consultation is complete, stating that this is an error in law. WMFN, citing *Mikisew* (at para. 67) explains:

> "While it is true that implementation of the appropriate accommodation measures is (or should be) ongoing, and it is equally true that further consultation must occur as a project advances through various stages, it is incontrovertibly clear at law that consultation must occur <u>prior</u> to the making of the relevant decision, in this case the issuance of the CPCN. Otherwise, meaningful consultation cannot take place." (WMFN Final Submission, p. 29)

BC Hydro also submits that in its view the consultation process was not procedurally flawed, and if any procedural inadequacies exist, they are overcome because the ultimate objectives of consultation have been met. (BC Hydro Reply Submission, p. 18)

BC Hydro submits that WMFN has not identified any showstoppers or other issues that cannot be dealt with over the next few months. (BC Hydro Final Submission, p. 26)

In sum, BC Hydro submits that the consultation record shows that consultation with WMFN has been reasonable and adequate to the close of the evidentiary phase of the proceeding.

WMFN submits that consultation to date has not been meaningful or in good faith, and is, therefore, inadequate.

Commission Determination

The Commission Panel finds consultation with WMFN on the DCAT Project is inadequate to the date of this Decision because BC Hydro has not yet obtained adequate knowledge of the potential impacts of the Project on WMFN's treaty rights nor consulted the WMFN on those impacts. The Panel bases this determination on the following:

- BC Hydro acknowledges that it currently does not know enough about the seasonal round and how the DCAT Project may impact it;
- The issue of moose and moose habitat and the mitigation of potential impacts on these, has not been adequately assessed; and
- BC Hydro did not consider the new adverse impacts of the Project with an adequate cumulative impact perspective.

To elaborate on each of these points, BC Hydro stated multiple times in oral testimony that WMFN's IAS provided new information on the seasonal round, and that BC Hydro did not know enough about the seasonal round or how the DCAT Project may potentially impact it. The seasonal round is the practice of WMFN's treaty rights of hunting, fishing and trapping. The Courts in *Mikisew* have established that consultation on treaty rights must address the impact of a contemplated activity on treaty rights and that the Crown must communicate its findings to the First Nation. Therefore, given that BC Hydro has admitted that they do not know the impacts the DCAT Project will have on WMFN's seasonal round, which is the exercise of treaty rights, consultation cannot be adequate. BC Hydro did assess the impact of the Project on the activities of hunting, trapping and fishing separately as low but in making that assessment, it did not have knowledge of how WMFN exercises those rights in the seasonal round.

In BC Hydro's view the delays in coming to an agreement and completing the IAS are due to WMFN. In WMFN's view BC Hydro repeatedly tried to narrow the scope of the study due to a failure on BC Hydro's part to understand that looking at the cumulative impacts in the region are necessary to fully comprehend the seriousness of the impacts of the Project itself. Regardless of what caused the delay in reaching the agreement, the fact is that both parties agreed to have a completed IAS in

July 2012. While the Panel recognizes BC Hydro's frustration expressed in its view that the information in the draft IAS submitted in June 2012 was incomplete and was not sufficient for BC Hydro to identify some potential impacts specific to the DCAT Project, the fact remains that the final IAS was agreed upon by both parties and BC Hydro therefore accepted that the final information from WMFN would be available to it in July 2012.

Regarding the issue of moose and moose habitat, and the mitigation of impacts on these, the Commission finds that WMFN raised moose as an issue of concern and one it wished to be studied early in the consultation process. Despite this, BC Hydro's EAO did not include moose in its list of wildlife until an error was realized and a replacement list was submitted at the oral hearing. Even then, moose itself was not included as a VEC in the study and while wetland habitat was, it seems likely that the consultation process would have been more meaningful for WMFN if BC Hydro had consulted the WMFN on which VECs and VSCs to include in the environmental study.

BC Hydro contracted for the Moose Study which was completed in July 2012 and submitted as part of the evidentiary update in this proceeding on July 6, 2012. This study was not shared with WMFN before it was submitted through the Commission process. While BC Hydro submits that any dispute over whether the parties adequately addressed potential impacts to moose is irrelevant given that the Moose Study has now been completed, the fact that the Moose Study and its findings has not yet been discussed with the WMFN is a flaw in consultation. Moose are clearly an important species to WMFN on which they exercise their treaty right to hunt. The Crown is thus obliged to inform itself of the potential impacts on this right and communicate those findings to WMFN. The Commission Panel cannot accept that submitting a study late in this proceeding, without discussing it with WMFN, is communication that constitutes meaningful consultation in this case. It is responsive to WMFN's concerns but the opportunity to actually consult on the findings was missed.

Finally, the Commission Panel finds that BC Hydro did not consider the new impacts of the Project with an adequate cumulative impact perspective. The law in *Rio Tinto Alcan* is clear, consultation is on the new impacts of a Project.

The Panel recognizes that the *West Moberly* decision was issued in late 2011, after consultation with WMFN had already begun, but that decision clarifies the law such that in this case, the historical context or cumulative impacts should be considered when assessing the new impacts of the Project. The evidence of BC Hydro and the methodology used in the EAO, do not suggest that cumulative impacts were considered to the degree directed by *West Moberly*. The WMFN view on the fragmentation of land and resulting potential impacts on wildlife is now available from the IAS and the Panel accepts WMFN's position that it is now in a position to consult on these issues. The Panel expects this consultation will include the issue of potential impacts on wildlife corridors.

Regarding future impacts, the Commission Panel is intrigued by the evolving law that new impacts of a Project may be informed by potential direct, future impacts, but given that this Decision does not turn on this issue, the Panel takes no position on this matter at this time.

The evidence of Chief Willson is that the IAS, that is now complete, provides a good basis for consultation and that now that the IAS is in place, consultation could proceed quickly. The Commission Panel is therefore not convinced that a cumulative impact assessment must be completed at this point.

The Commission Panel recognizes that its role is to assess consultation to the point of the CPCN decision and that consultation will necessarily be ongoing after that decision until the Project is complete, and that BC Hydro is committed to ongoing consultation with First Nations until the same time. However, in this case, given that treaty rights are established and that the impacts on those rights are the very subject of consultation as established by the Courts, the Commission cannot determine consultation has been adequate at this point when the impacts of the Project are unknown or have not been adequately assessed.

The Panel dismisses the notion that either party acted in bad faith during consultation. The Panel recognizes that BC Hydro has been responsive to concerns raised throughout the process. The Panel also accepts WMFN's evidence that the practice of traditional activities, unforeseen events in the community, and time and capacity challenges caused delays in meeting and the Panel does not interpret WMFN's lack of response to BC Hydro's specific invitations as bad faith. Rather, the

Commission Panel finds that consultation between the two parties seems to have suffered from a lack of understanding between the two sides. It appears that the two parties' communication was lost in translation with each side meeting and communicating but not truly understanding the other party. The Commission Panel also recognizes that WMFN had to follow community protocols and a community verification process to prepare their IAS and that these protocols and processes can take time but must be respected.

The issue facing the Panel is that BC Hydro, at this point, does not have adequate information and understanding of the potential new impacts that the Project may have on WMFN's treaty rights. **Accordingly, the Commission Panel directs BC Hydro to provide the Commission with evidence of further consultation no later than 180 days from the issuance of this Order.** The Commission Panel recognizes that as Chief Willson has indicated, the consultation process may run more quickly from this point and the Panel encourages BC Hydro to submit further evidence at the earliest point it can. The Commission will ensure that if a hearing is required at that time it will proceed in a timely manner so as not to unduly delay the Project. **The Commission Panel expects the further evidence will demonstrate consultation to a medium level on the *Haida* spectrum, addressing the deficiencies outlined in this Decision. The Commission also expects that this evidence will reveal any mitigation necessary respecting potential impacts.**

Regarding the timing of the start of consultation, the Panel finds it reasonable that BC Hydro (then BCTC) was approved for final funding for the definition phase of the Project in November 2009 and then contacted WMFN in March 2010. The case law has established that the Crown must consult First Nations at an early stage and on strategic level decisions (*Haida Nation*, para. 76) and that consultation "must take place when the project is being defined and continue until the project is complete." (*Kwikwetlem*, para. 70) Although BC Hydro must have first contemplated activity to reinforce the system in the Dawson Creek area prior to its request for definition phase funding in July 2009, the time period of November 2009 to March 2010 seems reasonable to have final funding approved and to prepare for and begin consultation in this case.

Regarding consultation on alternatives, the Panel finds that BC Hydro presented alternatives to WMFN at the outset of consultation. The March 3, 2010 introductory letter on the Project states: "[o]ther Project alternatives may also be identified as BCTC continues to study available options" and lists three alternatives. This evidence shows that alternatives to the Project were the subject of consultation at the outset. The Commission Panel finds it reasonable that BC Hydro present WMFN with the alternatives it finds feasible. BC Hydro remains the Project decision maker but must consult First Nations to understand the potential impacts of the Project, and then balance this information, with other considerations (economic, societal and more) and make its Project decisions. Given this, it is not practical to have the company present options to WMFN that the company could not feasibly build or operate.

Regarding sharing of preliminary assessments of impacts, the law is clear that the Crown's knowledge of impacts must be communicated to First Nations as shown in *Mikisew*. While there may be no express legal obligation to share the "preliminary assessment of impacts", the information must be shared at some point. The Commission finds BC Hydro's submission that its preliminary view of impacts was made known when the environmental studies were completed, as reasonable timing. Therefore, regardless of the dispute over the legal obligation to share the preliminary assessment, the Commission finds that in sharing the draft EOA with WMFN and seeking WMFN's feedback, BC Hydro did share its preliminary assessment in a relatively timely manner.

When considering further consultation, the Panel is informed by Mr. Justice Finch, in the *West Moberly* case, where he considered the issue of prescribing a consultation process, and states: "…it is preferable, in this case, that the specific direction be set aside so that the parties may resume consultation as indicated, and unfettered."

In this regard, the Commission Panel has not hesitated to pass judgment on whether BC Hydro has consulted adequately. However, the Panel is reluctant to provide a recipe for how BC Hydro and WMFN ought to enter into their negotiation and consultation process. It is important to note each issue in and of its self may not have been sufficient to lead the Panel to a conclusion that consultation is inadequate. This determination of inadequate consultation is a result of a consideration of all of the related evidence and a combination of the identified deficiencies.

9.4 BC Hydro's Consultation with Other Aboriginal Peoples

9.4.1 Other Treaty 8 First Nations

This section considers consultation with the remaining BC Treaty 8 First Nations: McLeod Lake, Saulteau, Blueberry River, Halfway River, Prophet River, Doig River, and Fort Nelson.

McLeod Lake, Saulteau, Blueberry River, Halfway River, Prophet River, Doig River, and Fort Nelson are also signatories of Treaty 8. As such, they share in the Treaty 8 "right to pursue their usual vocations of hunting, trapping and fishing throughout the tract surrendered" although in *Mikisew* the Court clarified that "the "meaningful right to hunt" is not ascertained on a treaty wide basis (all 840,000 square kilometers of it) but in relation to the territories over which a First Nation traditionally hunted, fished and trapped, and continues to do today." (*Mikisew*, para. 48)

BC Hydro's search of the BC provincial government Consultative Area Database (CAD) revealed that McLeod Lake, and Saulteau (in addition to WMFN discussed above) have treaty rights in the Project Area. (Exhibit B-1, p. 6-6; Appendix G, pp. 1-3) BC Hydro also identified Blueberry River as having aboriginal interests in the Project Area. (Exhibit B-1, p. 6-6)

BC Hydro gave McLeod Lake, Saulteau and Blueberry River notification of the Project on March 3, 2010 and provide contact information if the First Nations had questions. Through 2010 to the close of evidence in this proceeding BC Hydro met with McLeod Lake, Saulteau and Blueberry River to discuss the Project. (Exhibit B-1, pp. 6-14-6-24)

BC Hydro states that neither McLeod Lake or Saulteau identified any Aboriginal or treaty rights or traditional uses in the Project area. (Exhibit B-5, BCUC 1.7.3, 1.8.2)

BC Hydro states that it funded Blueberry River to conduct a TUS which was completed in April 2011. BC Hydro submits that, according to the TUS, historical and ethnographic records showed evidence of the use of the Project area by the ancestors of the Blueberry River people but no evidence of contemporary use of the Project Area by Blueberry River members. (Exhibit B-1, p. 6-22)

Regarding the other Treaty 8 First Nations, BC Hydro initially determined that they do not have interests or rights within the Project Area. However, upon learning that two additional BC Treaty 8 First Nations (Prophet River and Doig River) were being consulted with regards to Crown tenure applications within the Project Area, BC Hydro also provided notice of the Project and an opportunity to characterize their rights in the Project Area to each of the other BC Treaty 8 First Nations: Halfway River, Prophet River, Doig River and Fort Nelson. None of these First Nations responded to BC Hydro. (Exhibit B-1, pp. 6-21, 6-22) BC Hydro's view is that there is no further duty to consult these four Treaty 8 First Nations.

BC Hydro first introduced the Project to McLeod Lake on March 3, 2010 by way of a letter and map attachment illustrating the Project and the alternatives under consideration. In addition to ongoing correspondence between the parties since this initial letter, BC Hydro met with McLeod Lake on 5 occasions: May 13, 2010; July 21, 2010; November 3, 2010; February 9, 2011; and August 18, 2011. (Confidential Exhibit B-14-1, BCUC 2.29.1)

McLeod Lake initially indicated that it would require capacity funding to participate in the consultation process. McLeod Lake was to provide a work plan and budget for consultation activities so that BC Hydro could provide funding, however, McLeod Lake did not submit a plan or budget to BC Hydro for their consideration and therefore no capacity funding was provided.

In May and July 2010 BC Hydro made presentations to McLeod Lake about the Project and the alternatives. McLeod Lake was also invited to participate in the field studies conducted by AMEC in the summer of 2010. One McLeod Lake member participated in the aquatics field study, one in the wildlife field study, and one in the archaeology field study. (Exhibit B-5, BCUC 1.13.3)

In January 2011 BC Hydro emailed McLeod Lake the route options being considered and asked McLeod Lake to review them and notify BC Hydro of any concerns. The parties met in February 2011 to discuss the route options. Subsequently, in March 2011, BC Hydro sent McLeod Lake a copy of the draft EAO for comment but BC Hydro did not receive any. (Exhibit B-1, p. 6-22) In April 2011, BC Hydro invited McLeod Lake to participate in additional field studies in the summer of 2011 but McLeod Lake did not respond. (Exhibit B-1, p. 6-22)

On February 6, 2012 BC Hydro sent a letter to McLeod Lake formally advising them of their intent to resume the BCUC proceeding. This letter included a Project update, maps and modifications to the route alignment, and an interim report on the Archeological Impact Assessment. McLeod Lake was invited to provide feedback and comments although the consultation record does not indicate that McLeod Lake responded. (Exhibit B-22, Attachment 2, Appendix A, pp. 12, 13) In addition, BC Hydro provided McLeod Lake with a draft of the Environmental Management Plan. (Exhibit B-34, Attachment 1, p. 4)

BC Hydro states that "the need to identify methods to avoid, mitigate or accommodate specific potential impacts has not arisen" during the consultation with McLeod Lake. (Exhibit B-5, BCUC 1.7.3) However, correspondence and meeting minutes did indicate that McLeod Lake expressed some concern regarding the route alignment and taking up of more Crown lands. BC Hydro submit they took this into consideration when comparing the route options, selecting a route option that would parallel existing transmission lines where possible so that "where the new line is expected to parallel an existing line, the additional ROW width will be less than what is typically required for new transmission line ROW." (Exhibit B-1, p. 6-12)

BC Hydro first introduced the Project to Saulteau on March 3, 2010 by way of a letter and map attachment illustrating the alternatives under consideration. Since this first introduction BC Hydro corresponded with Saulteau periodically to provide information, and set up meetings. BC Hydro met with Saulteau on 8 occasions: June 4, 2010; July 28, 2010; October 22, 2010; December 7, 2010; February 9, 2011; July 28, 2011; August 19, 2011; and October 6, 2011. (Confidential Exhibit B-14-1, BCUC 2.29.1)

In the summer of 2010 BC Hydro offered Saulteau capacity funding; however Saulteau did not take BC Hydro up on its offer.

In June 2010 BC Hydro made a presentation to Saulteau, which provided an overview of the Project as well as information on the alternatives. A second presentation was scheduled for July 2010, however Saulteau did not show up to the scheduled meeting.

Several members of Saulteau participated in AMEC's field studies throughout the summer of 2010. One member participated in the wildlife field study; one in the vegetation field study; and one in an archaeology field study. (Exhibit B-5, BCUC 1.13.3)

In January 2011 BC Hydro sent a binder of materials to Saulteau and met with Saulteau in February 2011. Following this meeting BC Hydro proposed another meeting for March and made several attempts to schedule a date with Saulteau. However, Saulteau was not able to meet with BC Hydro again until the end of July 2011. BC Hydro also sent Saulteau a copy of the EAO for comment, as well as a notice of regulatory filing and a copy of the CPCN application but did not receive any comments. (Exhibit B-1, p. 6-22) BC Hydro also invited Saulteau to a July 20 workshop to review the CPCN Application, and, as Saulteau did not attend the workshop, sent a hardcopy of the materials to Saulteau. In summer 2011 Saulteau members participated in additional AMEC field studies on vegetation and rare plants, aquatics, and archeology. (Exhibit B-5, BCUC 1.13.3)

On February 6, 2012 BC Hydro sent a letter to Saulteau formally advising them of their intent to resume the BCUC proceeding. This letter included a Project update, maps and modifications to the route alignment, an interim report on the Archeological Impact Assessment. Saulteau was invited to provide feedback and comments. (Exhibit B-22, Attachment 2, Appendix A, pp. 16, 17) In addition, BC Hydro provided Saulteau with a draft of the Environmental Management Plan (Exhibit B-34, Attachment 1, p. 4) The consultation record does not indicate that Saulteau provided any comment on either of these documents.

BC Hydro submits that "the need to identify methods to avoid, mitigate or accommodate specific potential impacts has not arisen" during the consultation with Saulteau. (Exhibit B-5, BCUC 1.8.2)

BC Hydro first introduced the Project to Blueberry River First Nation (Blueberry River) on March 3, 2010 by way of a letter and map attachment illustrating the Project and the alternatives under consideration. BC Hydro met with Blueberry River on 6 occasions: May 12, 2010; July 12, 2010; August 19, 2010; October 22, 2010; March 22, 2011; and June 16, 2011. (Confidential Exhibit B-14-1, BCUC 2.29.1) In addition to these meetings BC Hydro had substantive communication with Blueberry River through written and email correspondence.

In May and June, 2010 BC Hydro gave two presentations to Blueberry River to provide an overview of the Project and provide information on the alternatives under consideration. (Exhibit B-5, BCUC 1.1.1)

In November 2010 BC Hydro provided capacity funding to Blueberry River to review project materials, participate in consultation meetings, and conduct a TUS. In March 2011 BC Hydro provided Blueberry River with a draft copy of the EAO for review and comment. (Exhibit B-5, BCUC 1.12.1) The TUS study was prepared for Blueberry River by consultants Bouchard & Kennedy and completed April 18, 2011. BC Hydro provided additional funding in April 2011 upon receipt of the final TUS report and for review of the EAO. The TUS indicates there is no contemporary use of the Project Area by Blueberry River members but did identify two sites of cultural significance to the Nation. BC Hydro informed Blueberry River that the proposed route of the Project does not cross this area but agreed to flag them and assured the Nation that in the event any Project work is identified for this area BC Hydro will conduct an Archaeological Impact Assessment prior to any construction. (Exhibit B-1, p. 6-23; Appendix G, p. 171)

In the summer of 2011 two Blueberry River members participated in archaeological field studies. (Exhibit B-5, BCUC 1.13.3)

On February 6, 2012 BC Hydro sent a letter to Blueberry River formally advising them of their intent to resume the BCUC proceeding. This letter included a Project update, maps and modifications to the route alignment, and an interim report on the Archaeological Impact Assessment. As well, BC Hydro provided Blueberry with a draft Environmental Management Plan. Blueberry River was invited to provide feedback and comments (Exhibit B-22, Attachment 2, Appendix A, pp. 1, 2) but the consultation record does not indicate that Blueberry River gave any comments or feedback in response.

Commission Determination

The Panel finds that BC Hydro's consultation with McLeod Lake, Saulteau, Blueberry River, Halfway River, Prophet River, Doig River, and Fort Nelson has been adequate. In making this determination, the Panel considered that BC Hydro engaged with these First Nations but in all cases, the First Nation either did not engage at all or, at some point, stopped engaging. The Panel finds that BC Hydro appears to have responded to the concerns which were raised by the First Nations as evidenced by the lack of any further response from the First Nations. Therefore, the Panel has determined that the duty to consult has been met.

9.4.2 Métis

In January 2011 BC Hydro sent Métis groups in the Project Area a letter introducing the Project and inviting them to the Project open houses. The letter also directed them to the Project webpage or to contact BC Hydro's stakeholder relations manager for more information. (Exhibit B-5, BCUC 1.16.1) No Métis groups attended the open houses. (Exhibit B-1, p. 6-38)

In April 2011 BC Hydro sent another letter which included a map of the preferred route to Métis Societies. (Exhibit B-5, BCUC 1.16.1)

At the time BC Hydro submitted the CPCN Application to the Commission in July 2011 no Métis community had indicated that its communal rights would be adversely affected by the Project. BC Hydro concluded that it had no obligation to further consult with the Métis. (Exhibit B-5, BCUC 1.16.1)

Commission Determination

The Commission Panel finds that BC Hydro has met its duty to consult the Métis. The Panel is satisfied that the Metis have been adequately informed by BC Hydro about the Project and that the Métis did not engage in consultation.

9.4.3 Kelly Lake Cree Nation

In October 2011 BC Hydro received a letter from the Kelly Lake Cree Nation (KLCN) in which KLCN asserted rights in the Project Area and sought to be consulted. (Exhibit B-22, p. 94) BC Hydro submitted that it "understands that KLCN is one of at least three groups that claim to represent the aboriginal community of Kelly Lake. KLCN is not an Indian band under the Indian Act, nor is it recognized as a First Nation or rights-bearing Métis group by the Province." (Exhibit B-22, p. 94)

BC Hydro sent a response letter to KLCN on February 24, 2012 in which BC Hydro raised the question of KLCN's representative status. However, the letter also provided information about the Project and the review process. In the letter BC Hydro committed to providing KLCN with future updates on the Project and invited KLCN to provide BC Hydro with information about KLCN's history and rights, as well as input on the Project itself. BC Hydro also offered to meet with KLCN. (Exhibit B-22, Appendix A, p. 9)

The evidentiary record does not indicate that KLCN responded to BC Hydro's letter, nor does it indicate that BC Hydro followed up with the KLCN.

Commission Determination

Given the evidence that KLCN is not recognized as a First Nation or under the *Indian Act*, and the lack of evidence to contradict this, the Commission Panel finds it likely that BC Hydro does not have a duty under s.35(1) of the *Constitution Act, 1982* to consult KLCN. The Commission Panel is satisfied that BC Hydro was responsive to concerns raised, because of KLCN's role as a stakeholder with an interest in the Project, and sought to consult; however, KLCN did not engage.

10.0 SUMMARY OF DETERMINATIONS, DIRECTIVES AND RECOMMENDATIONS

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page**
1.	The Panel determines that, with appropriate load shedding agreements, DCAT will provide the required reliability, regardless of whether the GDAT project is completed in a timely fashion.	39
2.	The Commission Panel finds that a project is required to resolve constraints in the existing 138kV Transmission System in the Dawson Creek area, to serve significant load growth, and to move toward reliable service. Accordingly, the need has been justified pending further findings in this Decision.	42
3.	The Commission Panel accepts BC Hydro's load forecast and notes it has been revised by BC Hydro using the best available known information.	42
4.	The Commission Panel is not persuaded that the DCAT Project, while needed, necessarily must be in service by April 30, 2014.	42
5.	The Commission Panel finds that Project Alternative 1, as proposed by BC Hydro, while not the least expensive option, is the most cost-effective transmission reinforcement alternative, as it provides significant flexibility to meet future anticipated growth, considering the available options.	81
6.	The Commission Panel finds that BC Hydro has adequately consulted the public.	99
7.	The Panel directs BC Hydro to specifically follow through on its plan to build a berm and/or a hedge to provide a visual and noise barrier between the BMT site plan and the Robinsons' property.	99
8.	The Commission Panel finds that the DCAT Project aligns with the *CEA* and Provincial Government policy.	106
9.	The Commission Panel accepts the routing and environmental treatments BC Hydro has applied to developing the DCAT Project.	108
10.	The Panel directs that as part of the GDAT Phase 2 application, BC Hydro provide more detailed information about the location of customer loads and the routing and ownership of all transmission and distribution lines that are expected to be built.	112

11.	The Panel finds that the System Extension Guidelines should not be applied as is, but when not inconsistent with TS 6, and in areas where TS 6 is silent, they can be considered.	119
12.	The Panel is not persuaded that the CPCN for the Project should be denied pending an amendment of TS 6 as suggested by AMPC.	127
13.	**Panel Recommendation:** If the review of transmission service rates is not concluded by mid 2014, or if it does not include a review of TS 6, this Panel recommends that the Commission should consider a review of TS 6 and invite all interested parties to participate in the review as this is a significant and urgent issue.	128
14.	The Panel finds that the TS 6 should be applied to individual customers, and not an aggregation of customers.	130
15.	The Panel also finds that it is appropriate to consider load added subsequent to the new customer taking service when applying TS 6.	130
16.	The Panel makes no specific directive with regard to the inclusion of generation reinforcement in the TS 6 calculation in the event that any of the five industrial customers increase the amount of load. However, the Panel recommends that this issue be examined in the forthcoming industrial tariff review.	131
17.	The Panel finds that the DCAT Project TS 6 calculation should not include the estimated costs of the Phase 2 GDAT project.	133
18.	The Panel determines that if the Phase 2 GDAT project is found to be needed in order to provide service to these five new industrial DCAT customers, the requirement for additional deposit or contribution should be assessed at that time.	134
19.	**Panel Recommendation:** The forthcoming industrial rate review should consider how deposits and contributions should be assessed when a project is phased.	134
20.	**Panel Recommendation:** The issue of additional deposits/contributions by DCAT customers should be examined by a future Panel when the Phase 2 GDAT CPCN application is heard.	134
21.	The Commission Panel is not approving the revision to section 8.3 of the Terms and Conditions of the Electric Tariff as proposed by BC Hydro at this time.	138
22.	The Commission Panel directs BC Hydro to recalculate the deposit/contribution requirement under TS 6, and, if applicable the Electric Tariff, for each DCAT customer and file the revised calculation with the Commission.	140
23.	The Commission Panel finds that the impacts of the Project on WMFN's treaty rights are medium.	155

24.	The Commission Panel has determined that the scope of the impact of the Project on WMFN is medium on the *Haida* spectrum and therefore the Panel finds that BC Hydro has a medium duty to consult.	157
25.	The Commission Panel finds consultation with WMFN on the DCAT Project is inadequate to the date of this Decision because BC Hydro has not yet obtained adequate knowledge of the potential impacts of the Project on WMFN's treaty rights nor consulted the WMFN on those impacts.	169
26.	The Commission Panel directs BC Hydro to provide the Commission with evidence of further consultation no later than 180 days from the issuance of this Order.	172
27.	The Commission Panel expects the further evidence will demonstrate consultation to a medium level on the *Haida* spectrum, addressing the deficiencies outlined in this Decision. The Commission also expects that this evidence will reveal any mitigation necessary respecting potential impacts.	172
28.	The Panel finds that BC Hydro's consultation with McLeod Lake, Saulteau, Blueberry River, Halfway River, Prophet River, Doig River, and Fort Nelson has been adequate.	179
29.	The Commission Panel finds that BC Hydro has met its duty to consult the Métis	180
30.	Given the evidence that KLCN is not recognized as a First Nation or under the *Indian Act*, and the lack of evidence to contradict this, the Commission Panel finds it likely that BC Hydro does not have a duty under s.35(1) of the *Constitution Act, 1982* to consult KLCN.	180

Dated at the City of Vancouver, in the Province of British Columbia, this 10th day of October 2012.

Original signed by:

Liisa A. O'Hara
Panel Chair/Commissioner

Original signed by:

Carol A. Brown
Commissioner

Original signed by:

David M. Morton
Commissioner

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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-144-12

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

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

BEFORE: L.A. O'Hara, Panel Chair/Commissioner
C.A. Brown, Commissioner
D.M. Morton, Commissioner

October 10, 2012

O R D E R

WHEREAS:

A. On July 11, 2011, British Columbia Hydro and Power Authority (BC Hydro) applied (the Application) pursuant to subsection 46(1) of the *Utilities Commission Act* (the Act) to the British Columbia Utilities Commission (Commission) for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Dawson Creek/Chetwynd Area Transmission Project (the Project) as described in the Application;

B. The Project is located in the Dawson Creek/Chetwynd area of north east British Columbia. Transmission capacity is needed in this area to enhance the quality of service to existing customers and to meet increasing customer load. The Project is BC Hydro's preferred alternative to meet the area's forecasted load growth;

C. The Project consists of three main components:

   i. The construction of the new Sundance Lake Substation (SLS) including the acquisition of 8.15 hectares to facilitate the space requirements of the new substation;

   ii. The construction of a double circuit 230 kV transmission line strung on steel monopoles from SLS to Bear Mountain Terminal (BMT) (60 km) and from BMT to Dawson Creek Substation (DAW) (12 km). A new 33 meter (m) right-of-way is required for the route; in portions where the route parallels existing transmission lines, the required additional width may be less.

   iii. The expansion of BMT including the acquisition of approximately 14 hectares of land to facilitate the additional equipment required for the Project.

D. The Project's expected cost is $222 million and the authorized budget is $257 million with a planned in-service date of April 30, 2014;

E. At the request of BC Hydro, the Commission Panel temporarily suspended the review process on November 30, 2011. The suspension was lifted on April 11, 2012;

F. The Commission held a Procedural Conference on May 2, 2012 in Vancouver, BC to discuss, inter alia, the Scope of the Review of the CPCN Application; Order G-184-11 sets out the Commission's Determinations in that regard;

G. The review of the Application was conducted primarily by way of a written hearing. The adequacy of First Nations' consultation was conducted in an Oral Hearing Phase held from July 9 to July 10, 2012;

H. The Commission has considered the evidence and arguments on whether the Crown's Duty to Consult and accommodate the First Nations up to the date of this Decision;

I. The Commission has considered the Application, the evidence and submissions presented.

NOW THEREFORE pursuant to sections 45, 46, 58 and 61 of the Act the Commission orders that:

1. The Crown's Duty to Consult with the West Moberly First Nation on the DCAT Project has not been adequately met, to the date of this Decision.

2. The Commission will grant a CPCN to BC Hydro for the DCAT Project, as set out in the Application as Alternative 1, subject to the following conditions:

   (a) Within 180 days of the date of this Order, BC Hydro shall file with the Commission evidence of further consultation, as directed in the accompanying Decision.

   (b) West Moberly First Nation will have 10 days from the date of the filing of the evidence to file a written response.

   (c) BC Hydro will then have 7 days from the date of the filing of West Moberly First Nation's response to file a written reply.

   The Commission will review the submissions and, if the further consultation is determined to be adequate to meet the Crown's duty to consult, as set out in this accompanying Decision, the CPCN will be granted.

3. If the CPCN is granted, BC Hydro is directed to file with the Commission semi-annual updates on the actual Project schedule and costs with a comparison to plan set out in the Application and any variances the Project may be encountering. The semi-annual progress reports will be filed within 45 days of the end of each reporting period.

…/3

4. If the CPCN is granted, BC Hydro is directed to file a final report within six months of the end or substantial completion of the Project. The final report is to include a reconciliation of actual and anticipated Project costs as set out in the Application and provide an explanation of any material costs in excess of $257.4 million.

5. The revision to section 8.3 of the Terms and Conditions of the Electric Tariff as proposed by BC Hydro is not approved at this time. The Panel may accept the proposed changes subject to receipt of the following clarifications:

   (a) BC Hydro is to specify how a new customer's load is to be allocated between Tariff Supplement 6 and the Electric Tariff for the purpose of the deposit/contribution calculation.

   (b) BC Hydro is to provide revised amended language for the Electric Tariff section 8.3 which specifically indentifies each section of Tariff Supplement 6 that is applicable to System Reinforcement.

6. Tariff Supplement 6 is to be applied to individual customers, and not an aggregation of customers. Accordingly, if the CPCN is granted, BC Hydro is directed to recalculate the deposit/contribution requirement under Tariff Supplement 6 and, if applicable, the Electric Tariff, for each DCAT customer and file the revised calculation with the Commission within 30 days of that Decision.

7. BC Hydro is directed to comply with all the directives of the Commission set out in the Decision issued concurrently with this Order.

DATED at the City Of Vancouver, in the Province Of British Columbia, this 10th day of October 2012.

BY ORDER

Original signed by:

L.A. O'Hara
Panel Chair/Commissioner

UTILITIES COMMISSION ACT

Commission may order improved service

25 If the commission, after a hearing held on its own motion or on complaint, finds that the service of a public utility is unreasonable, unsafe, inadequate or unreasonably discriminatory, the commission must

(a) determine what is reasonable, safe, adequate and fair service, and

(b) order the utility to provide it.

Commission may set standards

26 After a hearing held on the commission's own motion or on complaint, the commission may do one or more of the following:

(a) determine and set just and reasonable standards, classifications, rules, practices or service to be used by a public utility;

(b) determine and set adequate and reasonable standards for measuring quantity, quality, pressure, initial voltage or other conditions of supplying service;

(c) prescribe reasonable regulations for examining, testing or measuring a service;

(d) establish or approve reasonable standards for accuracy of meters and other measurement appliances;

(e) provide for the examination and testing of appliances used to measure a service of a utility.

Utility must provide service if supply line near

28 (1) On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.

(2) Before supplying the service under subsection (1) or making a connection for the purpose, or as a condition of continuing to supply the service, the public utility may require the owner or occupier to give reasonable security for repayment of the costs of making the connection as set out in the filed schedule of rates.

(2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).

(2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite

(a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or

(b) any previous decision of the commission.

(3) After a hearing and for proper cause, the commission may relieve a public utility from the obligation to supply service under this Act on terms the commission considers proper and in the public interest.

Public utility must provide service

38 A public utility must

(a) provide, and

(b) maintain its property and equipment in a condition to enable it to provide,

a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable

Certificate of public convenience and necessity

45 (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

(2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it

(a) to operate the plant or system, and

(b) subject to subsection (5), to construct and operate extensions to the plant or system.

(3) Nothing in subsection (2) authorizes the construction or operation of an extension that is a reviewable project under the *Environmental Assessment Act*.

(4) The commission may, by regulation, exclude utility plant or categories of utility plant from the operation of subsection (1).

(5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.

(6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

(6.1) and (6.2) [Repealed 2008-13-8.]

(7) Except as otherwise provided, a privilege, concession or franchise granted to a public utility by a municipality or other public authority after September 11, 1980 is not valid unless approved by

the commission.

(8) The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest.

(9) In giving its approval, the commission

(a) must grant a certificate of public convenience and necessity, and

(b) may impose conditions about

(i) the duration and termination of the privilege, concession or franchise, or

(ii) construction, equipment, maintenance, rates or service,

as the public convenience and interest reasonably require.

Procedure on application

46 (1) An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes.

(2) The commission has a discretion whether or not to hold any hearing on the application.

(3) Subject to subsections (3.1) to (3.3), the commission may, by order, issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.

(3.1) In deciding whether to issue a certificate under subsection (3) applied for by a public utility other than the authority, the commission must consider

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean*

Energy Act, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

(4) If a public utility desires to exercise a right or privilege under a consent, franchise, licence, permit, vote or other authority that it proposes to obtain but that has not, at the date of the application, been granted to it, the public utility may apply to the commission for an order preliminary to the issue of the certificate.

(5) On application under subsection (4), the commission may make an order declaring that it will, on application, under rules it specifies, issue the desired certificate, on the terms it designates in the order, after the public utility has obtained the proposed consent, franchise, licence, permit, vote or other authority.

(6) On evidence satisfactory to the commission that the consent, franchise, licence, permit, vote or other authority has been secured, the commission must issue a certificate under section 45.

(7) The commission may, by order, amend a certificate previously issued, or issue a new certificate, for the purpose of renewing, extending or consolidating a certificate previously issued.

(8) A public utility to which a certificate is, or has been, issued, or to which an exemption is, or has been, granted under section 45 (4), is authorized, subject to this Act, to construct, maintain and operate the plant, system or extension authorized in the certificate or exemption.

REGULATORY PROCESS

British Columbia Hydro and Power Authority (BC Hydro) filed the application for the Dawson Creek/Chetwynd Area Transmission (DCAT) Project on July 11, 2011. By Order G-132-11 the Commission established an initial Regulatory Timetable, including two rounds of Information Requests (IR) and a Procedural Conference planned for September 22, 2011. As requested by BC Hydro, the Procedural Conference was subsequently rescheduled to November 4, 2011.

Following the Procedural Conference, the Commission issued Order G-184-11 and a Revised Regulatory Timetable which provided for a third round of IRs.

On November 9, 2011, West Moberly First Nations (WMFN) requested that the Commission "exercise its power and discretion, pursuant to section 74(e) of the *Utilities Commission Act,* to adjourn these proceedings until such time as a study outlining the impacts of BC Hydro's proposed DCAT Project on WMFN is completed." WMFN submitted that the study must be completed to allow the requisite consultation and accommodation between the Nation and BC Hydro, and that the study must be completed prior to WMFN filing evidence. (Exhibit C5-13)

By letter dated November 23, 2011, BC Hydro requested that the DCAT Project hearing process be temporarily suspended and no further steps be taken until so requested by BC Hydro. BC Hydro stated that questions raised by Parties in their IR #3 and by the Panel in IR #1 addressed policy and factual areas that were not anticipated by BC Hydro for a Certificate of Public Convenience and Necessity filing. BC Hydro further stated it required time to collaborate with Government and potentially stakeholders before setting our policy positions on some fundamental issues. (Exhibit B-19) By letter dated November 30, 2011, the Commission Panel granted BC Hydro's request and temporarily suspended the DCAT review process. (Exhibit A-23) This meant that all questions included in the IR Round No. 3 and the Panel IRs remained unanswered and outstanding.

On November 28, 2011, WMFN advised it had reached an agreement in principle with BC Hydro to conduct an impact assessment study. WMFN further requested that the Commission delay consideration of its adjournment application until such time as BC Hydro requests to re-start the regulatory process. (Exhibit C5-15)

By letter dated March 23, 2012, BC Hydro requested that the DCAT Project review be reactivated and made submissions with respect to the manner in which that reactivation would be structured. Because those submissions were based in part on evidentiary material not currently on the record of the DCAT proceeding, BC Hydro also filed Supplemental Evidence. (Exhibit B-22)

On April 3, 2012, WMFN confirmed that the Nation and BC Hydro have come to an agreement on the outstanding Capacity Funding Agreement and for the terms of reference to conduct of the Impact Assessment Study. (Exhibit C5-18)

On April 11, 2012, the Commission Panel lifted the temporary suspension, directed BC Hydro to identify which outstanding IRs were out of scope and which IRs had been answered in Exhibit B-22 and sought Intervener comments. The Panel also established the second Procedural Conference for May 2, 2012. (Exhibit A-26)

By Order G-56-12 the Commission Panel established the scope of the Application review, directed BC Hydro to respond to the identified outstanding IR's and further amended the Regulatory Timetable. The Panel also ruled that the review will proceed by way of a written hearing with IR No. 4, followed by an oral hearing limited to the adequacy of First Nations' consultation. (Exhibit A-28)

On June 15, 2012 the Commission Panel requested that specific matters related to Electric Tariff No. 6 be addressed in Final Submission by parties. (Exhibit A-31)

On June 29, 2012, the Commission confirmed that the Oral Public hearing will commence on July 9, 2012 as no parties have advised that it is not necessary to proceed with an oral phase on First Nations' consultation. (Exhibit A-32)

On July 5, 2012, WMFN submitted its community-based environmental assessment report (CBEA Report). (Exhibit C5-20) On July 6, 2012, BC Hydro filed its Evidentiary Update concerning BC Hydro's consultations with WMFN in respect of the DCAT Project. (Exhibit B-34) During the Oral Phase both WMFN and BC Hydro introduced witness panels.

During the Oral Phase the Commission Panel indicated it plans to view the DCAT Project route, including potential substation locations as well as the confluence of the Pine and Murray Rivers to obtain further context. By letter dated July 13, 2012, the Panel confirmed it will proceed with the flyover on July 23, 2012 as no party had objected. (Exhibit A-33)

BC Hydro's Final Submission was due on July 24, 2012, Intervener Final Submissions on August 2, 2012 and BC Hydro's Reply Submission on August 8, 2012.

Total Forecast and Percentage Shares (2011)
Of Gas Producer and Other Load

	UPDATE	APPLICATION	DIFFERENCE	Gas Producer	Other
Fiscal	2011	2010	(MW)	% Share	% Share
2011		101			
2012	114	135	-21	29.8%	70.2%
2013	150	153	-3	36.0%	64.0%
2014	260	224	36	63`.1%	36.9%
2015	329	268	61	70.5%	29.5%
2016	377	306	71	74.0%	26.0%
2017	385	320	65	74.5%	25.5%
2018	388	324	64	74.5%	25.5%
2019	395	328	67	74.9%	25.1%
2020	401	331	70	74.6%	25.4%
2021	418	343	75	75.6%	24.4%
2022	422	346	76	75.6%	24.4%
2023	422	350	72	75.6%	24.4%
2024	422	352	70	75.6%	24.4%
2025	423	355	68	75.4%	24.6%
2026	423	357	66	75.4%	24.6%
2027	424	359	65	75.2%	24.8%
2028	424	345	79	75.2%	24.8%
2029	425	330	95	75.1%	24.9%
2030	425	319	106	75.1%	24.9%
2031	425	308	117	75.1%	24.9%
2032	423	290	133	74.9%	25.1%
2033	420	273	147	74.8%	25.2%
2034	415	259	156	74.2%	25.8%
2035	406	245	161	73.6%	26.4%
2036	397	233	164	73.0%	27.0%
2037	388	223	165	72.4%	27.6%
2038	375	213	162	71.5%	28.5%
2039	360	204	156	70.3%	29.7%
2040	347	197	150	69.2%	30.8%
2041	334	190	144	68.0%	32.0%

Source: Created from Exhibit B-1, Appendix B, Table 1 and Exhibit B-5, BCUC 1.28.1; Exhibit B-22

List of Acronyms

AIA	Archeological Impact Assessment
AMEC	AMEC Americas Limited
AMPC	Association of Major Power Customers
ARC	ARC Resources Ltd.
BC Hydro, the Applicant	British Columbia Hydro and Power Authority
BCOAPO	B.C. Old Age Pensioners' Organization *et al.*
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCSEA	BC Sustainable Energy Association and the Sierra Club of British Columbia
BCTC	BC Transmission Corporation
BCUC, the Commission	British Columbia Utilities Commission
Blueberry River	Blueberry River First Nation
BMT	Bear Mountain Terminal Substation
BMW	Bear Mountain Wind Power IPP
CAPP	Canadian Association of Petroleum Producers
CBL	customer baseline load
CCGT	Combined cycle gas turbines
CEA	*Clean Energy Act*
CEA	Clean Energy Association of B.C.
CEC	Commercial Energy Consumers Association of British Columbia
CFA	Capacity Funding Agreement
CIAC	contribution in aid of construction
COPE	Canadian Office and Professional Employees Union Local 378
CPCN	Certificate of Public Convenience and Necessity
CSI	Current Solutions Incorporated
CWD	Chetwynd Substation
DAW	Dawson Creek Substation

DBB	design-bid-build
DCAT, Application	Dawson Creek/Chetwynd Area Transmission Project
DC Area Load Forecast	load forecast in the Dawson Creek and Groundbirch areas (Sec 3.2.1
Doig River	Doig River First Nation
DSM	demand side management
DWG	Dawson Creek Generating Station/230kV/138kV substation
EENS	Expected Energy Not Served
EMF	Electric and Magnetic Fields
EMP	Environmental Management Plan
Encana	Encana Corporation
EnCana	EnCana Power and Processing ULC
EOA	Environmental Overview Assessment
Extension Guidelines	Utility System Extension Test Guidelines
FJN	Fort St. John Substation
Fort Nelson	Fort Nelson First Nations
GDAT	Greater Dawson Creek Area Transmission/Phase 2/GMS to Dawson Creek Area Transmission
GDP	Gross Domestic Product
GHG	Greenhouse gas
GMS	Gordon M. Shrum generating station
ha	hectares
Halfway River	Halfway River
IAS	Impact Assessment Study
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IDC	interest during construction
IRs	Information Requests
IRP	Integrated Resource Plan
KIS	Kiskatinaw Substation
KLCN	Kelly Lake Cree Nation

km	kilometers
kV	kilovolt
kVA/kV.A	kilovolt amps
LAP	Tembec Substation
LGS	Large General Service
LNG	Liquefied Natural Gas
McLeod Lake	McLeod Lake Indian Band
MEM	Ministry of Energy and Mines
mG	milliGauss
MoT	Ministry of Transportation
MRS	Mandatory Reliability Standards
Murphy	Murphy Oil Company Ltd.
MVA/MV.A	megavolt ampers
MVAR	megavolt ampers reactive
MW	Megawatt
MWh	Megawatt hour
NGO's	non-governmental organizations
NPV	Net Present Value
O&M	Operating and maintenance costs
Prophet River	Prophet River First Nation
PRRD	Peace River Regional District
PV	Present Value
RAS	Remedial Action Scheme
ROW	right-of-way
Saulteau	Saulteau First Nation
SCC	Supreme Court of Canada
SCGT	Single cycle gas turbines
SD	Special Direction

shale gas	unconventional gas reserves
Shell	Shell Canada Ltd.
SLS	Sundance Lakes Substation
SNK	Sukunka Substation
SVC	static VAR compensator
TAY	Taylor
T&C	Electric Tariff Terms and Conditions
the Industrials	Methanex Corporation, Council of Forest Industries and the Mining Association of British Columbia
the Robinsons	Marilyn and Gary Robinson
TLE	Treaty Land Entitlement
TOR	Terms of Reference
TS 6	Tariff Supplement 6
TUS	Traditional Use Study
UCA	*Utilities Commission Act*
UCC	unit capacity cost
VECs	Valued Ecosystem Components
VSCs	Valued Social Components
WECC	Western Electric Coordinating Council
WDM	Wildmare Substation
WMFN	West Moberly First Nations

APPEARANCES

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L. WORTH T. BRAITHEWAITE A. WAUGH	Consumers' Association B.C. Branch, B.C. Old Age Pensioners' Organization, Counsel of Senior Citizens' Organizations, Federated Anti-Poverty Groups Of B.C., West End Seniors' Network
P. HILDEBRAND M. CRUICKSHANK	City of Dawson Creek
A. RANA R. WILLSON B. MUIR	West Moberly First Nations
J. LANDRY	Shell Canada

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Application for a Certificate of Public Convenience and Necessity
for the Dawson Creek/Chetwynd Area Transmission Project

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated July 26, 2011 – Order G-132-11 establishing Initial Regulatory Timetable and Procedural Conference
A-2	Letter dated July 27, 2011 – Appointment of Commission Panel
A-3	Letter dated August 17, 2011 – Issuing Commission Information Request No. 1 to BC Hydro
A-4	Letter dated September 15, 2011 – Order G-160-11 issuing Amended Regulatory Timetable – Rescheduling of Procedural Conference
A-5	Letter dated September 22, 2011 – Interim Participant Assistance/Cost Award (PACA)
A-6	Letter dated September 29, 2011 – Response to BC Hydro request to Comment
A-7	Letter dated October 4, 2011 – West Moberly First Nation Extension to file Information Request No. 2
A-8	Letter dated October 6, 2011 – Issuing Commission Information Request No. 2 to BC Hydro
A-9	**CONFIDENTIAL** Letter dated October 6, 2011 – Issuing CONFIDENTIAL Commission Information Request No. 2 to BC Hydro
A-10	Letter dated October 7, 2011 –Comments regarding the submission of CEC IR-2
A-11	Letter dated October 13, 2011 – Request BC Hydro response regarding Confidential Information Request No. 2

Exhibit No.	Description
A-12	Letter dated October 13, 2011 – Response to West Moberly First Nation additional filing extension for Information Request No. 2
A-13	Letter dated October 14, 2011 – Panel Determination on the CEC request for interim PACA Funding
A-14	Letter dated October 17, 2011 – Request BC Hydro response regarding West Moberly First Nation access to Confidential Information Request No. 2
A-15	Letter dated October 18, 2011 –Determination regarding confidential IR No. 2 questions
A-16	Letter dated October 26, 2011 – Procedural Conference Items
A-17	Letter dated October 27, 2011 – Response to BC Hydro
A-18	Letter dated November 8, 2011 – Order G-184-11 issuing Revised Regulatory Timetable
A-19	Letter dated November 14, 2011 – Request comments regarding WMFN request for stay of Application
A-20	Letter dated November 15, 2011 – Commission Panel Information Request No. 1 to BC Hydro
A-21	Letter dated November 18, 2011 – Commission Information Request No. 3 to BC Hydro
A-22	Letter dated November 24, 2011 – Commission Response to Request for Suspension of Hearing
A-23	Letter dated November 30, 2011 – Suspension of Hearing until Further Notice
A-24	Letter dated December 13, 2011 – Commission Response to Request for Late Intervener Status
A-25	Letter dated March 27, 2012 - Request to Interveners to Provide Comments Regarding Reactivation of Hearing Process
A-26	Letter dated April 11, 2012 – Letter L-23-12 Hearing Reactivation
A-27	Letter dated April 24, 2012 – Letter L-26-12 Request Comments on Draft Revised Regulatory Timetable

Exhibit No.	Description
A-28	Letter dated May 7, 2012 – Commission Order G-56-12 issuing Revised Regulatory Timetable
A-29	Letter dated May 11, 2012 – Commission Information Request No. 4 to BC Hydro
A-30	Letter dated June 14, 2012 - Commission Information Request No. 1 to CSI
A-31	Letter dated June 15, 2012 - Letter L-36-12 Specific Matters Relating to Electric Tariff No. 6 to be Addressed in Final Submissions
A-32	Letter dated June 29, 2012 – Confirmation of Oral Hearing on First Nations' Consultation
A-33	Letter dated July 13, 2012 – Letter L-41-12 issuing Revised Regulatory Timetable
A-34	Letter dated August 8, 2012 – Commission Response regarding WMFN Confidential Final Submission
A2-1	Letter dated November 3, 2011 – Commission staff submission British Columbia Hydro and Power Authority 2010 Electrical Load Forecast for 2010/11 to 2030/31
A2-2	Letter dated June 13, 2012 - Commission staff submission Utility System Extension Test Guidelines dated September 5, 1996
A2-3	Letter dated June 29, 2012 - Commission staff submission British Columbia Transmission Corporation – Peace Region Load Serving Capability June 24, 2009 Information Release – Load Serving Capability for New Load Interconnections in the Dawson Creek and Chetwynd Area

APPLICANT DOCUMENTS

B-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)** Letter dated July 11, 2011 – Application for Certificate of Public Convenience and Necessity for the Dawson Creek-Chetwynd Area Transmission Project
B-1-1	Letter dated July 11, 2011 – BCH Submitting Errata revised Appendix E
B-1-2	Letter dated September 15, 2011 – BCH Submitting Errata to the Application
B-1-3	Letter dated March 23, 2012 – BCH Submitting Updates to the Application
B-2	Letter dated July 22, 2011 – BCH Submitting Workshop Presentation

Exhibit No.	Description
B-3	Letter dated August 16, 2011 – BCH Submitting Compliance with BCUC Order G-132-11 Directive 3
B-4	Letter dated September 13, 2011 – BCH Request for Amendments to the Regulatory Timetable
B-5	Letter dated September 15, 2011 – BCH Responses to BCUC Information Request No. 1
B-5-1	**CONFIDENTIAL** Letter dated September 15, 2011 – BCH CONFIDENTIAL Responses to BCUC Information Request No. 1
B-5-2	Letter dated September 22, 2011 – BCH Submitting Amended Response to BCUC IR 1.38.2.1
B-5-3	Letter dated September 29, 2011 – BCH Response to BCUC IR 1.38.2.2
B-5-4	**CONFIDENTIAL** Letter dated September 29, 2011 – BCH CONFIDENTIAL Response to BCUC IR 1.38.2.3
B-6	Letter dated September 22, 2011 – BCH Submitting Responses to Intervener Information Requests No. 1
B-6-1	**CONFIDENTIAL** Letter dated September 22, 2011 – BCH Submitting CONFIDENTIAL Responses to Intervener Information Requests No. 1
B-6-2	Letter dated September 29, 2011 – Revised Responses to CEC IR 1.1.10, COPE IR 1.1.1
B-7	Letter dated September 28, 2011 – BCH Submitting request to comment on CEC interim PACA funding application
B-8	Letter dated September 29, 2011 – BCH Submission regarding WMFN requesting access to Confidential Responses to BCUC Information Request No. 1 (Exhibit C5-3)
B-9	Letter Dated October 3, 2011– BCH Submission regarding WMFN request for an extension (Exhibit C5-5)
B-10	Letter Dated October 7, 2011– BCH Submitting comments on Interim PACA Funding Application of CECBC

Exhibit No.	Description
B-11	Letter Dated October 14, 2011– BCH Submitting Response to Exhibit A-11
B-12	Letter Dated October 18, 2011– BCH Submitting Response to Exhibit A-14
B-13	Letter Dated October 24, 2011– BCH Reply Submission in Compliance with Exhibit A-14
B-14	Letter Dated October 27, 2011– BCH Response to BCUC Information Request No. 2
B-14-1	**CONFIDENTIAL** Letter Dated October 27, 2011– BCH CONFIDENTIAL Response to BCUC Information Request No. 2
B-14-2	Letter Dated November 1, 2011– BCH Response to BCUC Information Request No. 2.29.2
B-14-3	**CONFIDENTIAL** Letter Dated November 1, 2011– BCH CONFIDENTIAL Response to BCUC Information Request No. 2.29.2
B-15	Letter Dated October 27, 2011– BCH Response to Interveners Information Request No. 2
B-15-1	Letter Dated November 1, 2011– BCH Response to WMFN
B-16	**CONFIDENTIAL** Letter Dated November 1, 2011– BCH CONFIDENTIAL Response to WMFN Confidential Request
B-17	Letter dated November 3, 2011 – BCH Submitting Public Response to BCUC Confidential Information Request No. 2
B-17-1	**CONFIDENTIAL** Letter dated November 3, 2011 – BCH Submitting CONFIDENTIAL Response to BCUC Confidential Information Request No. 2
B-18	Letter dated November 21, 2011 – BCH Submitting comments regarding WMFN Application for Adjournment
B-19	Letter dated November 23, 2011 – BCH Submitting Request for Suspension of Proceeding and Comments on Information Requests
B-20	Letter dated November 29, 2011 – BCH Submitting reply to Interveners comments
B-21	Letter dated March 7, 2012 - BCH Submitting Notice of Reactivation Application
B-22	Letter dated March 23, 2012 – BCH Submitting Application Reactivation Request

Exhibit No.	Description
B-23	**CONFIDENTIAL** Letter dated March 23, 2012 – BCH Submitting CONFIDENTIAL Evidence
B-24	Letter dated April 5, 2012 – BCH Reply to Intervener Procedural Comments
B-25	Letter dated April 17, 2012 – BCH Submitting Response to Exhibit A-26
B-26	Letter dated April 12, 2012 – BC Hydro Response to Lance Mulvahill Exhibit E-1
B-27	Submitted at Procedural Conference May 2, 2012 - DCAT Round 3 IRS Which BC Hydro Commits to Answering
B-28	Submitted at Procedural Conference May 2, 2012 - BC Hydro Proposed Regulatory Timetable
B-29	Letter dated May 24, 2012 - BCH Submitting Responses to BCUC and Interveners Information Request No. 3 and BCUC Panel Information Request No. 1
B-29-1	**CONFIDENTIAL** Letter dated May 24, 2012 - BCH Submitting CONFIDENTIAL Responses to BCUC and Interveners Information Request No. 3 and BCUC Panel Information Request No. 1
B-30	Letter dated May 24, 2012 - BCH Submitting Responses to BCUC and Interveners Information Request No. 4
B-30-1	Letter dated May 25, 2012 - BCH Submitting Responses to CEC Information Request No. 4
B-31	Letter dated July 4, 2012 - BCH Submitting Security Arrangements Update
B-32	Letter dated July 5, 2012 - BCH Submitting First Nations Consultation Summary
B-33	**CONFIDENTIAL** Letter dated July 5, 2012 - BCH Submitting CONFIDENTIAL BC Hydro and West Moberly First Nations Log
B-34	Letter dated July 6, 2012 - BCH Submitting Evidentiary Update
B-35	Submitted at Oral Hearing July 9, 2012 - OUTLINE (TABLE OF CONTENTS) OF DRAFT EXHIBIT C5-20 PROVIDED BY MR. SANDERSON
B-36	Submitted at Oral Hearing July 10, 2012 - POWERPOINT PRESENTATION DATED JUNE 2010

Exhibit No.	Description
B-37	Submitted at Oral Hearing July 10, 2012 - CURRICULUM VITAE OF TIM SLANEY
B-38	Submitted at Oral Hearing July 10, 2012 - LIST OF DISCIPLINE LEADS AND SENIOR PERSONNEL
B-39	Submitted at Oral Hearing July 10, 2012 - REPLACEMENT TABLE FOR PAGE 111 OF 207 EXHIBIT B-1, APPENDIX F
B-40	Submitted at Oral Hearing July 10, 2012 - FULL SET OF MAPS WHICH HAD BEEN OMITTED FROM EXHIBIT B-34
B-41	Submitted at Oral Hearing July 10, 2012 - REPORT ENTITLED "POPULATION STATUS OF THREATENED CARIBOU HERDS IN THE CENTRAL ROCKIES ECO-REGION OF BRITISH COLUMBIA, 2011" BY DALE SEIP AND ELENA JONES, MAY 2011
B-42	**CONFIDENTIAL** Letter dated July 10, 2012 – BCH Submitting CONFIDENTIAL West Moberly First Nations Log and Relevant Material
B-43	Letter dated July 11, 2012 – BCH Submitting confirmation of DCAT tour
B-44	Letter dated July 12, 2012 – BCH Submitting response to WMFN response regarding DCAT tour
B-45	Letter dated July 20, 2012 – BCH Submitting Security Arrangements Update
B-46	Letter dated July 25, 2012 – BCH Submitting Tour Materials

INTERVENER DOCUMENTS

C1-1	**V.W.RUSKIN & ASSOCIATES (VR)** Letter dated July 16, 2011 **VIA EMAIL** – Request for Intervener Status by Vernon Ruskin
C1-2	Letter Dated September 27, 2011 Via Email –VW Submitting comments
C1-3	Letter Dated October 11, 2011 Via Email – VR Submitting comments regarding the CEC PACA Application
C1-4	Letter Dated November 2, 2011 Via Email – VR Submitting Comment on Procedural Conference
C2-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CEC) VIA EMAIL -** Letter Dated July 21, 2011- Request for Intervener Status by Christopher Weafer

Exhibit No.	Description
C2-2	Letter Dated August 24, 2011 – CEC Submitting Information Request No. 1
C2-3	Letter Dated October 6, 2011 – CEC Submitting extension request for Information Request No. 2
C2-4	Letter Dated October 11, 2011 – CEC Information Request No. 2
C2-5	Letter Dated October 12, 2011 – CEC Submitting Reply Comments on Interim PACA
C2-6	Letter Dated October 28, 2011 – CEC Submitting Response to Exhibit A-13
C2-7	Letter Dated November 2, 2011– CEC Submitting Comment on Procedural Conference
C2-8	Letter Dated November 2, 2011– CEC Submitting notice of intent to provide evidence
C2-9	Letter dated November 18, 2011 – CEC Submitting Information Request No. 3 to BC Hydro
C2-10	Letter dated November 28, 2011 – CEC Submitting Comment on BC Hydro request for adjournment
C2-11	Letter dated April 3, 2012 – CEC Submitting Comments Regarding the Proposed Reactivation of Hearing
C2-12	Letter dated April 24, 2012 – CEC Submitting Comments Regarding BC Hydro's response to Exhibit A-26
C2-13	Letter dated May 14, 2012 – CEC Submitting Information Request No. 4
C3-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated July 28, 2011- Request for Intervener Status by Matthew Keen, Richard Stout, Lloyd Guenther and Brian Wallace
C3-2	Letter Dated November 2, 2011– AMPC Submitting Comment on Procedural Conference
C3-3	Letter dated November 18, 2011 – AMPC Submitting Information Request No. 3 to BC Hydro
C3-4	Letter dated November 21, 2011 – AMPC Submitting comments regarding WMFN Application for Adjournment

Exhibit No.	Description
C3-5	Letter dated November 24, 2011 – AMPC Submitting comments regarding Suspension of Hearing
C3-6	Letter dated April 3, 2012 – AMPC Submitting Comments Regarding the Proposed Reactivation of Hearing
C3-7	Letter dated April 10, 2012 – AMPC Submitting Comments Regarding BC Hydro's supplemental letter commenting on intervener responses
C3-8	Letter dated April 24, 2012 – AMPC Submitting Response to BC Hydro April 17, 2012 letter
C3-9	Letter dated May 14, 2012 – AMPC Submitting Information Request No. 4 to BC Hydro
C3-10	Letter dated June 7, 2012 – AMPC Submitting Evidence
C3-11	Letter dated June 14, 2012 – AMPC Submitting Response to BCOAPO Information Request No.1
C3-12	Letter dated June 28, 2012 – AMPC Submitting Response to BCSEA Information Request No.1
C3-13	Letter dated July 6, 2012 – AMPC Will Not Participate in Oral Hearing
C4-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION LOCAL 378 (COPE 378) VIA EMAIL** Letter Dated July 28, 2011- Request for Intervener Status by Mark Oulton
C4-2	Letter Dated August 24, 2011 – Cope378 Submitting Information Request No. 1
C4-3	Letter Dated September 14, 2011 - Cope378 Submitting Comments regarding Exhibit B-4
C4-4	Letter Dated September 13, 2011 - Cope378 Updating Contact Information
C4-5	Letter Dated September 26, 2011 – Cope 378 Comment regarding Exhibit A-5
C4-6	Letter Dated October 6, 2011 – Cope378 Submitting Information Request No. 2
C4-7	Letter Dated November 2, 2011– Cope378 Submitting Comment on Procedural Conference

Exhibit No.	Description
C4-8	Letter dated November 17, 2011 – Cope378 Submitting Information Request No. 3
C4-9	Letter dated November 17, 2011 – Cope378 Submitting response to Exhibit A-19
C4-10	Letter dated November 28, 2011 – COPE378 Submitting Comment on BC Hydro request for adjournment
C5-1	**WEST MOBERLY FIRST NATIONS (WMFN)** Online registration dated August 3, 2011 - Request for Intervener Status by Allisun Rana
C5-2	Letter Dated August 24, 2011 – WMFN Submitting Information Request No. 1
C5-3	Letter Dated September 22, 2011 - WMFN Submitting Response to BC Hydro Confidential Filings
C5-4	Letter Dated September 30, 2011 - WMFN Submitting comments regarding BC Hydro Confidential Filings
C5-5	Letter Dated October 3, 2011- WMFN Request for submission or Information Request No. 2
C5-6	Letter Dated October 4, 2011- WMFN Submitting comments regarding Exhibit B-9
C5-7	Letter Dated October 6, 2011- WMFN Submitting comments regarding confidential Information Requests
C5-8	Letter Dated October 13, 2011 - WMFN Submitting Information Request No. 2
C5-8-1	**CONFIDENTIAL** Letter Dated October 13, 2011 - WMFN Submitting Confidential Information Request No. 2
C5-9	Letter Dated October 17, 2011 – WMFN Submitting comments regarding Exhibit B-11
C5-10	Letter Dated October 21, 2011 – WMFN Responses to Exhibits_A-9-and-B-12
C5-11	Letter Dated November 2, 2011– WMFN Submitting Comment on Procedural Conference
C5-12	Letter Dated November 2, 2011– WMFN Submitting notice of intent to provide evidence

Exhibit No.	Description
C5-13	Letter dated November 9, 2011 – WMFN Submitting Adjournment Request
C5-14	Letter dated November 23, 2011 – WMFN Reply Submission on adjournment application
C5-15	Letter dated November 28, 2011 – WMFN Reply Submission on BC Hydro request for adjournment
C5-16	Letter dated April 4, 2012 – WMFN Submitting Comment on MEM Submission
C5-17	Letter dated April 4, 2012 – WMFN Submitting Comment on SC Submission
C5-18	Letter dated April 3, 2012 – WMFN Submitting Comments Regarding the Proposed Reactivation of Hearing
C5-19	Letter dated June 6, 2012 - WMFN Submitting Draft Summary of the Evidence of WMFN Chief Roland Willson
C5-20	Letter dated July 5, 2012 - WMFN Submitting Report
C5-21	Letter dated July 5, 2012 - WMFN Submitting Oral Hearing Materials and Evidence
C5-22	Submitted at Oral Hearing July 10, 2012 - COPY OF WEST MOBERLY POWERPOINT PRESENTATION
C5-23	Letter dated July 12, 2012 – WMFN Submitting Response to BCH proposed tour
C6-1	**MILL VALLEY AND INDIAN CREEK LAND OWNERS GROUP (MVICLOG)** Letter Dated August 12, 2011- Request for Intervener Status by Gordon Reid
C7-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** (previously BC Old Age Pensioner Organization et al) Via **EMAIL** Letter Dated August 15, 2011 – Request for Intervener Status by Leigha Worth
C7-2	Letter Dated August 24, 2011 – BCOAPO et al Submitting Information Request No. 1
C7-3	Letter Dated October 6, 2011 – BCOAPO et al Submitting Information Request No. 2
C7-4	Letter Dated October 12, 2011 – BCOAPO et al Submitting Comments regarding Interim PACA
C7-5	Letter Dated November 2, 2011– BCOAPO et al Submitting Comment on Procedural Conference

Exhibit No.	Description
C7-6	Letter dated November 18, 2011 – BCOAPO Submitting Information Request No. 3 to BC Hydro
C7-7	Letter dated November 21, 2011 – BCOAPO Submitting comments regarding WMFN Application for Adjournment
C7-8	Letter dated November 28, 2011 – BCOAPO Submitting Comment on BC Hydro request for adjournment
C7-9	Letter dated April 3, 2012 – BCOAPO et al Submitting Comments Regarding the Proposed Reactivation of Hearing
C7-10	Letter dated April 5, 2012 – BCOAPO Submitting Undertaking of Confidentiality for Eugene Kung
C7-11	Letter dated April 5, 2012 – BCOAPO Submitting Undertaking of Confidentiality for Leigha Worth
C7-12	Letter dated April 11, 2012 – BCOAPO Submitting Undertaking of Confidentiality for William Harper
C7-13	Letter dated April 24, 2012 – BCOAPO Submitting Comments Regarding BC Hydro's response to Exhibit A-26
C7-14	Letter dated May 14, 2012 – BCOAPO Submitting Information Request No. 4
C7-15	Letter dated June 14, 2012 - BCOAPO Information Request No. 1 to CSI
C7-16	Letter dated June 14, 2012 - BCOAPO Information Request No. 1 to AMPC
C7-17	Letter dated July 13, 2012 – BCOAPO comment regarding Revised Regulatory Timetable
C7-18	Letter dated July 23, 2012 – BCOAPO Submitting notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C7-19	Letter dated July 25, 2012 – BCPSO Submitting Confidential Undertaking
C8-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) VIA WEB** Letter Dated August 15, 2011 – Request for Intervener Status by William J. Andrews
C8-2	Letter Dated August 24, 2011 – BCSEA Submitting Information Request No. 1

Exhibit No.	Description
C8-3	Letter Dated September 27, 2011 Via Email – BCSEA Submitting comments on CEC proposal
C8-4	Letter Dated October 6, 2011 – BCSEA Submitting Information Request No. 2
C8-5	Letter Dated November 2, 2011– BCSEA Submitting Comment on Procedural Conference
C8-6	Letter dated November 18, 2011 – BCSEA Submitting Information Request No. 3 to BC Hydro
C8-7	Letter dated November 25, 2011 – BCSEA Submitting Comments Regarding the Proposed Suspension of Hearing
C8-8	Letter dated April 3, 2012 – BCSEA Submitting Comments Regarding the Proposed Reactivation of Hearing
C8-9	Letter dated May 14, 2012 – BCSEA Submitting Information Request No. 4 to BC Hydro
C8-10	Letter dated June 14, 2012 - BCSEA Information Request No. 1 to CSI
C8-11	Letter dated June 14, 2012 - BCSEA Information Request No. 1 to AMPC
C9-1	**SIERRA CLUB OF BRITISH COLUMBIA (SCBC) VIA WEB** Letter Dated August 15, 2011 – Request for Intervener Status by William J. Andrews
C10-1	**CLEAN ENERGY ASSOCIATION OF B.C. (CEA) VIA EMAIL –** Letter Dated August 15,2011 – Request for Intervener Status by David Austin
C10-2	Letter Dated October 4, 2011 – CEA Submission regarding PACA
C10-3	Letter Dated October 6, 2011 – CEA Submitting Information Request No. 2
C10-4	Letter Dated November 2, 2011– CEA Submitting Comment on Procedural Conference
C10-5	Letter dated November 18, 2011 – CEA Submitting Information Request No. 3 to BC Hydro
C10-6	Letter dated November 28, 2011 – CEA Submitting Comment on BC Hydro request for adjournment

Exhibit No.	Description
C10-7	Letter dated April 3, 2012 – CEA Submitting Comments Regarding the Proposed Reactivation of Hearing
C11-1	**GARY AND MARILYN ROBINSON (GMR)** Letter Dated December 12, 2011 - Request for Late Intervener Status by Darryl Carter
C11-2	Letter Dated March 19, 2012 – GMR Submitting comments regarding Exhibit B-22
C11-3	Letter Dated December 16, 2011 – GMR Submitting Information Request
C11-4	Letter Dated May 8, 2012 – GMR Submitting comments regarding Exhibit A-28
C11-5	Letter Dated May 14, 2012 – GMR Submitting Counsel Information
C11-6	Letter Dated May 14, 2012 – GMR Submitting Evidence
C12-1	**CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS (CAPP)** Letter Dated March 8, 2012 - Request for Late Intervener Status by James Smellie
C12-2	Letter dated April 3, 2012 – CAPP Submitting Comments Regarding the Proposed Reactivation of Hearing
C13-1	**AIR LIQUIDE CANADA (ALC)** Letter Dated March 9, 2012 - Request for Late Intervener Status by Mark Underhill
C13-2	Letter dated April 3, 2012 – ALC Submitting Comments Regarding the Proposed Reactivation of Hearing
C14-1	**SHELL CANADA LIMITED (SC)** Letter Dated March 14, 2012 - Request for Late Intervener Status by Naomi Sanderson and John Landry
C14-2	Letter dated April 3, 2012 – SC Submitting Comments Regarding the Proposed Reactivation of Hearing
C14-3	Letter dated July 13, 2012 – SC Submitting Comment regarding site visit
C15-1	**CURRENT SOLUTIONS INCORPORATED (CSI)** Letter Dated March 19, 2012 - Request for Late Intervener Status by Jamie Shand
C15-2	Letter dated April 3, 2012 – CSI Submitting Comments Regarding the Proposed Reactivation of Hearing
C15-3	Letter dated April 24, 2012 – CSI Submitting Comments Regarding BC Hydro's response to Exhibit A-26

Exhibit No.	Description
C15-4	Letter dated May 14, 2012 – CSI Submitting Information Request No. 4
C15-5	Letter dated June 7, 2012 - CSI Submitting Evidence
C15-6	Letter dated June 28, 2012 – CSI Submitting Response to BCUC Information Request No.1
C15-7	Letter dated June 28, 2012 – CSI Submitting Response to BCSEA and BCOAPO Information Request No.1
C15-8	Letter dated July 9, 2012 – CSI Will Not Participate in Oral Hearing
C16-1	**MINISTRY OF ENERGY AND MINES (MEM)** Letter Dated March 19, 2012 - Request for Late Intervener Status by Jennifer Champion and Les MacLaren
C16-2	Letter dated April 3, 2012 – MEM Submitting Comments Regarding the Proposed Reactivation of Hearing
C17-1	**ARC RESOURCES LTD., ENCANA CORPORATION AND MURPHY OIL COMPANY LIMITED (AEM)** Letter Dated March 14, 2012 - Request for Late Intervener Status by D. G. Davies, David J. Kehrig, Nadia Monaghan, Heather Tanaka and Garland Auvigne
C17-2	Letter dated April 3, 2012 – AEM Submitting Comments Regarding the Proposed Reactivation of Hearing
C18-1	**CITY OF DAWSON CREEK (DC)** – Letter Dated April 24, 2012 – Request for Late Intervener Status by Paul Hildebrand, Lidstone & Company on behalf of the City of Dawson Creek
C18-2	Submitted at Procedural Conference May 2, 2012 - WRITTEN REMARKS BY MR. HILDEBRAND ON BEHALF OF THE CITY OF DAWSON CREEK

INTERESTED PARTY DOCUMENTS

Exhibit No.	Description
D-1	**MURPHY OIL COMPANY ONLINE REGISTRATION** Dated July 21, 2011 – Request for Interested Party Status by Garland Auvigne
D-2	**SHELL CANADA ONLINE REGISTRATION** Dated July 29, 2011 – Request for Interested Party Status by Saif Imran
D-3	**ARC RESOURCES LTD. (ARC)** Online Registration dated August 9, 2011 – Request for Interested Party Status by David Kehrig

Exhibit No.	Description
D-4	Online Registration dated December 13, 2011 – Request for Interested Party Status by Jason Beck

LETTERS OF COMMENT

E-1	**MULVAHILL, LANCE** - Letter of Comment Dated March 22, 2012